STRATEGY

ELECTRICITY DISTRIBUTION ASSET CLASS

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PUBLIC

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DOCUMENT HISTORY

Revision	Date	Description of Changes
1.01.0		First review incorporating new template. First review incorporating new template.
2.0	30/10/2018	Review asset failure modes, asset information and expenditure.
3.0	21/08/2019	General review, asset data, performance statistics and forecast expenditure update.
4.0	20/12/2019	Updated Executive Summary
5.0	04/10/2021	Updated template – previous document number JEM AM PL 0060
5.1	18/05/2022	Updated Section
6.0	22/02/2024	General review, asset data, performance statistics and forecast expenditure update.
7.0	19/12/2024	Overall EDPR review and update

OWNING FUNCTIONAL GROUP & DEPARTMENT / TEAM

Electricity Distribution: Asset & Operations Electricity: Network Assets

REVIEW DETAILS

Review Period:	Review Date + 3 years
Next Review Due:	December 2027

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EXECUTIVE SUMMARY

Jemena Electricity Networks (Vic) (JEN), operating under a Victorian electricity distribution license, has an Asset Management System (AMS) that contains four Asset Class Strategy (ACS) documents. This ACS document pertains to Electricity Distribution Assets, a term that is used to describe assets downstream of zone substations (ie current carrying components and their associated supporting structures).

The first three sections of this ACS are common to all the ACS documents. The fourth section is where Electricity Distribution is unpacked and divided into sub-asset classes, these include:

- Poles
- Pole top structures (crossarms)
- Conductors and connectors
- Underground distribution systems
- Pole type transformers
- Non-pole type distribution substations
- Overhead line switchgear
- Low voltage (LV) overhead services
- Public lighting
- Earthing systems
- High voltage (HV) outdoor overhead fuses
- Distribution surge arrestors
- Automatic circuit reclosers

Each sub-asset class is described and discussed in terms of its associated risk, performance, life cycle management and budgetary forecasts.

All of the documented asset management strategies outlined in this document focus on keeping the probability of asset failure at a low level. This means using Condition Based Risk Management (CBRM) to forecast end-of-life asset replacement scenarios before serious failures occur. In line with standard risk assessment methodologies, asset functional failure is assessed based on a combination of probability and consequence. Should an asset failure occur, the consequence is dependent on where the asset is positioned schematically and physically in the network and the number of customers it supplies. In the case of electricity distribution assets, failures will usually result in customer interruption. In addition to customer interruption, asset failures can have safety and compliance consequences.

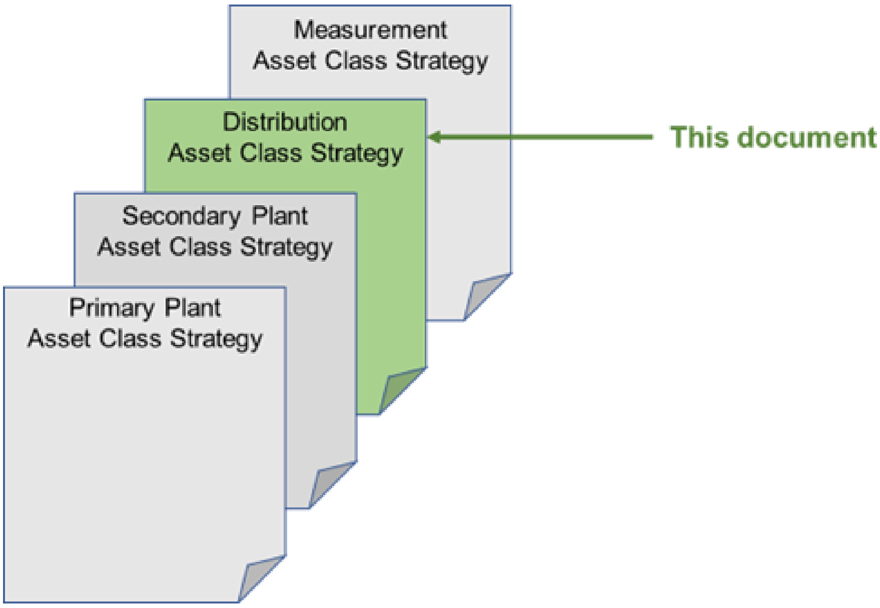
1. INTRODUCTION

This ACS covers the JEN's primary plant asset class and outlines the methods employed, analysis undertaken and actions to be taken to optimally manage the assets. The document prescribes the management of the primary plant asset class.

Asset life cycles are considered in three stages: creation (acquisition), maintenance or replacement (as applicable), and disposal. Investment recommendations across each of these three stages are made by analysing the in-situ asset condition and age profile.

There are four ACS documents. Each ACS outlines performance measures and objectives which are used to attain key performance targets. This gives visibility to the performance of the asset and, in turn, informs investment decision making.

Figure 1-1 - There are four ACS documents incorporated into JEN's Asset Management System



The distribution assets in this ACS are categorised into the following sub-asset classes located in the following sections of this document:

- 4.1 Poles
- 4.2 Pole top structures (crossarms)
- 4.3 Conductors and connectors
- 4.4 Underground distribution systems
- 4.5 Pole-type transformers
- 4.6 Non-pole type distribution substations
- 4.7 Overhead line switchgear
- 4.8 LV overhead services
- 4.9 Public lighting
- 4.10 Earthing systems
- 4.11 HV outdoor overhead fuses

4.12 Distribution surge arrestors

4.13 Automatic circuit reclosers

1.1 PURPOSE

The purpose of the Electricity Distribution ACS is to document the practical approach that supports the delivery of our asset management objectives.

This ACS is based on key information about each sub-asset (including risk, performance, life cycle management, capital expenditure and operational expenditure). Based on this information, this ACS contributes to short, medium and long-term planning.

This primary plant ACS addresses:

- Distribution plant asset management practices alignment with the ABS;
- Sub-asset class risk causes and consequences;
- Sub-asset class performance against objectives, drivers, and service levels;
- Sub-asset class specifications and life cycle management of electricity primary plant assets in-service. Asset condition, along with relative cost considerations are the primary drivers in making asset maintenance versus asset replacement decisions; and
- Risk weighted decision-making and financial estimates used to inform operating expenditure and capital expenditure planning.

1.2 ASSET MANAGEMENT SYSTEM

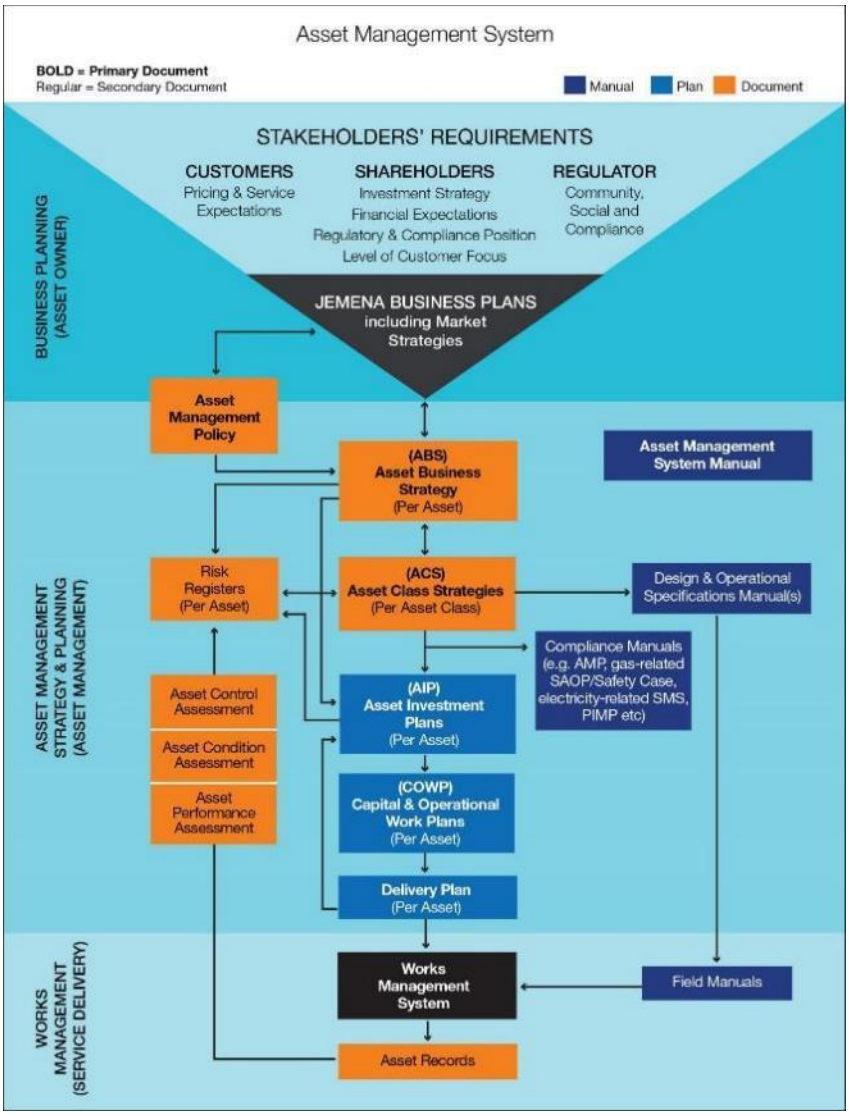
Asset management is the coordinated activity that we undertake to optimise the value of our electricity network when providing electricity distribution services to our customers. It involves balancing efficient costs, opportunities and risks against performance. An AMS enables a systematic approach to the combination of management, economic, engineering, and other practices applied to physical assets to provide the required level of service in the most cost-effective manner, whilst managing future risks.

Our AMS enables us to effectively direct, coordinate and control asset management activities throughout an asset's whole life. It facilitates an optimal mixture of efficient and prudent capital investments, operations, maintenance, resourcing, risks, performance, sustainability and good governance.

Our AMS is accredited under the ISO55001 standard. Figure 1-2 shows the inputs and outputs of the AMS, which aims to fulfil JEN's corporate strategy and objectives.

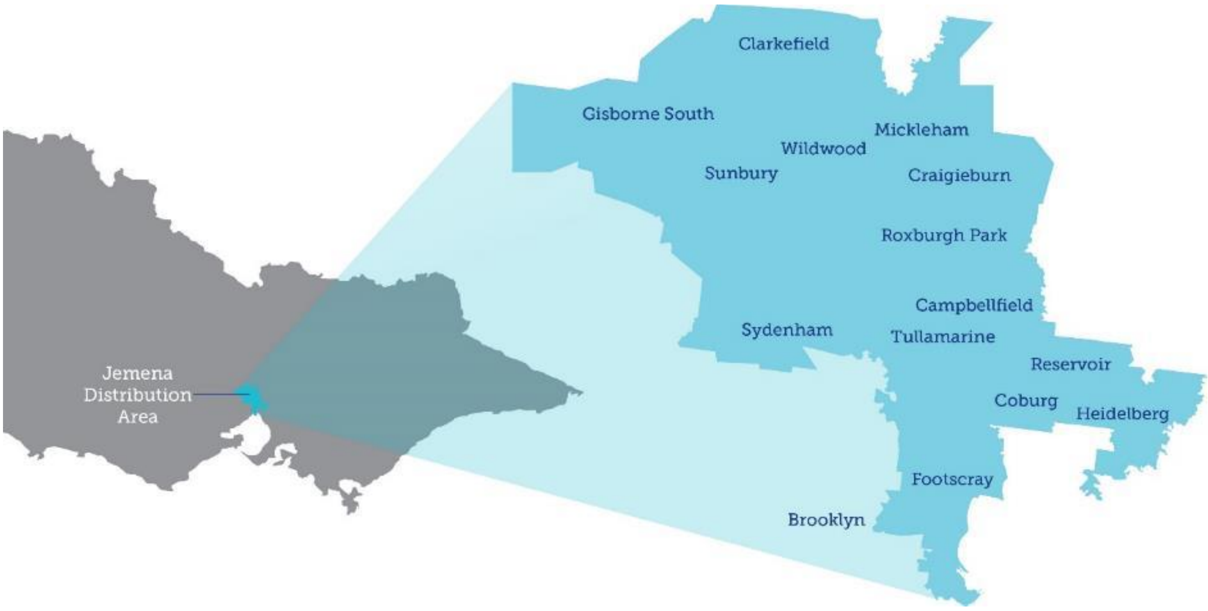
This ACS resides in JEN's AMS. The ACS ensures that the performance, risks and cost of each asset class are analysed, and optimum plans developed to align with the Business Plan.

Figure 1-2 – JEN's Asset Management System



1.3 DESCRIPTION OF ASSETS COVERED

Figure 1-3 – JEN's geographical footprint



As of 2024, our distribution assets are comprised of:

- Approximately 114,000 poles which are classified into four main groups (categories) based on the voltage of the lines being supported, they are: sub-transmission poles (ST) operating at 66kV and some 22kV, high voltage poles (HV) operating at 22kV, 11kV and 6.6kV, low voltage poles (LV) operating at 230/400V and public lighting only poles (overhead or underground supplied);
- Approximately 59,000 LV wood crossarms, 8,900 ST steel crossarms, 365 ST wood crossarms, 39,000 HV steel crossarms and 7,300 HV wood crossarms;
- Overhead conductor including: All Aluminium Conductor (AAC); Aluminium Conductor Galvanised Steel Reinforced (ACSR); Copper Conductors; Cadmium Copper Conductors; Galvanised Steel Conductors; Low Voltage Aerial Bundled Conductor (LV ABC); and a small amount of High Voltage Aerial Bundled Conductor (HV ABC);
- Air break and gas insulated load break switches, special purpose limited current breaking switches, remote controlled gas switches, disconnectors (isolators) and LV outdoor switches including switch disconnectors;
- 141 three phase 22kV and 11kV Automatic Circuit Reclosers;
- Over 77,000 public lighting lanterns;
- A total of 4,736 sets of HV outdoor overhead fuses, which consists of 3,567 Boric Acid (BA), 248 Expulsion Drop Out (EDO) and 921 Powder Filled (PF) fuse sets;
- Approximately 7,300 surge arrester sets (1 set equals 3 surge arresters generally with the exception of the single-phase parts of the HV network) at voltage levels of 22kV, 11kV and 6.6kV. Of these, over 90% are of the polymeric insulator housed type, the remainder are porcelain housed types;
- Approximately 2,680 non pole type distribution substations, consisting of five distinct subgroups by design, namely ground, indoor, underground, cubicle and kiosk type substations;
- In excess of 2,400km of high voltage and low voltage underground mains cable including oil filled cable, paper insulated cable and crossed linked polyethylene (XLPE) insulated cable;

- Approximately 158,000 LV overhead services; and
- In excess of 87,000 underground service pits.

1.4 GOVERNANCE

1.4.1 APPROVAL AND COMMUNICATIONS

The asset engineering manager updates ACS documentation every three years, which is then approved by the General Manager of Asset Management Electricity Distribution.

The ACS is reviewed every three years to ensure alignment with the Asset Management objectives and to account for any additional asset performance and risk information.

1.4.2 RESPONSIBILITIES

Key stakeholder personnel are shown below in Table 1-1.

Table 1-1: Asset Class Strategy Responsibilities

Job Title	Responsibility
Network Assets Manager	Document Owner and Approver
Distribution Team Leader	Review and draft the ACS
Asset Performance Engineers	Prepare and draft the ACS

2 STRATEGIC DRIVERS

2.1 JEN NETWORKS MARKET STRATEGY

The Electricity Distribution services that JEN provides undergoes continuous change and plays a part in shaping the future state of the energy industry.

2.2 REGULATORY AND LEGISLATIVE

JEN meets legal, licence and regulatory obligations in order to comply with the National Electricity Law (NEL) and National Electricity Rules (NER) together with other rules, codes and guidelines set out by the:

- Australian Energy Regulator (AER),
- Energy Safe Victoria (ESV), and
- Essential Services Commission (ESC)

JEN complies with the requirements of each of these stakeholders in order to adhere to its distribution licence requirements, adhere to the NER and meet safety obligations. There are ongoing compliance, analysis and reporting requirements that JEN is required to perform with regard to asset management. For example, JEN provides an annual RIN to the AER for all zone substation and distribution assets so as to account for the state of the network in terms of asset cost, age, reliability and cost of operating the network.

3 ASSET CLASS STRATEGY OBJECTIVES

ACS objectives cover:

- Promoting the Health, Safety and Environmental (HSE) culture that proactively seeks to control HSE risks;
- Optimise asset availability. Each asset failure is recorded and evaluated. Using standard risk assessment guidelines, an estimate of equipment failure rates are made. Annual probabilistic failure rates can be derived. A documented inspection, condition monitoring, maintenance and replacement strategy is included in this document for all assets to minimise the probability of failure and contain deterioration in service levels;
- Optimise asset life cycle. Defer asset replacement expenditure by assessing an asset for failure using condition monitoring. Where practical, conduct routine inspections—that can increase in frequency—as the asset approaches its statistical end of life. The aim is to defer capital expenditure whilst controlling the risk of failure and, thus, to contain deterioration in service levels; and
- Standardisation and application of established design principles minimise the design and life cycle costs of assets installed. For instance, the standardisation of specifications for purchasing primary plant assets, together with the construction of zone substation physical assets and facilities, achieves efficiencies. These coordinated and integrated designs are particularly focused on attributes of robust long life, security, reliability and cost-effectiveness and efficiency. Furthermore, we do not wait to consider disposal at end of life. Disposal of assets and associated components is accounted for within primary plant specifications and new asset evaluations prior to purchasing.

4 SUB-ASSET CLASS STRATEGIES

The Sub Asset Class Strategies provide an asset overview and identify the most appropriate strategies and plans for managing the assets over their lifecycles. Each sub-asset class strategy includes information on the asset management practices, including key strategies, options considered (that inform our expenditure plans) and work programs.

Specifically, the Sub Asset Class Strategies address the following:

- Introduction - Function and Asset Description;
- Asset Profile – Life Expectancy, Age Profile, and Utilisation;
- Performance – Requirements and Assessment;
- Risk – Criticality, Failure Modes, Current Risks, Existing Controls and Future Risks;
- Life Cycle Management – Asset Creation, Asset Operation and Maintenance, Asset Replacement, Disposal and Spares; and
- Asset Information.

4.1 POLES SUB-ASSET CLASS

4.1.1 INTRODUCTION

The pole sub-asset class covers all in-service pole types and the associated ancillary equipment (which is limited to stakes, bed-logs and stays) within JEN. Steel Public Lighting (P/L) poles will be considered in this section. P/L apparatus, such as brackets, lanterns and lamps, are covered in the Public Lighting sub-asset class strategy.

JEN manages approximately 114,000 poles, grouped as follows:

- Over 106,000 owned by JEN, including over 25,000 steel public lighting poles;
- Over 1,300 Private Overhead Electric Line (POEL) poles; and
- Over 6,300 are owned by other authorities (e.g., Telstra, Tramways, Powercor) but are supporting JEN assets.

Table 4-1 details the grouping of poles by material type and ownership. JEN is responsible (regulatory requirement) for the inspection of POEL poles and is responsible for the inspection and maintenance of JEN assets supported on other authorities' poles.

Table 4-1: Number of poles owned/managed by JEN, 2024

Ownership	Pole Material			
	Wood	Concrete	Steel	Total
JEN	60,559	19,933	25,825	106,317
Other authority	1,622	665	4,052	6,339
Private Overhead Electric Line (POEL)	693	109	590	1,392
Total	**62,874**	**20,707**	**30,467**	**114,048**

All poles are classified into four main categories based on the voltage of the lines being supported, they are: sub-transmission poles (ST, largely 66kV and some 22kV), high voltage poles (HV, largely 22kV with some 11kV and 6.6kV), low voltage poles (LV, mostly 400V with some rural supplies at

500V) and public lighting only poles (P/L, always supplied by single phase LV either overhead or underground).

If a pole supports more than one voltage, then it is referred to by the highest voltage being supported. Steel P/L only poles will be considered in this Poles section. This section will address areas of the steel P/L only poles category which are not covered in the Public Lighting sub-asset class – Section 4.9, including budget evaluations.

There are some ST poles in the JEN area that are not owned by JEN, but which support JEN lines e.g., HV, LV or P/L. The operational expenditure (e.g., asset inspection) of JEN assets on these poles is considered in this Strategy. The capital expenditure (e.g., asset replacement) of JEN assets on these poles is considered in the respective sub-asset class sections, e.g., Pole Top Structures or Conductors and Connectors.

There are some ST poles outside the JEN area owned by JEN which may support the other Distribution Businesses (DB's) lines e.g., HV, LV or P/L. The operating and capital expenditures of these poles is considered in this ACS (excluding supported assets owned by the neighbouring DB).

This chapter includes information on the asset management practices applied to poles and the associated ancillary equipment. The following sections detail the sub-asset classes asset profile, performance, sub-asset class risks, life cycle management and information/data.

4.1.2 ASSET PROFILE

4.1.2.1 *Life Expectancy*

This section details the life expectancy of the pole population for all pole types considered in the ACS. A general overview of the pole characteristics in JEN is covered, followed by details of the factors that affect the life expectancy of poles.

4.1.2.1.1 Pole Characteristics Information

The following tables in this section are provided to illustrate the characteristics of the types of poles subject to this ACS and under JEN management.

Table 4-2 shows the proportion of poles by material type as a % of the total JEN pole population.

Table 4-2: Population of poles by Material

Material	Poles	% of population of poles
Concrete	20,707	18.16%
Steel	30,467	26.71%
Wood	62,874	55.13%
Total	**114,048**	**100.00%**

Table 4-3 provides details the population of concrete poles by type. Most concrete poles are hollow core type manufactured by spinning a mould containing concrete and a welded steel mesh of reinforcement bar. A small number are solid cast (not spun) tapered I-beams, also known as coffin or Stobie poles (not to be confused with the South Australian Stobie pole, which has the structural steel on the outside of the pole).

Table 4-3: Concrete pole types

Type	No. of poles	% of concrete pole population
Cast	475	2.29%
Spun	20,232	97.71%
Total	**20,707**	**100.00%**

Steel poles require corrosion protection, which is provided by either painting or galvanising surface treatments. Steel poles are exclusively used for public lighting in underground residential settings. The steel public lighting poles used on main roads are of the impact absorbent or frangible type, which means they crumple or dislodge on vehicle impact. This protects vehicle occupants in the event of a pole impact at the expense of the pole. The cabling of these poles must be via underground connections to maintain the frangible performance of the pole. There is a small population of steel poles that are not of a frangible design, and these are sometimes supplied via overhead connections. These are relatively common in older urban areas.

There are a small number of locations on the sub-transmission network where steel poles are used to support sub-transmission assets, primarily cable termination poles at zone substation exits.

Table 4-4 indicates the treatment type applied to the steel pole population as a percentage of the entire population of steel poles.

Table 4-4: Steel pole types

Type	No. of poles	% of steel pole population
Cast	15	0.05%
Galvanised	13,073	42.91%
Painted	17,309	56.81%
Unknown	70	0.23%
Total	**30,467**	**100.00%**

JEN's population of timber poles fall into the four (4) main timber durability classes (i.e., Class 1 to Class 4). Class 1 timbers are the most durable and by definition can withstand direct contact with the ground over long periods without preservative treatment. Radiata Pine is classified as a Class 4 timber of which only a few poles exist in JEN.

When a timber pole is manufactured it is fitted with an embossed disc that carries information that includes the timber species, the length and strength of the pole and the year of manufacture. Where the pole disc is obscured or inaccessible (e.g., removed by vandals, hidden by cable guards, covered by council or Vic Roads signs or simply not installed during manufacture) the asset inspectors are asked to estimate the durability class of the wood. Where the pole disc is available the information is recorded for analysis and asset class management purposes. This facilitates the targeting of maintenance and replacement resources, and the review of assessment criteria.

Of the wood poles included in Table 4-5 below there are over 15,000 poles which have been reinstated to serviceable condition by Pole Reinforcement. This is a process where a large "nail" or pressed metal stake is driven into the ground beside an Unserviceable or Limited Life pole and the above ground portion is securely attached (bolted) to the pole. The stake is manufactured in various sizes and strengths and usually extends 1.5m below the ground and 1m above.

Table 4-5: Wood pole types

Wood Species	Durability Class* (D_{ig})	CCA	Creosote impregnated	Creosote pressure treated	Not treated	Count	% of Wood poles
Blackbutt	2	2,569	43	75	256	**2,943**	4.68%
Bloodwood	1	361	22	73	1,365	**1,821**	2.90%
Brown Stringybark	3	5	242	15	15	**277**	0.44%
Class 1	-	28	16	22	1,027	**1,093**	1.74%
Class 2	-	28	14	6	175	**223**	0.35%
Class 3	-	1	108	13	15	**137**	0.22%
Forest Red Gum	1	1	0	0	0	**1**	0.00%
Grey Box	1	128	32	175	1,183	**1,518**	2.41%
Grey Coast Box	1	8	0	0	0	**8**	0.01%
Grey Gum	1	262	341	377	2,584	**3,564**	5.67%
Grey Ironbark	1	2,505	159	1,049	9,111	**12,824**	20.40%
Ironbark	1	285	38	100	857	**1,280**	2.04%
Messmate	3	36	16,148	4,307	564	**21,055**	33.49%
Mountain Ash	4	1	41	26	5	**73**	0.12%
Mountain Grey Gum	3	0	875	252	133	**1,260**	2.00%
Other	-	51	2	3	19	**75**	0.12%
Radiata Pine	4	226	4	84	14	**328**	0.52%
Red Bloodwood	1	207	4	1	39	**251**	0.40%
Red Broad Leaved Ironbark	1	21	0	1	8	**30**	0.05%
Red Gum	2	6	0	0	8	**14**	0.02%
Red Ironbark	1	44	23	257	1,005	**1,329**	2.11%
Red Mahogany	2	109	7	5	58	**179**	0.28%
Silvertop Ash	3	2	62	60	3	**127**	0.20%
Spotted Gum	2	2,234	36	146	146	**2,562**	4.07%
Sydney Blue Gum	3	6	2	2	76	**86**	0.14%
Tallowwood	1	395	39	364	3,979	**4,777**	7.60%
Unknown	-	823	14	18	381	**1,236**	1.97%
White Mahogany	1	126	38	213	2,073	**2,450**	3.90%
White Stringybark	3	4	534	324	406	**1,268**	2.02%
White Topped Box	2	0	0	0	7	**7**	0.01%
Yellow Stringybark	3	1	24	5	48	**78**	0.12%
Total		**10,473**	**18,868**	**7,973**	**25,560**	**62,874**	100.00%
% of timber treatment type relative to wood pole population		**16.66%**	**30.01%**	**12.68%**	**40.65%**	**100.00%**	

*Durability Class as per AS 5604

Table 4-6 lists all the currently reinforced poles by species and stake type. The two (2) most used stakes are the two smallest stakes available. Messmate wood poles (Class 3 timber) are the most commonly reinforced species, but all Classes are represented.

Table 4-6: Reinforced poles by wood species

Wood Species	Dig	Stake Type									
		HS2	PB21	PB23	RFD600	RFD680	RFD880	RFD881	RFD891	RFD892	Other
Blackbutt	2	0	0	0	52	54	16	4	0	1	6
Bloodwood	1	0	0	0	74	101	62	9	11	10	13
Brown Stringybark	3	0	0	0	49	45	40	3	2	0	8
Class 1		0	1	0	145	142	59	9	8	8	11
Class 2		0	0	0	40	48	14	4	1	1	1
Class 3		2	0	0	8	20	29	3	4	0	4
Grey Box	1	3	0	1	135	154	69	9	6	9	21
Grey Gum	1	14	1	2	332	464	208	31	30	16	58
Grey Ironbark	1	9	1	0	504	697	321	81	33	30	87
Iron Bark	1	1	0	0	78	102	33	5	12	8	6
Messmate	3	81	5	6	1,317	2,676	2,548	382	312	149	612
Mountain Ash	4	0	0	0	5	14	9	0	1	2	0
Mountain Greygum	3	6	0	1	84	197	186	46	37	13	32
Other		0	0	0	2	9	0	0	0	0	0
Radiata Pine	4	0	0	0	4	5	5	0	0	0	3
Red Gum	2	0	0	0	2	0	2	0	0	1	1
Red Ironbark	1	1	0	2	81	87	25	2	3	1	9
Red Mahogany	2	0	0	0	3	3	4	1	0	0	0
Silvertop Ash	3	0	0	0	7	16	16	1	1	0	3
Spotted Gum	2	0	0	0	13	9	2	0	0	1	4
Sydney Blue Gum	3	0	0	0	15	31	9	1	0	0	2
Tallowwood	1	4	0	0	215	219	129	26	22	22	28
Unknown		0	0	0	22	28	4	0	2	1	1
White Mahogany	1	1	0	1	142	139	80	15	8	12	18
White Stringybark	3	11	1	0	146	266	137	11	13	1	38
Yellow Stringybark	3	0	0	0	12	21	6	0	3	2	3
Total		**133**	**9**	**13**	**3,487**	**5,547**	**4,013**	**643**	**509**	**288**	**969**

After inspection and testing the condition of a pole is classified as either Serviceable, Limited Life or Unserviceable. These pole conditions are defined as follows:

- Serviceable – may remain in service until the next routine inspection;
- Limited Life – must be reinstated (by reinforcement) or reassessed within 12 months; and
- Unserviceable – must be reinstated (by reinforcement) or replaced within 12 weeks.

Refer to the Asset Inspection Manual (AIM) - JEN MA 0500 for a full explanation and specified criteria of the above conditions.

4.1.2.1.2 Factors affecting life expectancy

As per the Network Asset Useful Lives Procedure - ELE PR 0012, the life expectancy of a pole varies depending on the pole material. The expected useful life (age over which the pole is depreciated) of JEN's poles are:

- Wooden Poles – 54 years;
- Concrete Poles – 70 years; and
- Steel Poles – 35 years.

The life expectancy of a wooden pole is influenced by a number of factors that include:

- Durability class or species of the timber;
- Soil type and conditions conducive to timber decay;
- Termite areas;
- Vehicle impacts – location in relation to roads;
- Correct application of assessment criteria;
- Wood preservative treatment pre purchase and the on-going wood treatment;
- Water ingress or fungal fruit causing pole top rot; and
- Pole top fires.

The average age of the in-service wood pole population is 39 years, which means that a large proportion is entering the latter stages of their expected life span. Of the wood pole population 66% are 35 years or older with 22.4% being more than the expected useful life of 54 years.

An analysis of the age of wooden poles when they have been removed has indicated an average age of 37.26 years. JEN has recorded the details of 20,029 removed poles. This number excludes any "Null" ages and ages less than 10 years (difference between install date and remove date).

Concrete poles are far more durable than wooden poles and the factors that affect their life expectancy are limited to:

- Pole construction type, spun or cast;
- Soil type and conditions conducive to the corrosion of reinforcing bars; and
- Vehicle impacts – location in relation to roads.

The average age of the concrete pole population is 30.9 years. Unlike the wood pole population, a large proportion of concrete poles are well below the designed life span: 80.5% of the concrete pole population is under 40 years of age. The pole age profile is elaborated on in the life cycle management section.

The life expectancy of JEN's population of steel poles and towers is influenced by the following factors:

- Soil type and conditions conducive to the corrosion of metals;
- Preservative treatment of the steel, galvanising and bitumen paints; and
- Vehicle impacts – location in relation to roads.

JEN's in-service steel poles have an average age of 15.65 years. Of the steel pole population 91.6% are classified as P/L poles. Of the P/L steel pole population 2.86% are over the age of 35 years. There are 22 JEN owned sub transmission steel towers with an average age of 60 years. The life expectancy of a steel tower is 70 years. Of the steel tower population seven of the 22 ST steel towers are over 60 years of age.

The breakdown frequencies for pole structures are monitored on a monthly basis (by the Asset Performance Review Committee). The data used for the assessment of breakdown frequency is extracted from JEN corporate systems (Geographic Information System (GIS), System Applications and Products (SAP), Outage Management System (OMS). This data is monitored to identify trends, which may indicate possible strategic deficiencies. Where there are marked changes in breakdown frequency, either increasing or decreasing, then the causes are carefully investigated.

The failure categories which apply to the evaluation of this performance indicator are:

- electrical faults caused by pole failures; and
- in-service pole failures.

In-service pole failures do not include pole failures due to external causes such as vehicles impacts or trucks striking communication cables.

Pole top rot can have a significant impact on the life expectancy of wood poles if appropriate precautions are not taken. The pole top exposes the end grain of the timber and needs to be protected against the weather. The installation of a pole cap to protect the pole top from water ingress and consequential rot is an effective preventative.

Line inspectors are required to raise a maintenance notification for all missing or dislodged pole caps on timber poles. These are rectified in accordance with the assigned priority.

Rigorous maintenance of pole caps ensures the incidence of pole top rot is maintained at levels below one per annum. There are currently no poles with pole top rot on the JEN network.

4.1.2.2 *Age Profile*

This section provides a summary of the age profile of poles and reinforced poles.

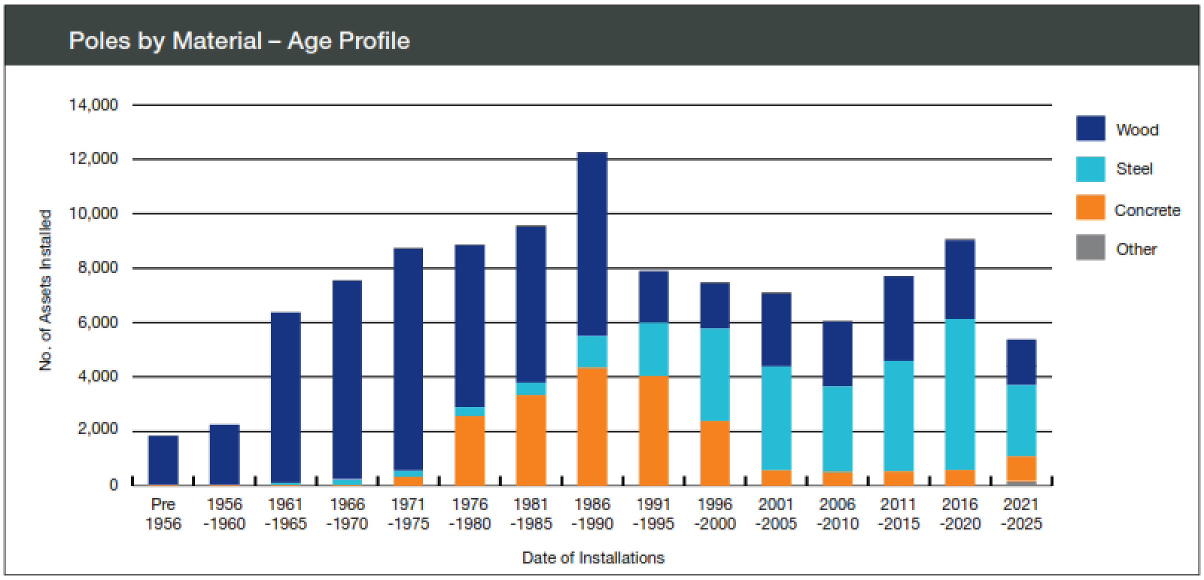
A number of features of the Pole age profile are:

- Up until 1975, the most commonly used material was wood, almost exclusively;
- The two decades of the '70's and '80's saw an increasing number of poles installed and an increasing preference for concrete and steel poles;

- The increasing use of steel poles is associated with the development of underground residential distribution (URD) technologies and the associated use of steel streetlighting poles, including decorative steel poles;
- Since the privatisation of the State Electricity Commission (SEC) and 11 Municipal Electricity Undertakings (MEU's) the volume of HV and LV distribution poles installed annually has been steadily reducing. Again, the policy of undergrounding new residential estates has been the main influence on this reduction;

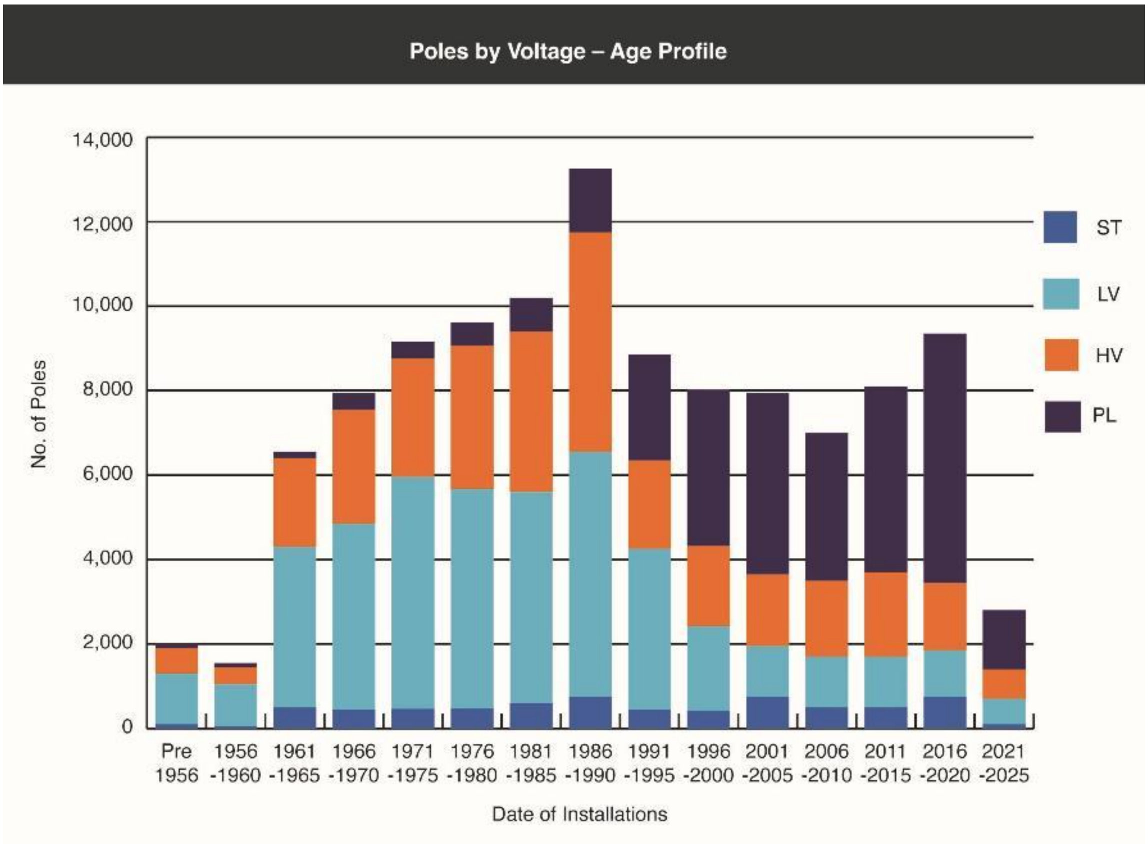
In the late '90's it was identified that the initial cost of installing concrete poles was noticeably more than for the equivalent wood pole. Consequently, CCA-treated wood poles were adopted as standard, and the use of concrete poles for replacement and construction activity was reduced significantly. Concrete poles were only used rarely and only to satisfy specific design requirements and in late 2020 JEN mandated the use of concrete poles in the Hazardous Bushfire Risk Area (HBRA) for all new construction and pole replacement work provided technical and safety criteria allow.

Figure 4-1: Pole age profile by material



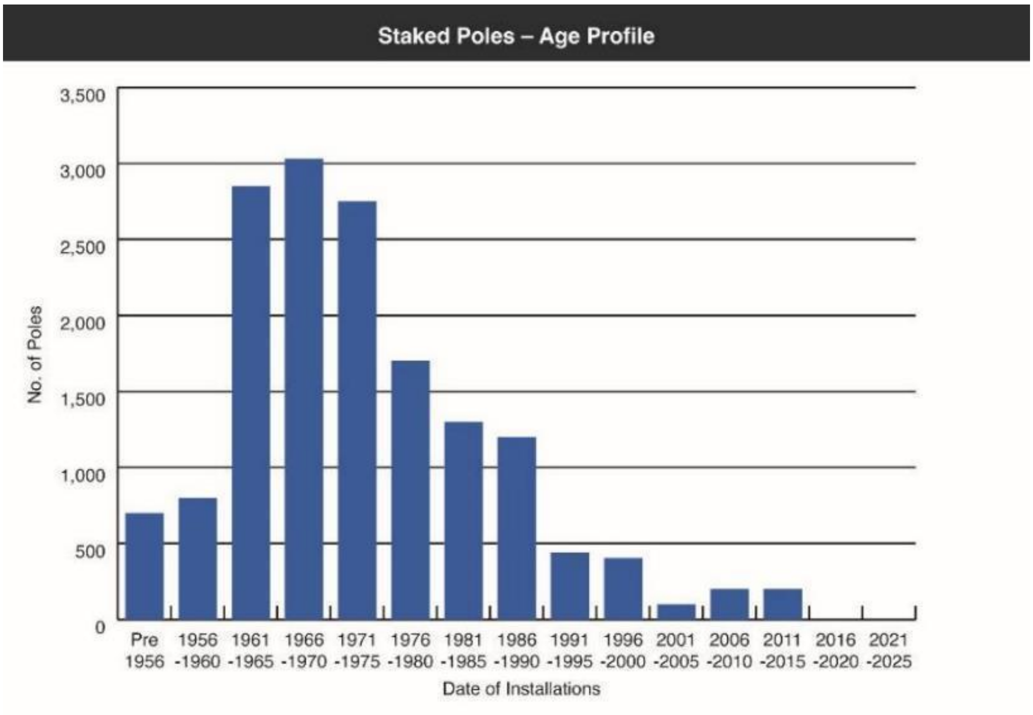
Both Figure 4-1 and Figure 4-2 indicate the increased rate at which steel public lighting poles have been installed as a result of the mandating of URD. The use of underground distribution technologies has slowed the rate at which poles are installed generally (with the exception of public lighting poles) so most new HV and LV distribution pole installations are currently associated with the maintenance and replacement of the existing overhead network.

Figure 4-2: Pole Age Profile by Voltage (Not including Reinforced Poles)



The age profile of Reinforced Poles is indicated in Figure 4-3 and the age profile of the stakes themselves is indicated in Figure 4-4.

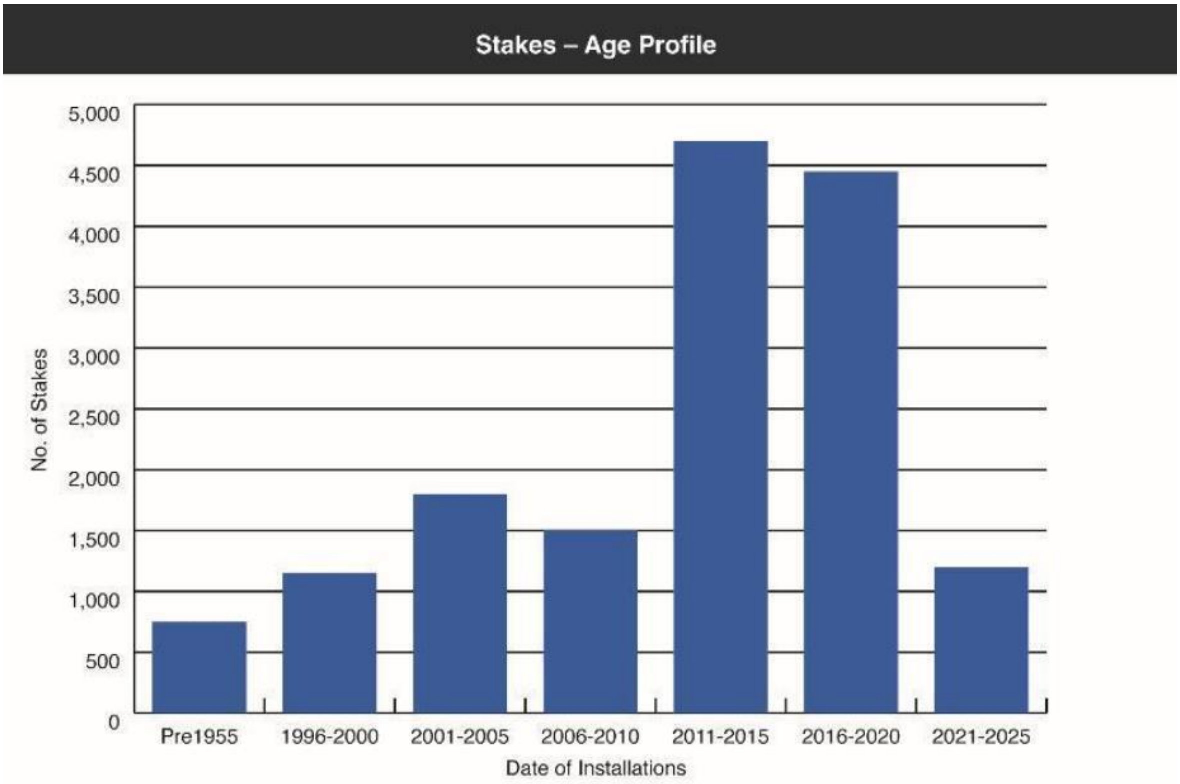
Figure 4-3 Age profile of reinforced poles



Of the 17,000 poles that have been reinforced approximately 50% are installed on poles that have exceeded the expected pole life of 54 years and 90% are installed on poles that are aged 30 years or older.

The age profile of the reinforcing stakes (the steel stakes) deployed on the JEN network is indicated in Figure 4-4 below.

Figure 4-4: Age profile of Stakes (nails)



Some features of this age profile are:

- Although some poles were reinforced before privatisation in 1994, the practice was embraced post privatisation.
- During the 2011-2015 period and the 2016-2020 period, high volumes of pole reinforcement occurred that was associated with a program of works undertaken to address performance issues with a family of poles found to be undersized based on girth measurements and a family of LV poles fitted with HV raiser brackets.
- JEN has amended its asset management strategy in the HBRA. In this area reinforcing stakes are no longer installed. Poles identified as LL or US in the HBRA are replaced using concrete poles wherever technical and safety considerations permit.

4.1.2.2.1 Volume of poles approaching the end of life

The pole testing criteria define the end of life or, alternatively, the useful life of a pole, which results in a pole being classified as unserviceable.

Analysis of the age of wooden poles at replacement indicates that the average age of a wood pole when replaced is 37.26 years. This is significantly less than the expected nominal pole life used of 54 years. JEN will continue to use an average life of 54 years in CBRM analysis (refer to ELE PR 0012 Review of Asset Lives Document for details) while the expected nominal asset life is reassessed as increased volumes of data become available.

The nominal pole ages used in the replacement model are likely to understate the volume of poles in the wear-out phase. The proportion of the JEN wood pole population that exceeds their nominal life is shown in Figure 4-5. This is based on the nominal life of a wood pole being 54 years.

If no pole replacements occur, over the next 5 years, the proportion of wooden poles older than their nominal life will increase from 27.8% of the wood pole population currently to around 38.4%. The chart indicates the effect of the historic and forecast replacement and reinforcement rates on the percentage of wood poles that exceed the nominal life. This representation takes no account of condition or asset health but does indicate that a significant percentage of the wood pole population exceeds the nominal 54-year life used for wood poles and that this percentage will continue to grow despite the current rates of pole replacement and reinforcement.

Figure 4-5: % of Wood Pole Population that Exceeds Nominal Life

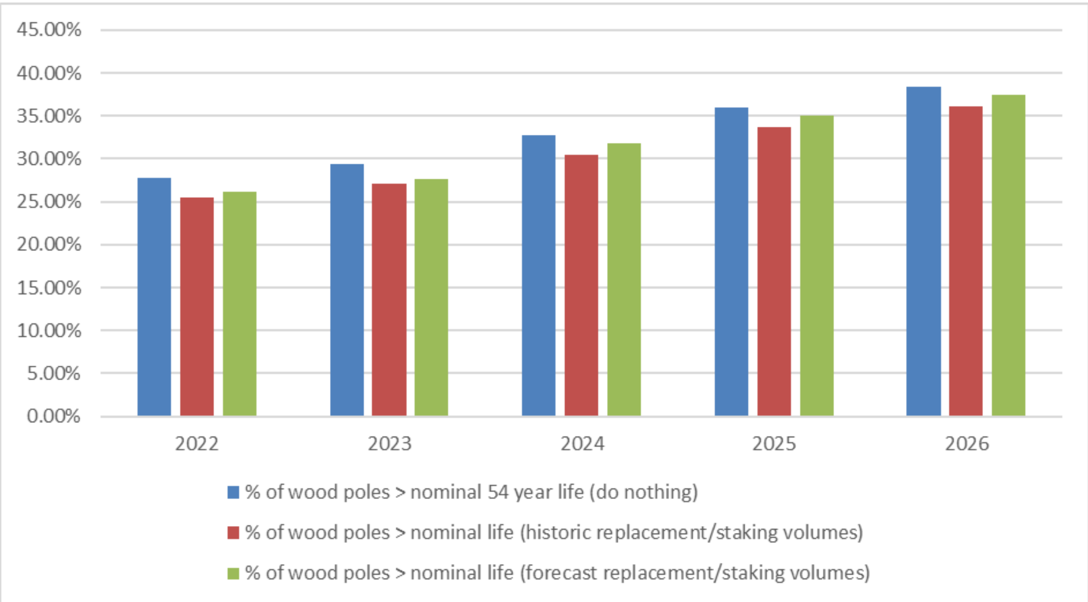


Figure 4-6 indicates the condemnation rates for poles from 2001 to 2022. This condemnation rate includes wood, steel and concrete poles of all classifications. The condemnation rate used is defined as the total number of poles classified as LL (limited life) or US (unserviceable) in any year divided by the total number of JEN-owned poles in that year (or the total pole population) expressed as a percentage.

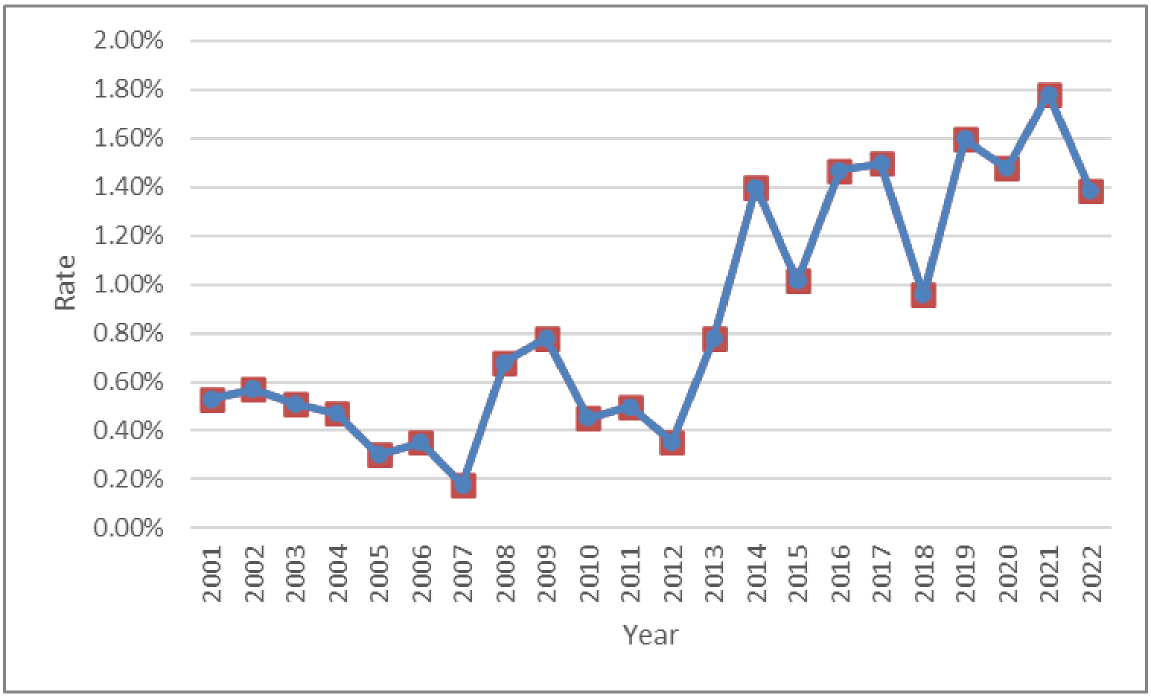
The rate at which poles are being condemned is an increasing trend and this is consistent with the increasing percentage of poles that have exceeded their expected age (Figure 4-5). The age profile of the pole population (Figure 4-1) also clearly indicates the large number of wood poles that were installed from 1960 through to 1975, a period of rapid growth. These wood poles are all now approaching or are beyond the nominated useful life of 54 years and increased condemnation rates are inevitable.

Care needs to be taken when interpreting the data on condemnation rates. Year on year rates are affected by the zones being tested and the relative proportion of Class 3 poles in these areas. In addition, the criteria for pole testing were adjusted in 2012 which resulted in elevated condemnation rates after 2012.

Allowing for the effects of the change in testing criteria and other policy changes in relation to the reinforcement of poles in the HBRA and the fact that a full testing cycle has passed since the introduction of the new criteria, condemnation rates are expected to reduce to approximately 1.0% over the next few years and further trend down over the next 5 years.

For more information on the forecast volume of poles replacements refer to Section 4.1.5.

Figure 4-6 JEN pole condemnation rate (as a % of total pole population)



4.1.2.3 *Utilisation*

The section provides high-level information on how poles are utilised (operated). This section includes details of any particular utilisation constraints that are placed on poles:

- For poles, maximum asset life equals (=) maximum utilisation. All poles remain in service until their condition is assessed as Unserviceable (US) and they cannot be reinforced (a number of reasons may exist). The routine condition assessment and treatment (wood poles only) program is designed to assist the attainment of maximum utilisation of the pole asset class.

- As from 2020 concrete poles are installed in the HBRA for all new construction and pole replacement work. This is to ensure the risk of a fire start associated with a pole failure in the HBRA is minimised. It also is designed to increase the resilience in the event of a fire in the HBRA so that the network can recover as rapidly as is possible.
- Reinforcement of Limited Life (LL) and US poles is a life extension treatment and is a cost-effective method of extending asset life and is utilised wherever the assessment criteria is met in the LBRA.
- Reinforcement of poles in the HBRA no longer occurs, once a pole is classified as LL or US in the HBRA it is now replaced with a concrete pole wherever technical and safety considerations permit.
- A program has been established to replace all existing reinforced poles in the HBRA with concrete poles.
- Augmentation or customer projects may occasionally replace poles with remaining life.
- It is JEN policy to use wood poles wherever possible on the overhead distribution network in the LBRA. Wood poles are used for all voltage classes, i.e., ST, HV, LV, and P/L. Wood poles are not normally used for P/L but may be used to replace an existing wooden P/L pole.
- Steel poles are used for P/L in accordance with JEN’s P/L Technical Standard. All steel poles used today are frangible in one of two ways:
  - Impact absorbing (crumple under vehicular impact); or
  - Slip base (the poles detach from the base at ground level).
- It is a VicRoads requirement that all new P/L poles on main roads be frangible with a preference for slip base poles.
- In the LBRA concrete poles are predominantly used for technical reasons where pole loads are such that wood pole characteristics e.g., length and/or strength, do not meet the requirements. As reinforced concrete is an engineered product it may be manufactured in lengths and strengths which are not available in wood poles, hence in some rare cases it may be used where there is insufficient space for the installation of a ground stay supported wood pole. On rare occasions concrete poles may be used for aesthetic reasons, for example where a pole replacement is required (e.g., after a vehicle impact) and all the other poles in the street are concrete.
- Concrete poles are used for all pole type substations to satisfy pole loading requirements.

Table 4-7: Population of Poles by Material and Classification” shows a breakdown of the quantity of poles per material and voltage classification. Wood continues to be the most commonly used material for JEN distribution poles.

Table 4-7: Population of Poles by Material and Classification

Category	Classification	Material			Total
		Concrete	Steel	Wood	
ST	ST	718	16	2,174	2,908
	ST/HV	247	0	862	1,109
	ST/HV/LV	103	0	1,304	1,407
	ST/LV	43	11	1,026	1,080
	ST Total	1,111	27	5,366	6,504
HV	HV	1,144	11	3,449	4,604
	HV/LV	6,122	19	22,361	28,502

	HV Total	7,266	30	25,810	33,106
LV	LV Total	11,017	2,326	29,933	43,276
P/L	PL Total	1,192	27,886	1,185	30,263
Stay	Stay Total	52	4	349	405
Other/unknown	Other	69	194	231	494
Total		**20,707**	**30,467**	**94,050**	**114,048**

Currently approximately 18% of the poles deployed on the JEN are concrete. Steel poles are exclusively used for public lighting (there are a handful of exceptions to this). Embossed nameplates (also known as belly buttons due to the attachment method) are fixed to wood poles. These carry information such as: species, date of manufacture, length, strength, treatment type and purchasing organisation (JEN in our case). Concrete poles have similar information cast into the concrete. Some approved non-standard steel poles carry a nameplate, but most steel poles do not.

A Public Lighting Technical Standard (Doc No. JEN PR 0026) is maintained which specifies steel pole dimensions, material and treatment i.e., hot dip galvanising and additional anticorrosion coating for the in-ground portion of the pole. This standard also lists a number of approved non-standard poles which public lighting customers may choose to install.

JEN owns all unmetered P/L assets (poles and wires) located in the road reserve and charges an operate, maintenance and replacement (OM&R) fee to public lighting customers for providing this service. The fee is calculated based on the use of standard equipment (as defined in the JEN P/L Standard). Customers who choose to install approved Non-Standard equipment (also defined in the JEN P/L Technical Standard) have an ongoing obligation to supply all non-standard equipment spares. JEN is responsible for the operation, maintenance and provision of labour for the replacement of approved non-standard P/L equipment.

4.1.3 PERFORMANCE

The performance of the pole sub-asset class is monitored using measures such as, in-service failure rates and pole condemnation rates. The performance requirements are defined within the JEN technical material specifications, the associated and nominated Australian Standards, the JEN Construction Standards, and the JEN Design Standards.

4.1.3.1 *Requirements*

There are three principal material specifications that define the requirements for these assets. These are the:

- wood pole specification;
- concrete pole specification; and
- steel pole specification.

Each of these specifications reference a number of Australian Standards and the principal of these are listed in Table 4-8.

Table 4-8: Poles – Relevant Australian Standards

Standard ID	Standard Title
AS/NZS 2878	Timber Classification into Strength Groups
AS 3818.1	Timber-Heavy Structural Products-Visually Graded, Part 1 General

Standard ID	Standard Title
AS 3818.11	Timber-Heavy Structural Products-Visually Graded, Part 11 Utility Poles
AS 5604	Timber – Natural Durability Ratings
AS/NZS 7000	Overhead Line Design
AS 4680	Hot Dipped Galvanized Coatings on Ferrous Articles
AS 1074	Steel Tubes and Tubulars for Ordinary Service
AS/NZ 1163	Cold-formed Structural Steel Hollow Sections

In addition to the performance requirements specified in the JEN material specifications, the in-service performance requirements of the pole sub-asset class are specified and governed by the application of the following JEN Standards:

- Overhead Line Design Manual – ELE 999 OM DN 001 (previously JEN MA 0005);
- Distribution Construction Manual - ELE 999 OM CN 001 (previously JEN MA 0006);
- Public Lighting Technical Standard – JEN PR 0026.

These standards define the installation requirements and ensure the achievement of the designed performance requirements in terms of pole loads and clearances.

At JEN safety is our number one priority. Poles are located in the public domain so consequently the in-service failure of a pole can have significant safety implications for JEN employees and the general public. The management of the performance of this group of assets is one of JEN's major network management activities and is based on a number of condition monitoring programs and targeted maintenance and replacement programs.

The maintenance of the structural and electrical integrity of JEN's pole population is fundamental to the achievement of JEN's network performance targets, supply quality targets and the safety of the network as a whole.

In the period leading up to 2017 an increase in the rate of in-service pole failures of Class 3 timber poles was detected. In order to manage this issue, the pole inspection criteria for Class 3 timber poles was modified (sound wood measurement for Class 3 poles) to ensure that the mean time to failure of this pole type exceeded the inspection period. The consequence of this change to the inspection criteria was an increase in the condemnation rate for these types of poles and this is expected to continue over one inspection cycle. The change to the inspection criteria does appear to have addressed the in-service failure rate.

In service pole failures are investigated on an individual basis with relevant actions being identified to improve performance.

4.1.3.2 *Assessment*

The assessment of the performance of the pole population is based on the rate of unassisted in-service pole failures. Table 4-9 provides the results of in-service pole failures for the period 2010-2024.

Table 4-9: In service pole failures

2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	FY 21	FY 22	FY 23	FY 24
1	0	1	3	0	2	7	3	2	4	5	1	1	0	1

This table indicates that safety performance of the pole sub-asset class has recently improved due to actions being implemented to mitigate the risk of in service pole failures through modification and tuning of the asset inspection criteria. The data above specifically portrays unassisted pole failures, and excludes vehicle impact causing pole failure.

The accurate analysis and assessment of the performance of this sub-asset class is dependent upon the following factors:

- A very high level of confidence in the accuracy and completeness of asset data (characteristic and condition);
- The correct application of the asset condition assessment criteria by asset inspectors; and
- The accurate reporting and recording in JEN's corporate systems (e.g., SAP) of pole failure data.

Throughout this strategy the poles sub-asset class has been categorised by voltage as follows; Sub transmission (ST), High Voltage (HV) and Low Voltage (LV). Each voltage category has been modelled using the CBRM methodology and the output provided in this section. At this time the P/L category is out of scope for CBRM modelling and will be considered for inclusion in subsequent revisions of this strategy or the P/L strategy.

The CBRM modelling provides an output in the form of Health Indices. These provide a visual demonstration of the condition of the various categories of poles now and a forecast of future condition.

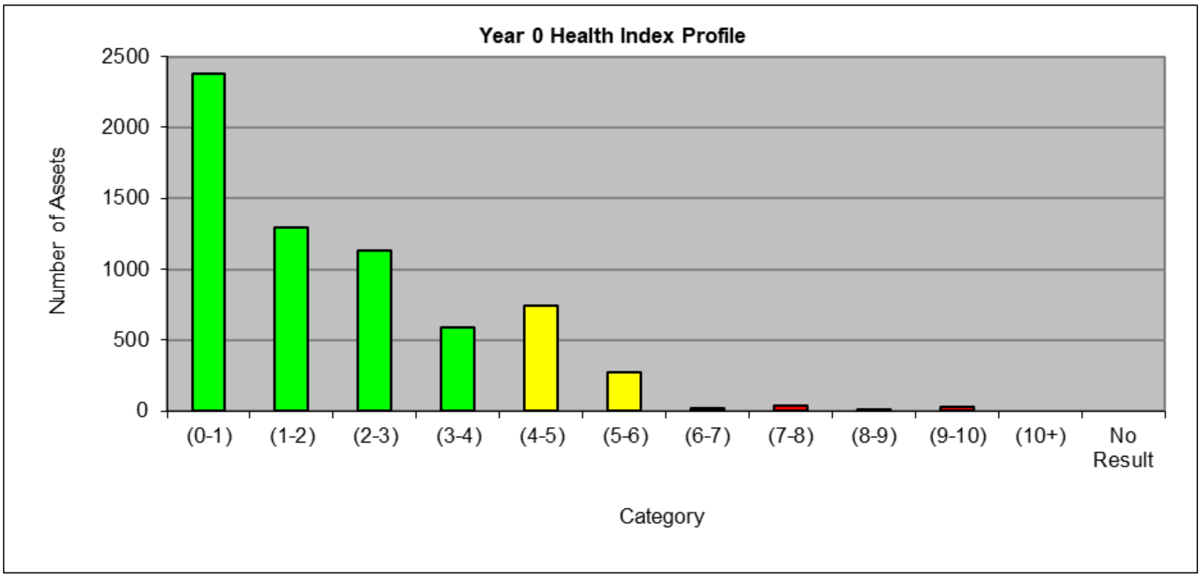
4.1.3.2.1 ST Poles Condition Assessment

The CBRM results in terms of the health index for the current year (Year 0) are shown in Figure 4-7.

This measure of asset health is based upon the current level of expenditure on programs intended to maintain and replace this asset type. These include the asset inspection program, the pole reinforcement program and the end of life pole replacement program. The CBRM model identifies 63 poles currently in poor condition, that is with a health index of 7 or greater. This is approximately 1% of the ST pole population.

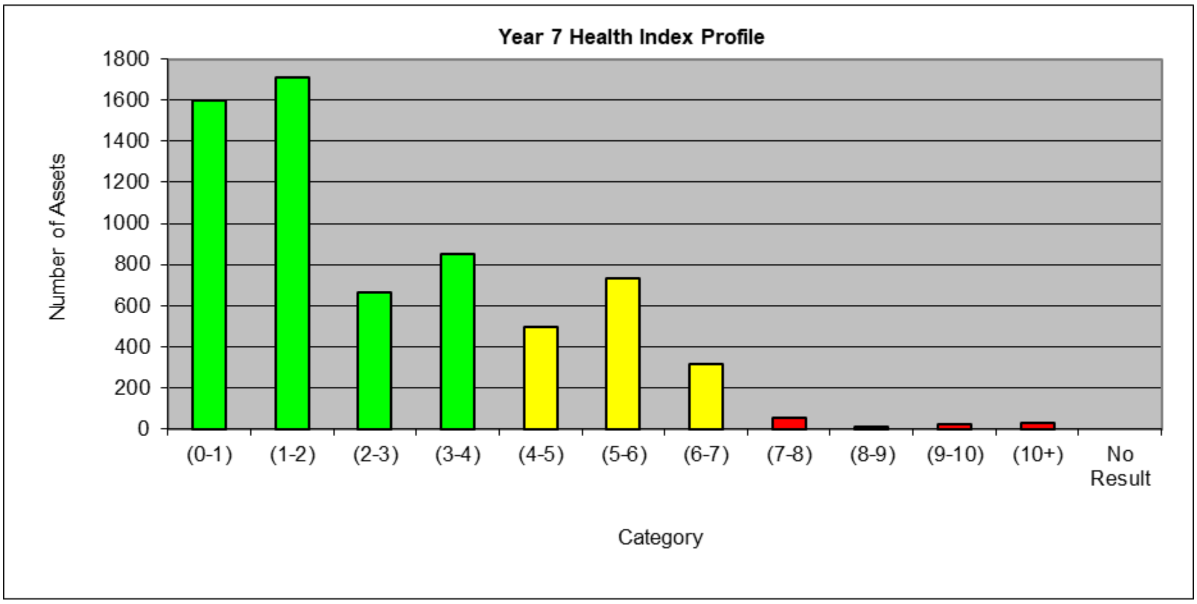
End of pole life for these purposes is when the pole is classified as unserviceable. It does not include poles that are replaced as a result of third party factors (e.g., vehicle impact).

Figure 4-7: Year 0 (2024) Health Index Profile (ST poles)



By year 7 (2031), if no ST poles are reinforced or replaced, the health index changes as shown in Figure 4-8. A total of 124 poles will be in poor condition with an associated higher probability of failure (health index of 7 or greater).

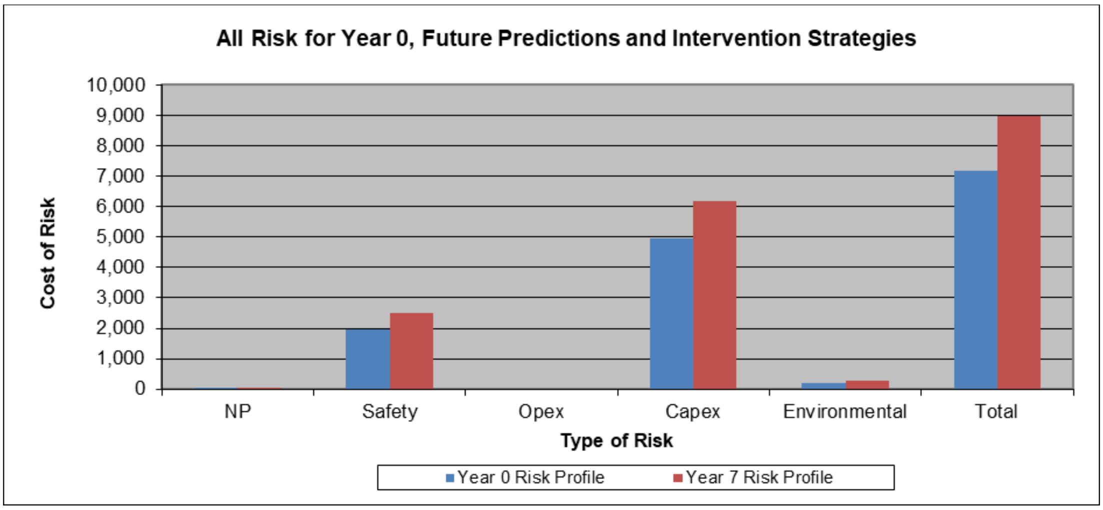
Figure 4-8: Year 7 (2031) Health Index Profile (ST poles)



This result (Figure 4-8) indicates that the majority of the population of ST poles are well below their expected life of 54 years for wood poles and 70 years for concrete poles. Contributors to the total risk cost include Network Reliability, Safety, Operating expenditure, Capital expenditure and the Environment, as indicated in Figure 4-9 below. The main factors contributing to the risk to the network should a ST pole fail are Safety and Capex as indicated in Figure 4-9. This reflects the redundancy in the design of the sub transmission network so that a ST pole failure has little direct impact on Network Performance. ST poles identified as being in poor condition at Year 0 will be monitored by the established pole inspection and testing programs. These will be replaced or reinforced in accordance with JEN's established pole management policies and practices.

In order to maintain the assessed risk associated with the operation of these assets at current (year 0) levels this strategy proposes the replacement or reinstatement of approximately 15 ST poles per annum over the next 5 year period. This is consistent with a condemnation rate of 0.3% of the ST pole population per year and significantly less than the current condemnation rate.

Figure 4-9: Risk Profile for Year 0 (2024) & Year 7 (2031), ST Poles



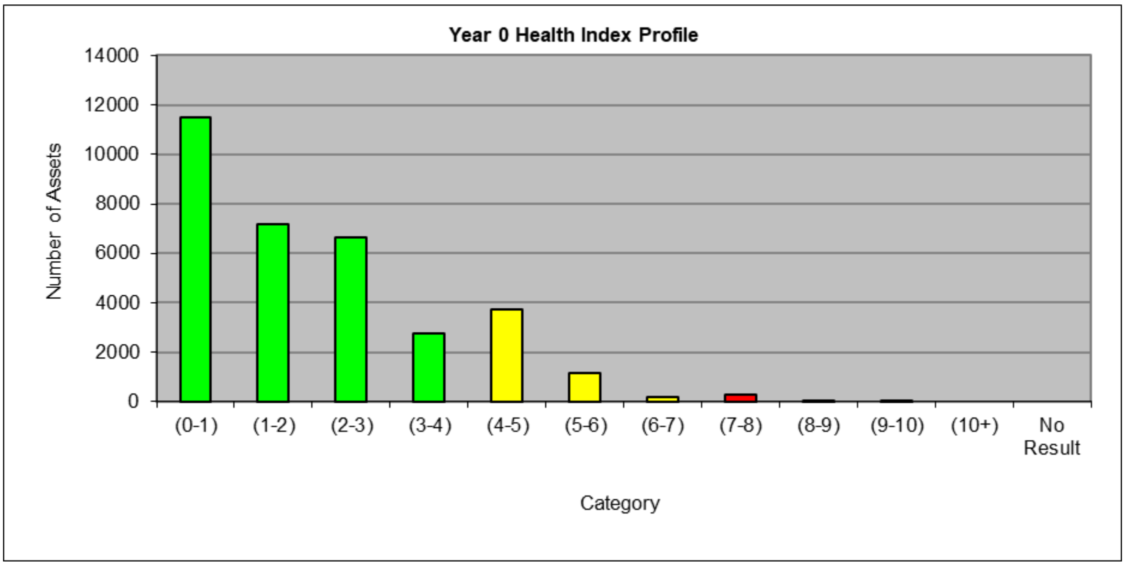
4.1.3.2.2 HV Poles Condition Assessment

The CBRM results for HV poles in terms of the health index for the current year (Year 0) are shown in Figure 4-10.

This measure of asset health is based on the current level of expenditure on programs intended to maintain and replace this asset type. These include the asset inspection program, the pole reinforcement program and the end-of-life pole replacement program. The total estimated cost of risk for all failure scenarios at Year 0 for HV poles is calculated to be $202k per annum with a current condemnation rate for all poles of 1.4% per annum. The CBRM model identifies 325 poles currently in poor condition, that is with a health index of 7 or greater. This is approximately 1% of the HV pole population.

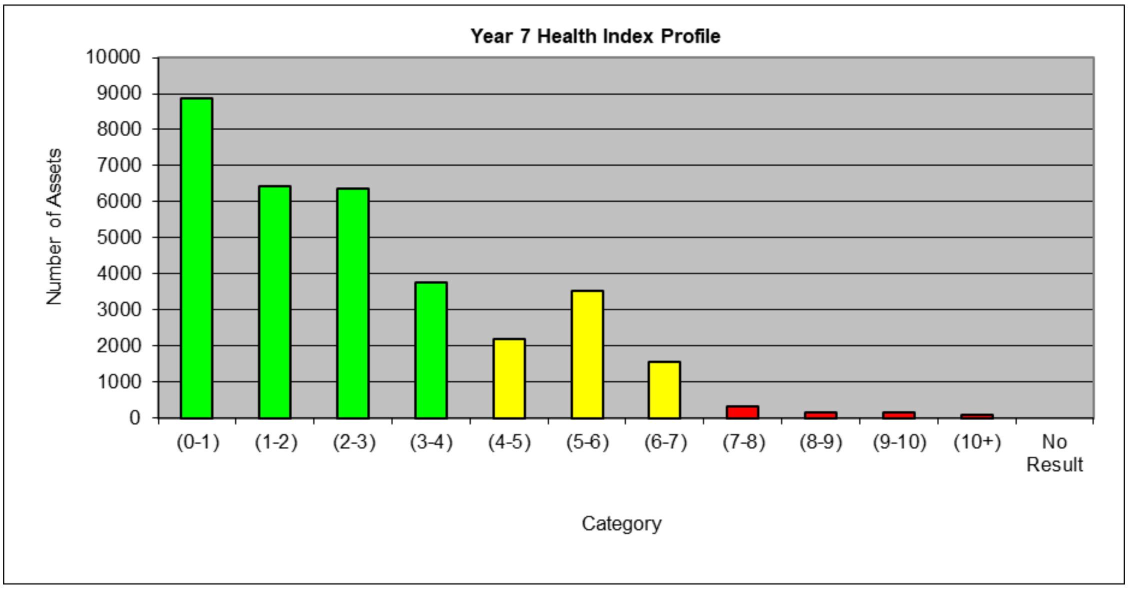
End of pole life for these purposes is when the pole is classified as unserviceable. It does not include poles that are replaced as a result of third-party factors (e.g., vehicle impact).

Figure 4-10: Year 0 (2024) Health Index Profile (HV Poles)



By year 7 (2031), if no HV poles are reinforced or replaced, the health index changes as shown in Figure 4-11. The CBRM model predicts a total of 716 poles will be in poor condition with an associated higher probability of failure (health index of 7 or greater).

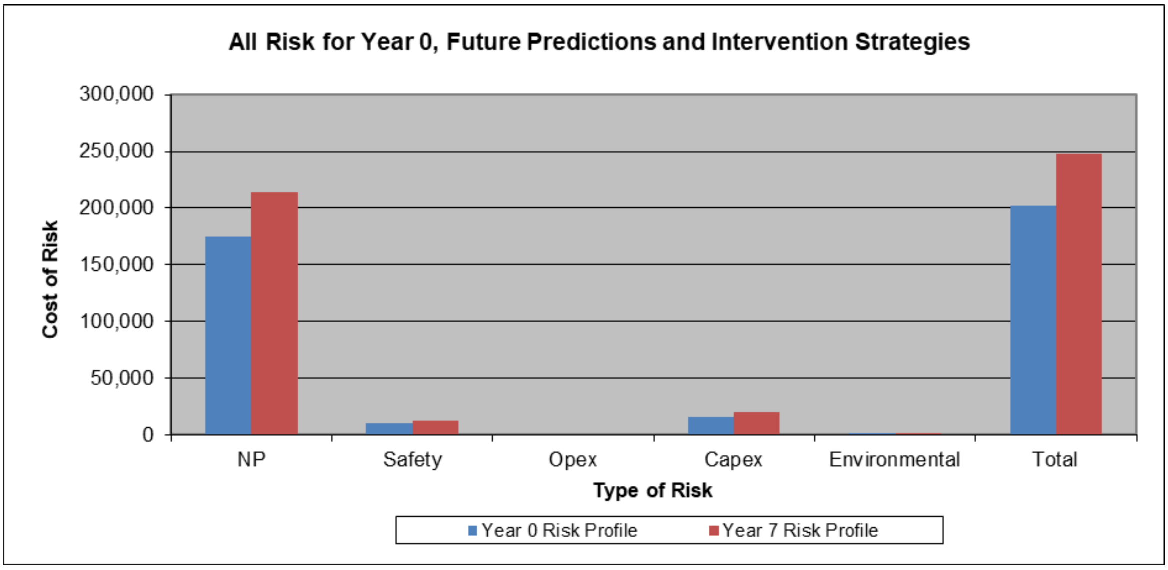
Figure 4-11: Year 7 (2031) Health Index Profile (HV Poles)



This result (Figure 4-11) indicates that the majority of the population of HV poles are well below their expected life of 54 years for wood poles and 70 years for concrete poles and that pole condemnation rates will reduce or at least remain at current levels. Contributors to the total risk cost include Network Reliability, Safety, Operating Expenditure, Capital Expenditure and the Environment. The main factor contributing to the risk to the network should a HV pole fail is Network Reliability as indicated in Figure 4-12. The HV poles identified as being in poor condition at Year 0 will be monitored by the established pole inspection and testing programs. These will be replaced or reinforced in accordance with JEN's established pole management policies and practices.

To maintain the assessed risk associated with the operation of these assets at current (year 0) levels this model proposes the replacement or reinstatement of approximately 220 HV poles per annum based on condition over the course of the next 5 year period. This is equivalent to a condemnation rate of 0.4% of the HV pole population and less than the current condemnation rate of 1.0% of the population per year and indicates a reducing trend in pole condemnation based on the health indices of the HV pole population.

Figure 4-12: Risk Profile for Year 0 (2024) & Year 7 (2031), HV poles



*NP refers to Network Performance

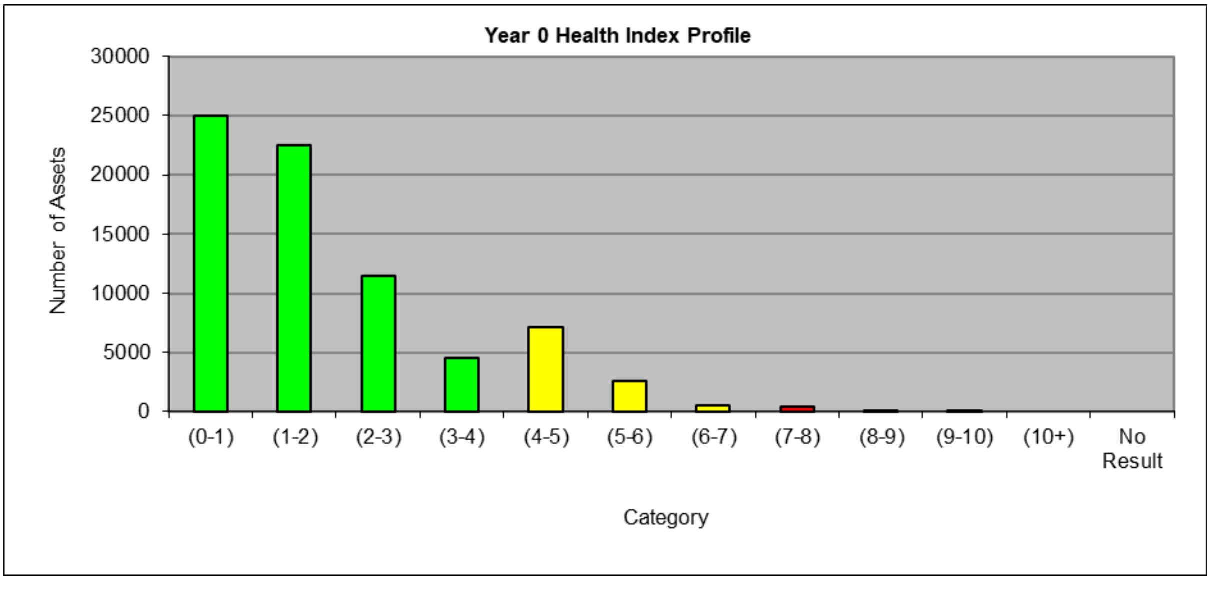
4.1.3.2.3 LV Poles Condition Assessment

The CBRM model results in terms of the health index for the current year (Year 0) are shown in Figure 4-13.

This measure of asset health is based upon the current level of expenditure on programs intended to maintain and replace this asset type. These include the asset inspection program, the pole reinforcement program and the end of life pole replacement program. The CBRM model identifies 581 poles currently in poor condition, that is with a health index of 7 or greater. This is approximately 0.8% of the LV pole population.

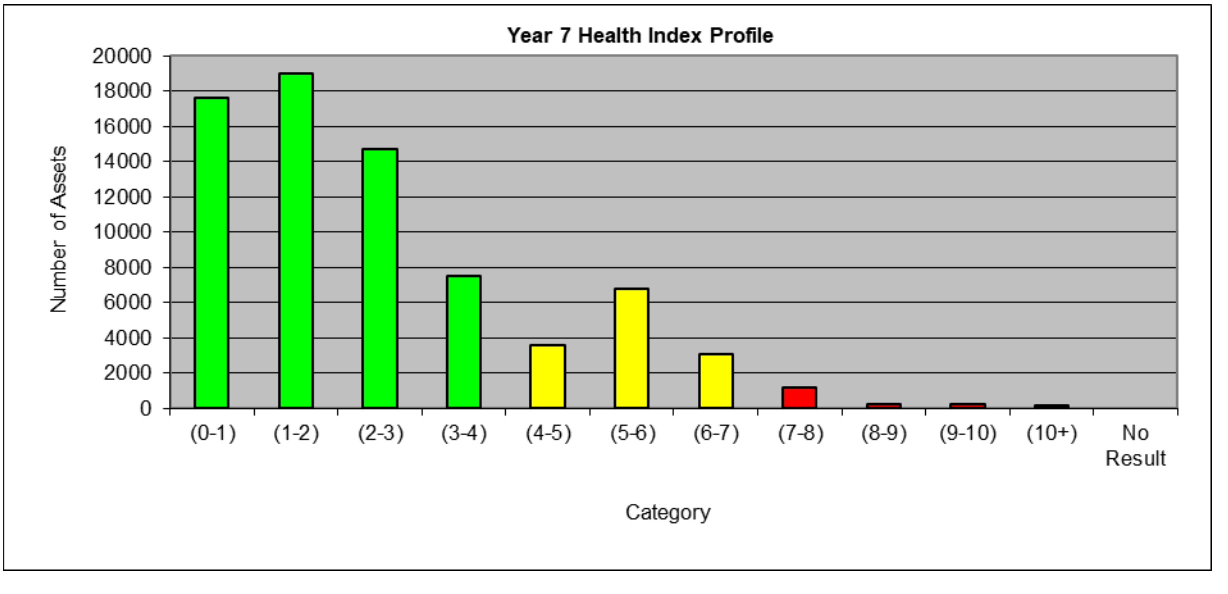
End of pole life for these purposes is when the pole is classified as unserviceable. It does not include poles that are replaced as a result of third party factors (e.g., vehicle impact).

Figure 4-13: Year 0 (2024) Health Index Profile (LV poles)



By year 7 (2031), if no LV poles are reinforced or replaced, the health index changes as shown in Figure 4-14. A total of 1948 poles will be in poor condition with an associated higher probability of failure (health index of 7 or greater).

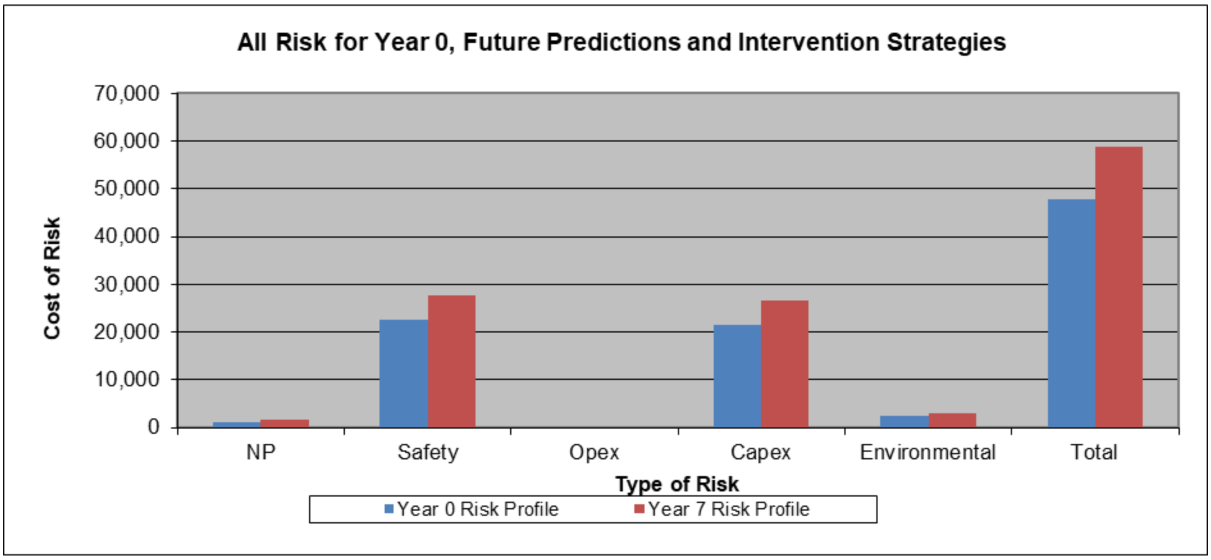
Figure 4-14: Year 7 (2031) Health Index Profile (LV poles)



This result (Figure 4-14) indicates that the majority of the population of LV poles are well below their expected life of 54 years for wood poles and 70 years for concrete poles. Contributors to the total risk cost include Network Reliability, Safety, Operating Expenditure , Capital Expenditure and the Environment. The main factors contributing to the risk to the network should a LV pole fail are Safety and Capex as indicated in Figure 4-15. The LV poles identified as being in poor condition at Year 0 will be monitored by the established pole inspection and testing programs. These will be replaced or reinforced in accordance with JEN's established pole management policies and practices.

In order to maintain the assessed risk associated with the operation of these assets at current (year 0) levels this strategy proposes the replacement or reinstatement of approximately 400 LV poles per annum based on condition over the course of the next 5 year period This is equivalent to a condemnation rate of 0.5% of the LV pole population and less than the current condemnation rate of 0.8%% of the population per year and indicates a reducing trend in pole condemnation based on the health indices of the LV pole population.

Figure 4-15: Risk Profile for Year 0 (2024) and Year 7 (2031), LV poles



4.1.3.3 *Overall Performance*

The condemnation rate for 2022 is 1.4% of the total pole population. The actual number of poles replaced or reinforced during FY21/22 was 1,127 poles or approximately 1.0% of the total pole population and the CBRM forecast number of poles in poor condition for the 2024 year is 969 poles or 0.85% of the total pole population. Further, the CBRM modelling indicates a further reduction in the number of poles classified as in poor condition over the next 5-year period reducing to approximately 0.5% of the total pole population per year.

This apparent disparity between the CBRM model forecasts and the actual condemnation rates and the replacement and reinforcement rates is explained by a few factors:

- Pole condemnation and the associated pole replacement and reinforcement activity is driven by a mature pole inspection and testing program and the year-on-year activity levels can be affected by the zones inspected each year.
- In recent years (2013 to 2021) several additional or extended criteria have been applied to the pole inspection and testing criteria to address identified performance issues. This has included the undersized pole program, changes to the testing criteria for class 3 poles, changes to the management and treatment of limited life poles and changes to the policies around pole reinforcement and pole types in the HBRA. This has resulted in elevated pole replacement and reinforcement rates during this period.

- The above changes have now been in place for a complete 4-year cycle of pole testing and inspection and the associated surge in pole replacement and reinforcement activity driven by the new criteria and programs has passed.

The CBRM model cannot account for the changes in testing criteria and asset replacement policy. It does however assess the overall health of the assets and makes forecasts bases on asset age, sound wood measurements and other modifying factors such as environment. Given that a complete testing and inspection cycle has been implemented with the new inspection criteria the CBRM models forecast that pole condemnation rates and pole replacement and reinforcement activity will reduce and return to levels like those experienced prior to 2013. That is condemnation rates of approximately 0.5% of the total pole population over the next 5-year period.

4.1.4 RISK

4.1.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. An asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is also used to rank importance of dissimilar sub-asset classes (e.g., transformers and surge diverters) to identify areas where risk should be managed first, and control measures implemented.

The poles sub-asset class has an asset criticality score of AC4 (High) due to the consequences for health and safety associated with pole failure or malfunction (for example the fact that concrete poles are conductive and in the event of a fault they can become a step and touch hazard).

The criticality of pole assets located in the HBRA requires that they are given special treatment due to the extreme consequence of asset failure in terms of bush fire start. This is applied to a number of sub-asset classes located in the HBRA to mitigate this risk.

Further issues considered as part of asset criticality analysis include:

- Safety regulations and standards that mandate minimum clearances to ground, between circuits and to other structures for overhead power lines;
- At specific locations the costs may be lower or higher depending on the complexity of the pole top attachments and difficulty in accessing the location (e.g., rail easement);
- The consequence of a pole failure in terms of network reliability varies significantly dependent upon the voltage category. This is because of the number of customers directly effected by the pole failure and the level of network redundancy; and
- When considered from a safety perspective (i.e., in-service pole failure) the voltage category has less impact on the consequences. Every pole failure in the public domain has the potential for serious health and safety consequences for JEN personnel and the general public.

4.1.4.2 *Failure Modes*

Pole failures can be grouped in three categories:

- Physical failure of a pole, where a pole is no longer able to perform its designed function. In this case it can no longer support its own weight and/or support the overhead infrastructure;

- Functional failure of the pole, where it's remaining strength is assessed as being insufficient to safely perform its designed function; and
- Footing failure, where the footing of a pole (i.e., bedlogs or ground condition) does not provide sufficient support to the pole and results in the pole leaning.

Physical failure can be either assisted or unassisted (such as breakage). Assisted failure occurs due to external influences such as:

- Vehicle impact;
- Tree impact; and
- Failure of adjacent pole.

Unassisted failure can be caused by:

- Wood rot – at the ground line, pole top and crossarm mounting points;
- Termites;
- Pole fire caused by insulator tracking;
- Foundation deterioration (leaning poles);
- Corrosion (steel poles & towers); and
- Reinforcement corrosion/concrete cancer (concrete poles)

Footing failure can occur due to:

- Soil conditions; and
- Incorrect installation or design.

All pole failures carry a risk of third-party claims for property damage and/or personal injury. All fire starts also creates an F-factor penalty.

4.1.4.3 *Current Risks*

Risks associated with the management of electricity distribution poles are currently documented in JEN's Compliance and Risk Management System, and reviewed annually.

The current risks associated with poles are:

- *Conductive pole becoming live: C*onductive poles (steel or concrete) in all voltage categories can become 'live' due to mechanical and electrical failure or faulty equipment. The result is hazards associated with step and touch potentials on or around the pole which are a health and safety risk for JEN staff and the general public;
- *Assisted pole failure:* As discussed above assisted pole failure can occur as a result of third party vehicle or tree contact with JEN's poles or overhead lines supported on JEN poles. The consequence of this type of failure can include injury to employees, contractors or the general public, fatality, damage to JEN assets or public property and loss of supply; and
- *Unassisted pole failure (i.e., in-service pole failure):* This type of physical failure of a pole during the asset lifecycle can result in injury to JEN employees, contractors or the general public, fatality, damage to JEN assets and public property and loss of supply.

Poles treated with Copper Chrome Arsenate (CCA) and creosote have the potential to cause environmental harm and harm to people working with these chemicals.

Other risks that need to be considered are listed in in the following sections.

4.1.4.3.1 Undersized Poles

In 2008 a severe windstorm hit Melbourne and especially the northern suburbs with wind gusts recorded at over 120 km/h. JEN sustained 6 pole failures in the storm; 2 were substation poles, 1 was a concrete LV pole brought down by a large tree falling on it and 3 poles were intermediate wood LV poles. These 3 LV poles are in a category termed “undersized” poles. An undersized pole is one where its natural girth (no external decay) is less than the minimum tabulated girth for a Serviceable pole. Until now undersized poles have been allowed to remain in service provided there was sufficient sound wood and no external decay. These poles are no longer standard, and it is estimated they have a life span that is between 10 and 20 years less than a standard 8kN or 12kN pole. It has been decided that all in service undersized distribution poles that demonstrate signs of external decay will be either reinforced or replaced.

Any undersized pole identified as a result of the routine pole and line inspection program is classified US and is replaced or reinforced according to the relevant criteria and priorities. In addition, a specific program is also in place to replace or reinforce undersized poles, so as to address all of these on the network.

4.1.4.3.2 HV Raiser Brackets

Another subset of poles that have been examined in the recent past are the LV poles fitted with HV raiser brackets. These are poles that were designed as LV poles, and sometime after installation, a HV line was added. The HV raisers were likely installed, rather than replacing “new” LV poles with HV poles on the basis of cost. It is arguable the design was acceptable in the past when wood HV arms were standard. The standardisation of the steel HV crossarms has made the use of HV raisers problematic. The issue is, a wood HV crossarm provides additional insulation between the HV and LV circuits, but with a steel arm a situation is created where the raiser bracket could be energised at HV only centimetres from bare LV conductors if a HV insulator is bridged by some airborne debris or a HV tie breaks and the conductor rests on the crossarm. The potential danger is greatest for unsuspecting line workers. To mitigate this risk LV poles with HV raisers are being replaced with standard HV poles when the wood HV crossarm reaches the end of its economic life.

4.1.4.3.3 Process Risks

The corporate systems available for recording pole conditions and characteristics are well structured and cater for the information requirements of many business groups. JEN continuously monitors the databases and systems and seeks to make improvements and rectify issues when they become apparent. To identify areas of improvement, some examples of monitored areas are:

- In any inspection cycle, the zone completion needs to be managed to ensure all poles are inspected and appropriate records kept; and
- In some situations, inspections and characteristics are recorded on paper forms or Line Inspection Reports (LIR). This paper trail needs to be managed and cross-referenced carefully to prevent multiple inspections of the same pole or the missing of a scheduled or due inspection.

4.1.4.4 *Existing Controls*

To mitigate the likelihood and consequence of these risks, assets are regularly inspected and assessed in order to maintain a high degree of confidence in the structural integrity and safety of the pole population.

JEN's standards, procedures and management plans are key controls in reducing the likelihood of these events occurring. JEN's internal technical standards and design and construction manuals are intended to ensure all assets on the JEN network are fit for purpose and comply to the relevant design standards. Incident investigations are conducted to determine the root cause of an asset failure. In particular this applies to all in-service unassisted pole failures. The findings of these investigations are reviewed, and actions put in place to prevent incidents from re-occurring.

Field staff attend regular training to ensure they are competent and aware of hazards that may be associated with these risks. For example, for the risk of a conductive pole becoming live. Field staff attend regular specific training, such as the Victorian Electricity Supply Industry (VESI) training module "Live Low Voltage" which covers the hazards and precautions associated with working on conductive poles.

4.1.4.5 *Future and Emerging Risks*

The risks associated with the sub-asset class are forecast to remain relatively high in the near future. However, the proportion of poles reaching the wear-out zone and observed condemnation rates indicate increased replacement volumes may be a risk in the future. An analysis of pole condition during its wear-out phase is discussed in detail in the Performance Section (4.1.3).

An emerging risk for this sub-asset class is an increasing condemnation rate of steel poles (public lighting) due to faster than expected corrosion rates. Revised pole footing wall thickness requirements have been included in the P/L steel pole specification to mitigate this issue.

JEN's technology strategy involves investigating new technologies to maintain network reliability and reduce costs. Future improvements could be made in the data capture area relating to real-time systems and advanced capability for automatic data validation to mitigate some of the issues described in later sections.

4.1.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The preferred asset lifecycle management option involves condition based risk management. With the exception of project based pole replacement, all poles are operated based on their assessed condition. The Asset Inspection Manual (AIM) specifies condition criteria for all pole materials. Management of poles occasionally changes based on the investigation of failed poles. Examples of such changes include the management of undersized poles, or reinforcing existing criteria as was the case for sound wood measurement for Class 3 poles.

It is always more cost effective for an overhead network to remain overhead, therefore undergrounding will not be considered as a poles sub-asset class lifecycle management option. Undergrounding may be considered for other policy or project reasons.

Run to failure is generally not considered as a lifecycle management strategy especially on assets which are not fail safe. This type of lifecycle management stratey is typically employed on low cost/high volume and consumable assets (such as public lighting lamps), in which the consequence of failure is low; and spare asset and staff resources, including network response to resultant outages or replacement activity can be promptly addressed at relatively low cost.

4.1.5.1 *Creation*

New poles in this asset class are effectively created via new projects associated with the connection of new network load or the augmentation of network capacity and by the replacement of existing poles.

The principals that are applied to the creation of new pole assets include:

- In the LBRA a pole will only be replaced if it is unsuitable for reinforcement. In the HBRA however, a pole is always replaced when it is classified as having a limited life or as unserviceable;
- Poles that have a girth of less than 720mm at 1m above ground are unsuitable for reinforcement (nails are not manufactured to fit such narrow poles). These poles will be scheduled for replacement when identified;
- When a HV wood crossarm mounted on a raiser bracket reaches the end of its economic life the LV pole that it is mounted on will be replaced with the current standard HV pole;
- All poles are supplied in accordance with JEN's material specifications and installed in accordance with JEN Design and Construction Standards. These include:
  - Overhead Line Design Manual – ELE 999 OM DN 001;
  - Distribution Construction Manual - ELE 999 OM CN 001;
  - Public Lighting Technical Standard – JEN PR 0026
- All Class 1 and 2 wood poles purchased today are Copper Chrome Arsenate (CCA) treated. Historically creosote impregnation was the treatment used and a significant population of this type of pole are currently in service. Creosote is a known carcinogen and consequently its use ceased in the 1980's. CCA has fewer personal and environmental risks associated with it use.
- All public lighting poles are steel;
- All substation poles are concrete; and
- The standard distribution pole in the LBRA is timber
- The standard distribution pole in the HBRA is concrete.

4.1.5.2 *Asset Operation and Maintenance*

There are three (3) life cycle management strategies applied to the operation and maintenance of the poles sub-asset class:

- Condition Monitoring – Asset Inspection and Testing;
- Preventative Maintenance - Treatment; and
- Reactive and Corrective Maintenance.

Time based replacement and replacement through projects are not considered as suitable life cycle options for all pole sub-asset classes. Time based replacements are considered to be costly and unreliable. Instead, replacement based on asset condition is the most efficient use of resources as it focuses on assets that require attention. For example, if a time based approach was used for pole replacement, poles would be replaced at a pre-determined age which would lead to increased rates of in-service failures or poles being replaced with a significant amount of residual life. Hence this life cycle management option is not appropriate.

The replacement of poles through projects is not considered because this activity replaces poles for customer-initiated projects and third-party impacts, mostly vehicle impacts or an occasional failed tree impact. Although this activity does influence pole statistics, it is not a lifecycle management option.

4.1.5.2.1 Condition Monitoring - Asset Inspection and Testing

The poles sub-asset class is inspected routinely as described below. The asset condition assessment criteria includes measurement of internal rot and pole girth. The average sound wood criteria for serviceable, limited life and unserviceable classifications is set out in Chapter 4 of the AIM. Various inspection criteria including inspection cycles are regulated via the Electricity Safety (Bushfire

Mitigation) Regulations, e.g., regulation 7(1)(i) for inspection intervals. Full details of asset inspection operations, including wood pole preservative application, are contained in the AIM.

Inspections shall identify, verify and record all poles regardless of type. The corporate systems (e.g., GIS and SAP) are the repository of all asset information and the defined business processes will be adhered to for field data capture. The data to be verified and captured is detailed in the AIM.

4.1.5.2.1.1 Inspection Cycle

The maximum inspection cycles have been mandated by ESV through the Electricity Safety (Bushfire Mitigation) Regulations. These regulations require that in the HBRA the maximum period between subsequent inspections cycle is no more than 37 months and no more than 61 months in the LBRA. This applies for all electricity distribution sub-asset classes.

The inspection of steel public lighting (P/L) poles is a special subset of pole inspection and is therefore addressed in a separate strategy. The inspection of these assets is covered in the Public Lighting ACS.

Routine inspection intervals including initial inspections, for poles made from various materials are detailed in the AIM. In the order of 25,000 to 35,000 poles are inspected each year. Below is a summary of pole inspection cycles based on their location:

- *For Low Bushfire Risk Areas (LBRA) Network Poles*
  - 4 year cycle, with no pole exceeding 61 months
  - Annual reinspection for limited life poles that cannot be reinforced
- *HBRA Network Poles*
  - 3 year cycle, with no pole exceeding 37 months

Inspection cycles for poles based on classification are as follows:

- **Sub-transmission Poles:** Poles on sub-transmission feeders (66kV and 22kV), with or without subsidiary distribution feeders, are inspected in accordance with their own SAP maintenance plan.
- **Distribution Poles:** Distribution poles including HV/LV mains, public lighting, other distribution businesses, POELs, other owners (e.g., Telstra, Vic Track, Tramways, etc.) and service poles are divided into areas called inspection zones. The zone boundaries are designed to follow distribution boundaries, designated HBRA boundaries and, where possible, geographic features like major roads or rivers/creeks. Each inspection zone contains approximately 2,000 poles, and a few zones contain more than 4,000 poles. Maintenance plans in SAP define the inspection cycle for each inspection zone and sub-transmission feeder.
- **Steel Lattice Towers:** JEN owns 23 towers. These towers are inspected on a 5-year cycle in accordance with their own SAP maintenance plan.
- **Public Lighting Poles:** All wood, steel and concrete public lighting poles which are serviced overhead are inspected at the same time as the distribution poles in each inspection zone.
- **Limited Life Poles:** Limited Life (LL) poles that cannot be reinforced in the LBRA are either replaced or routinely re-tested each year until they are reclassified as Unserviceable. Limited life poles located in the HBRA are scheduled for replacement with a concrete pole.

In the LBRA, when a pole is assessed as LL for the first time, it is reinforced if assessed suitable. LL poles in the LBRA that are unsuitable for reinforcement are either replaced or added to the current list of LL poles inspected annually in accordance with their own SAP maintenance plan. Some reasons that a LL pole may not be suitable for reinforcement include insufficient amount of sound wood at a metre above ground level, unsuitable attachment points, and obstruction because of underground assets.

4.1.5.2.1.2 Inspection methods

A well-developed and long-standing AIM specifies the criteria for the condition assessment of wood, concrete, and steel poles. This is a time-based activity, and a high-level summary is provided here for each pole material.

This option allows for an effective condition based management system to be employed. This minimises the number of in-service failures and, replacement of healthy poles when compared with a time based lifecycle management system.

For wood poles inspection may involve (the actual tests performed are determined by the pole age and/or condition):

- Digging around the base to check for external decay and evidence of termites;
- Bore into the pole at the ground line to assess remaining sound wood (i.e., not decayed/rotted);
- Bore into the pole at the ground line to add pole-saver rods. This is a chalk-like compound of Boron and Fluorine used as a fungicide and decay inhibitor;
- Measure the pole girth at the point of maximum decay. This measurement contributes to determining the condition. The girth at 1m is measured and in conjunction with the nameplate strength the pole may be targeted by the undersized poles program;
- Sound the pole. The pole is struck with a hammer for the asset inspector to listen for hollow sounds which may indicate the presence of internal voids created be decay or termites;
- Limited Life poles are bored at 1m to determine if sufficient sound wood exists to attach a stake;
- Visual inspection all around the pole from ground to top. Defects (e.g., from unreported vehicle impacts), decay and termite activity are sometimes observed. Pole top rot is almost non-existent due to the application of pole caps. Inspection and treatment are coincident activities to capitalise on a single visit; and
- All reinforced wooden poles only require limited excavation around the pole base to check for rust and termite attack. Testing and treatment are carried out at 1m above ground level.

For Concrete poles inspection involves visual inspection all around the pole from ground to top. Defects (e.g., from unreported vehicle impacts) may cause the steel reinforcement to be exposed resulting in concrete degradation.

For Steel poles, inspection involves digging around the base to check for the extent of external corrosion and visual inspection all around the pole from ground to top. Defects (e.g., from unreported vehicle impacts) may cause frangible poles to become unstable or protective coatings to be damaged, exacerbating above-ground corrosion. Vandalised access covers are also identified from time to time

4.1.5.2.1.3 Private Overhead Electric Line (POEL) Poles

In an effort to satisfy the requirements contained in the Electricity Safety (Bushfire Mitigation) Regulations 2013, JEN inspects POELs in the HBRA on a 3 year cycle and LBRA on a 4 year cycle in accordance with Regulation 9.

The inspection holes and treatment holes in these poles are treated with wood preservative (Polesaver rods). Leaning poles shall be identified as per definition of leaning poles in the AIM.

Regulation 10 prescribes the standard of inspection to be applied to a POEL and there is no LL criteria applied to private poles; once these limits are reached the pole is deemed Unserviceable. No inspection holes are drilled in CCA treated pine poles to ensure the CCA treatment remains effective. For a detailed list of inspection criteria applied to POELs refer to Chapter 9 in the AIM.

4.1.5.2.2 Preventative Maintenance - Treatment

Preventative maintenance of the poles sub-asset class is focussed on the prevention or slowing of the ageing and deterioration of timber structures. This section describes the preservative treatments used on distribution timber poles to treat and prevent timber rot.

Poles are, on average, about 12 metres long, but the most important part of each wood pole (from a timber condition perspective) is the 300mm below and 100mm above ground level. Careful treatment of the pole with internal wood preservatives at and below the ground line is carried out to extend the life of wood poles. Refer to Chapter 5 of the Asset Inspection Manual (AIM) for full detail on the chemical treatment and its application.

All wooden poles are treated with Polesaver rods in conjunction with each inspection cycle. Treatment commences as detailed in Chapter 4, Table 4.2 of the AIM then continues at each inspection cycle in accordance with Chapter 4 of the AIM. Polesaver rods are placed in treatment holes and provide a 3 to 5 year protection period against all forms of wood rot and deter termites from attacking the treated wood. These treatments have had a significant impact on the rate at which timber poles age and deteriorate.

The same treatments are applied to reinforced poles to slow the above ground deterioration of the pole.

4.1.5.2.3 Reactive and Corrective Maintenance

Corrective Maintenance is reported and monitored in monthly maintenance and activity meetings. The Bushfire Mitigation Index is also produced monthly to monitor maintenance activities in the JEN HBRA. These indices are a progressive measure of the achievement of business targets for critical activities in the Bushfire Mitigation, Asset Inspections and Preventive Maintenance programs.

Reactive and corrective maintenance is undertaken when faults occur or after inspection has identified a defect (or both). Reactive and corrective maintenance activities include the following:

- Treatment for Termite Infestation - Termite infestation of wood poles occasionally occurs and is readily identified by the inspection process. Termite treatment is carried out in accordance with the requirements of the AIM;
- Correcting Leaning Poles - Leaning poles are poles that:
    - Lean more than 5 degrees from the perpendicular centreline of the pole and the pole leans over the kerb line in the direction of a vehicular carriageway; or
    - Lean more than 10 degrees from the perpendicular centreline of the pole elsewhere.

  Any pole found to be leaning as per the definition above will be rectified as required by the Electricity Safety (Network Assets) Regulations 1999 and documented in the AIM (table 12 of chapter 4).
- Missing Pole Caps – The top of the pole is cut at a right angle against the natural grain of the timber. Without a pole cap, the pole top is exposed, which may lead to severe pole top rot. Any missing or dislodged pole caps will be identified by inspection and rectified as required;
- Pole Top Rot - Pole Top Rot (PTR) is a significant issue for all wood poles. Pole caps have proven to be effective in the prevention of PTR and are maintained in line with the inspection program. If an assessment deems the pole top is likely to fail before the next scheduled inspection, the pole will be replaced within the notification priority time frame;

- Refurbishment (Pole Reinforcement) - Unserviceable poles must be actioned within 12 weeks of identification. When a wood pole is assessed as LL or US the first option is to assess its suitability for reinforcement. The pole will either be reinforcement (if suitable) or replaced considering mechanical loading, wood condition at reinforcement height and above, pole top rot or termite infestation. The suitability for reinforcement criteria is detailed in the AIM but generally includes available sound wood at 1m, sufficient space on the pole, clear of underground assets at the pole base, type of pole structure (e.g., some undersize poles or LV poles with nonstandard HV raiser brackets will not be reinforced) and access to the pole with the reinforcement machinery/tools (i.e., difficult terrain). It is estimated that pole life is extended at least 20 years after being reinforced; and
- Undersized poles (as mentioned in section 4.1.4.3.1) will be addressed as a program of work and as they are identified.

4.1.5.2.3.1 Fault response strategy

Corrective maintenance prioritisation and timeframes include the following:

- Treatment for Termite Infestation – within 4 weeks of assessment;
- Correcting Leaning Poles – depending on the severity of the lean, between 12 weeks and 12 months of assessment;
- Missing Pole Caps – within 6 months of assessment; and
- Refurbishment (Pole Reinforcement) – within 12 weeks of assessment

The fault response strategy for this asset class involves replacement of the damaged pole. When a wood, concrete or steel pole fails (for any reason) it cannot be repaired (e.g., by reinforcement) making replacement necessary in every case.

All poles assessed as Serviceable and identified with failed footings, i.e., leaning more than 5 to 10 degrees may be straightened by under-digging and/or installing a bed log (wood and concrete poles only).

As the stake is not attached to the pole butt (footing) reinforced poles identified with excessive leans must be replaced.

4.1.5.2.3.2 Predictive maintenance / on condition maintenance

The need for Pole and Pole Top maintenance is determined by the asset inspection process and any work carried out beyond inspection and treatment (by the asset inspector) should, except in the case of minor maintenance or third party accident damage, be carried out as a direct result of raised Notifications or inspection reports. Minor maintenance as defined in the AIM (e.g., installation/repair of guy warning tubes, earth cover strips, cable guards, etc.) will be performed by the Asset Inspector and details recorded in a Notification. Notifications will also be created for maintenance after faults (e.g., pole top fires, lightning strike, etc.). As part of the pole routine asset inspection program the AIM requires the asset inspector to perform minor maintenance work when identified. Chapter 17 in the AIM provides detailed information on the application of this requirement.

JEN has implemented the Reliability-Centred Maintenance strategy for the management of all network assets. Wood and steel poles and some remote-controlled gas-filled switchgear on the distribution network are unique in that physical measurements are taken or reported to assess their condition; all other distribution assets are assessed by visual examination. As a form of condition-based monitoring, visual assessments (of distribution assets other than poles) have matured to a point where reliable conditions are obtained.

4.1.5.3 *Asset Replacement*

All pole types are either replaced or reinforced, following pole inspection and testing once their condition has been classified as Unserviceable (US). Only wooden poles can be reinforced via the installation of pole stakes and then only those wooden poles that satisfy the reinforcement criteria.

Undersized poles are also replaced if they are not suitable for reinforcement via the reinforcement option. When LV poles with HV raiser brackets are assessed as US they are replaced with HV poles. These poles are also required to be replaced when the HV wood crossarm is identified as unserviceable (due to the unacceptable separation between HV and LV if a steel HV crossarm were to be installed).

4.1.5.3.1 Pole Replacement and Reinforcement - Forecast Volumes

As detailed in this strategy, a number of pole replacement or reinforcement projects have been identified to ensure the maintenance of network performance, and address our compliance requirements. These are included in the forecast volumes in Table 4-10.

Table 4-10: Poles Replacement and Reinforcement – Forecast Volumes

Unique ID	Service Code	Poles	Replacement Volumes – Poles						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A166	RPH	Pole Repl. (Incl. Pole Top) - HV	178	182	194	194	194	194	194
A170	RPL	Pole Repl. (Incl. Pole Top) - LV	156	158	168	168	168	168	168
A171	RPS	Pole Repl. (Incl. Pole Top) - ST	8	8	14	15	15	15	15
A32	RRH	Pole Reinforcement - HV	207	235	205	220	220	220	220
A175	RRL	Pole Reinforcement - LV	376	376	376	376	376	376	376
A177	RRS	Pole Reinforcement - ST	38	31	25	25	25	25	25
A477	RPH	Undersize Pole Replacement	-	-	12	26	26	26	26
A480	RRH	Undersize Pole Reinforcement	-	-	50	104	104	104	104
A528	RPH	Pole Replacement - Replacement of Reinforced Poles - HV	-	-	49	109	109	109	109
A534	RPS	Pole Replacement - Replacement of Reinforced Poles - ST	-	-	12	27	27	27	27
A535	RPH	Pole Replacement - Replacement of Limited Life Poles Unsuitable for Reinforcement – HV	-	-	29	63	63	63	63
A536	RPL	Pole Replacement - Replacement of Limited Life Poles Unsuitable for Reinforcement - LV	-	-	25	54	54	54	54
A537	RPS	Pole Replacement - Replacement of Limited Life Poles Unsuitable for Reinforcement - ST	-	-	2	5	5	5	5

4.1.5.4 *Asset disposal*

Untreated poles are generally diverted to landfill or recycled.

CCA and creosote treated poles contain chemicals and have a different disposal process to untreated poles. Treated poles should not be used for any other purposes that create health risks to employees or the general public, for example – treated wood should not be reused as firewood. A trial has been undertaken involving the removal of the contaminated layer from the treated pole and the repurposing of the wood for furniture.

It is preferable treated poles are reused within the community. In the case where a treated pole cannot be safely reused it must be appropriately disposed to landfill in accordance with EPA requirements. For more information on CCA management and handling refer to JAA HSE GU 0008 Managing Treated Timber Poles.

4.1.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.1.5.6 *Spares*

Spares requirements for critical assets are assessed by following the Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). Spares for the range of pole types and sizes are maintained at Tullamarine depot and stock holdings are managed.

Common pole sizes are turned over regularly and stocks are maintained to service this need which also covers the need for unplanned and emergency replacements. Due to the long lead times associated with the sourcing of poles a stock of poles of less common lengths such as 15m and 17m is maintained.

Although very few poles fail "in-service" a stock is kept for poles damaged by vehicle impact (approximately 170 poles per annum are replaced due to vehicular impact and the majority of these are public lighting poles). Pole replacements due to vehicle impacts are treated as recoverable works and as such are not included in forecast replacement numbers associated with the end of life replacements and reinstatements.

Furthermore, when assets are retired from service consideration is given to retaining components or the entire asset (after refurbishment) as spares to service existing aging assets.

4.1.6 INFORMATION

JEN uses a number of systems to ensure that network assets are operated in a safe manner that is consistent with their ratings and operating environment. Principal among these is the System Control and Data Acquisition System (SCADA) operated by the Control and Dispatch Centre of Network Operations within Electricity . This system is used to manage the Sub-transmission and High Voltage networks. The Low Voltage network and associated assets are managed using data sources and systems which are collectively referred to as Business Intelligence (BI). The principle data used is the smart meter (AMI) energy consumption data and data on connectivity contained in the Graphical Information System (GIS). This allows the compilation of loading information on the various elements of the LV network from substations down to LV services. It also provides data on supply quality parameters.

Information required to support asset strategies, performance and risks is recorded in SAP, GIS and the Enterprise Content Management System (ECMS). Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

GIS is used to capture all the characteristic information about a pole and its location. This includes information like length, strength, owner, other attached or supported assets, geographic location, age, inspection zone, fire danger area, declared vegetation zone and so on. All JEN owned poles are identified with an "A" number and all private poles where JEN is responsible for inspection are marked with a "P" number. The pole is classified automatically in GIS by the voltage of the lines attached. The functional location of the highest voltage line supported is automatically assigned to the pole.

The AIM specifies which assets to assess and the relevant condition criteria for an accurate assessment of the pole's condition to be made. SAP defines how this information is to be recorded.

SAP is used to capture for example; pole condition assessment records, defect Notifications, PM Orders, labour and material costs, maintenance plans etc. The list is extensive but can generally be categorised as condition information or lifecycle management information. SAP is also used to record specifications for each pole type which has been agreed with the vendor, whose details are also recorded in SAP.

Pole inspection and characteristic information is recorded in the field by the asset inspector on a field computer. The records captured each week by each inspector are transferred to JEN. GIS Data Capture staff validate the data and upload it to GIS and SAP.

Photographs of the assets and poles, taken by the asset inspectors, are also transferred to JEN weekly where GIS Data Capture staff link each photo to the relevant equipment in GIS. Photos of defects are linked to Notifications.

JEN's AMS provides a hierarchical approach to understanding the information requirement to achieve JEN's business objectives at the Asset Class. The ACS provides the context for and determines the information required to deliver an Asset Class business objectives.

From these business objectives, it is possible to identify at a high-level the content of the business information systems' required to support these objectives (

Table 4-11).

Table 4-11: Poles sub-asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table **4-12** identifies the current and future information requirements to support the Asset Class critical decisions and their value to the Asset Class.

Table 4-12: Poles sub-asset Class Critical Business Decisions Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Pole Acquisition and Application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied poles and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing / historical) - Status (in service, isolated, out of commission) - Operating voltage - Pole number (A-number) - Pole Type (distribution, public lighting etc.) - Material - Classification - Length - Strength - Disc Year - Date Installed - Timber Treatment - Owner • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Enhanced inspection data quantities such as: • Drill hole score • Type of Rot • Photo database of failed assets • Girth ratio (below ground / above ground • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-13 details the information initiatives required to provide for the future information requirements identified in

Table **4-12**. Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-13: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improved Asset Attributes	Review current asset attribution fields to ensure attributes being collected are asset specific.	Medium	Appropriate and Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

The relevant metrics used to measure data quality for all sub-asset classes are defined below:

- **Currency:** Concerned with attribution values that are up to date with respect to their actual value in the real world. For example, if a pole is replaced in the field, the databases (GIS and SAP) need to reflect this change within a timely manner. During each pole inspection the asset inspector is instructed to confirm the pole data is up to date. To be able to quantify currency, an additional field will need to be added for field inspectors to confirm they have "checked data".
- **Completeness:** This is a measure on the totality of the pole characteristic data set. To measure the completeness of data a sample of approximately 100,000 poles was used. From this sample the percentage of completeness represents the number of unknown values relative to the sample size.

Table 4-14 below indicates the accuracy of pole data characteristics for a sample of pole characteristics.

- **Consistency:** Is a measure of the consistent delivery of a business requirement. For example, all private poles have a "P" number, and all JEN poles have an "A" number.
- **Accuracy:** This would typically require a field audit to confirm data the database and the field are the same. To ensure the accuracy of current and future data, validation audits should be conducted to confirm the accuracy and currency of the information in the field and database.

Table 4-14 indicates the completeness and consistency of particular pole data characteristics. To calculate completeness a sample of 100,000 poles was used. The completeness metric is a measure of the number of unknown values for that pole characteristic relative to the total population of poles. The results in Table 4-14 show the completeness of information for poles is near 100%.

Table 4-14: Data quality metrics for Poles

Pole Metric	Completeness
Pole number (A-number)	98.61%
Material	100.00%
Species	98.99%
Length	99.89%
Strength	99.47%
Date installed	Approx. 99.00% Majority of install dates for poles pre 1960 were based on estimated installation date.

The below table outlines the JEN safety factors for JEN poles that references the AS7000. The factors recorded below identifies the multiplication factor for poles under the following conditions: serviceable, limited life (LL), New Unserviceable (US) Pole condition (PC) only and Unserviceable (US).

Table 4-15: JEN Safety Factors for Poles by Pole Condition

Condition	Strength reduction (%)	Safety factor PC	Safety factor JEN
Serviceable	0	2.5	2
Limited Life	0.25	1.875	1.5
New Unserviceable – PC Only	0.44	1.4	
Unserviceable	0.5	1.25	1

4.2 POLE TOP STRUCTURES SUB-ASSET CLASS

4.2.1 INTRODUCTION

The pole top structures sub-asset class includes crossarms, insulators, insulator ties, braces, bird covers and bolts. The main focus of this sub-asset class is crossarms.

Crossarms are categorised by two main types; Low Voltage (LV) wooden types and High Voltage (HV) or sub-transmission (ST) normally steel.

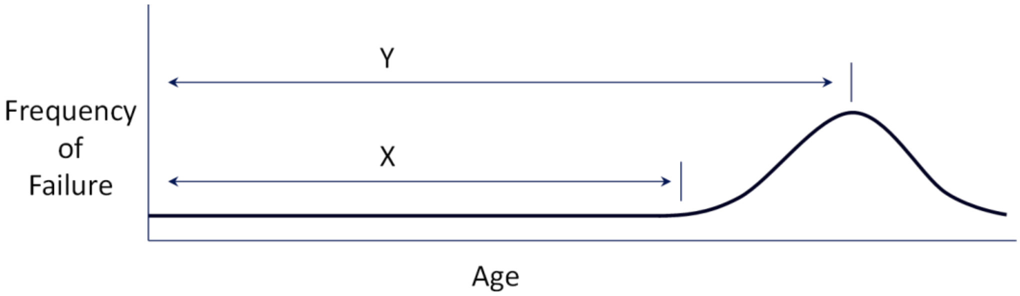
- The HV and ST crossarms are interchangeable i.e., the same arm type (e.g., SL24) can be used to support both HV or ST conductors however the actual choice of a crossarm type is dependent upon the conductor loads (stringing tensions) and the required conductor separation. All new HV and ST crossarms installed since the mid ‘90’s have been made from galvanised steel. HV and ST wood crossarms are susceptible to Pole Top Fires (PTF) however un-bonded steel crossarms installed on wood poles have been known to result in PTF’s. All ST and HV crossarms in the HBRA are steel. In the LBRA, HV and ST crossarms are progressively being replaced with steel crossarms through the pole top fire mitigation program and proactive condition based maintenance replacement.
- LV crossarms that support open wire mains are always made from wood. This is an important safety feature for open wire circuits from a “Live” works practices perspective.
- Suspension brackets for LV ABC are recorded as steel LV crossarms in the asset data systems and there are about 26,500 of these on JEN.
- There are approximately 1,800 wood CATV buck-arms installed on substation poles that are in addition to the LV wood pole population.
- There are approximately 59,000 LV wood crossarms, 7,300 HV wood crossarms, and 39,000 HV steel crossarms as indicated in Table 4-16.

4.2.2 ASSET PROFILE

4.2.2.1 *Life Expectancy*

Pole Top Structures display a wear-out characteristic of the type indicated in the figure below. The onset of wear out occurs at the end of the useful life, and failure follows a normal distribution after the useful life. This overall failure behaviour is depicted in Figure 4-16.

Figure 4-16: Graph of assumed pole top structure life



The useful (average) life expectancy (Y) of a wood crossarm is 45 years. The useful (average) life expectancy for steel crossarm is 70 years. X is the expected life with a low probability of failure. The difference between average life expectancy (Y) and expected life (X) is the remaining life span in which the crossarm has, on average, an increased probability of failure (Table 4-16).

As per, ELE PR 0012 Network Asset Useful Lives Procedure it is estimated that most poles older than 45 years will have had the crossarms changed at least once. It is generally accepted that all ST and HV crossarms installed after 1980 are steel. The table below suggests the majority of HV and ST crossarms are now steel.

Table 4-16: Crossarm Life Expectancy and Quantities

Crossarm Type	Pre 1980	1980 to present	Total	Useful Life 'Y'	Span Y-X
Wood ST crossarms	253	112	365	45	10
Wood HV crossarms	3,096	4,219	7315	45	10
Wood LV crossarms	19,926	38,873	58,799	45	10
Total Wood	**23,275**	**43,204**	**66,479**		
Steel ST crossarms	137	8,776	8,913	70	10
Steel HV crossarms	3103	35,965	39,068	70	10
Total Steel	**3,240**	**44,741**	**47,981**		
Total Crossarms	**26,515**	**87,945**	**114,460**		

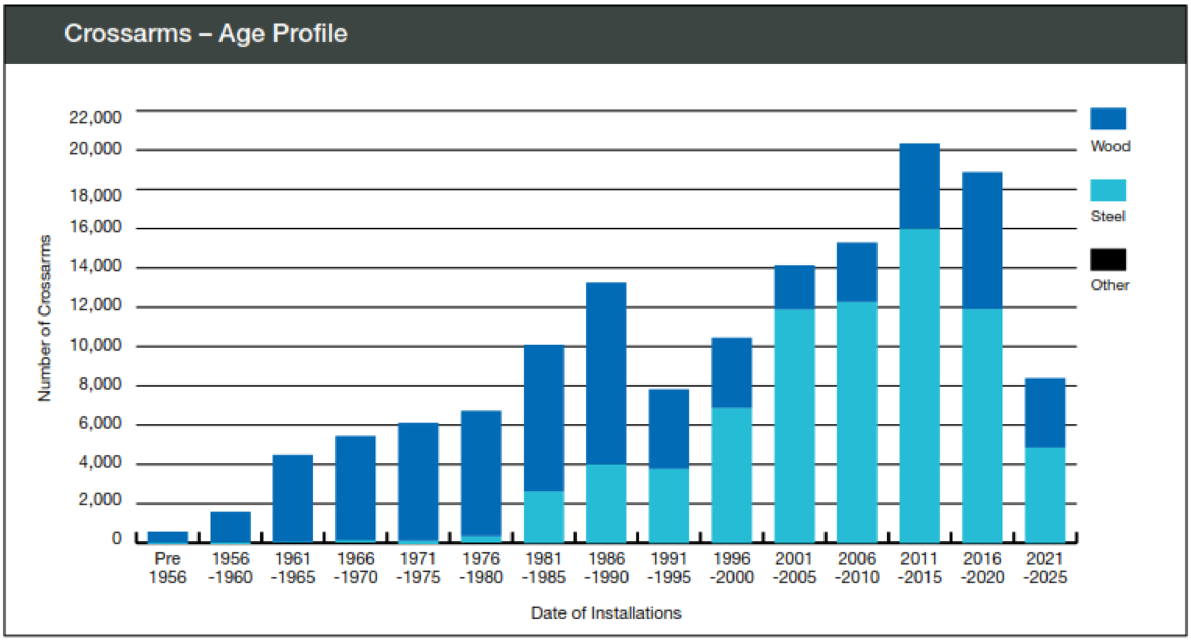
4.2.2.2 *Age Profile*

Due to the lack of accurate data relating to crossarm and insulator age, significant effort has been made to estimate this age profile. This involved accurately determining the age of adjacent assets such as poles and conductor.

The age profile (Figure 4-17) has been developed based on the following assumptions:

- Steel crossarms are likely younger than the supporting pole and unlikely to have been installed prior to the mid '70's;
- While it is likely that HV wood crossarms installed prior to 1969 have been replaced, in the absence of any alternate positive references, the age of the crossarm is assumed to closely relate to the pole age;
- The use of wood HV and ST crossarms ceased post privatisation (Oct 1994); and
- The use of LV ABC has significantly accelerated since privatisation. Due to the reduced tree clearance space requirements LV ABC is encouraged by the regulator and preferred by councils and customers.

Figure 4-17: Pole Top Structures Age Profile



The pole top structure age profile is based on crossarm age data and covers a broad timespan. It is assumed that the bulk of older pole assets dating back to the 1920's have had their Pole Top Structures replaced at least once in the last forty years. The majority of the assets were constructed by the State Electricity Commission and Municipal Electricity Undertakings with asset types ranging from wooden crossarms fitted with porcelain or glass insulators through to steel crossarms fitted with polymeric insulators.

The total volume of LV ABC support brackets and LV wood crossarms demonstrate the consistently high volume of work required on the LV reticulation circuits. As indicated in Figure 4-17, any LV timber crossarms installed prior to 1977 has exceeded the expected average wood crossarm life of 45 years. There are more than 21,000 crossarms (both steel and wood) over the age of 45 years.

The population of LV ABC brackets is relatively young, with a large proportion of LV ABC brackets (LV steel crossarms) being installed post 1990. Consequently, deterioration or failures of this population over the next 20 years is not expected.

4.2.2.3 *Utilisation*

Pole top structures are used to support both bare and insulated overhead HV and LV distribution networks and to support and insulate the overhead sub transmission network.

Pole top structures used to support the bare or air insulated overhead distribution and sub transmission networks are comprised of passive devices such as crossarms, insulators, insulator ties, braces, bird covers and bolts. These provide the structural support and the insulation of the bare conductor overhead networks. Similarly pole top structures that support insulated cable systems such as LV ABC are comprised of suspension brackets, strain brackets and bolts. These provide the structural support of the cable system and protect the cable insulation.

4.2.3 PERFORMANCE

4.2.3.1 *Requirements*

The principal function of a pole top structure and its associated components is the structural support and insulation of the conducting components of the overhead distribution network. To this end they are designed and configured to ensure the required phase to phase separation, ground clearances and clearances to adjacent structures are achieved and maintained under all operating conditions and for the design life of the asset. This includes the maintenance of the required insulation withstand strength and impulse strength in all weather conditions.

Pole top structures are also designed and constructed to address known factors that can impact on network performance and reliability. These include:

- Structural design that accounts for conductor loads and maximum stringing tensions;
- Wind loads and conductor vibration issues;
- Conductor clashing due to the passage of fault current and the effect of high winds and tree movement;
- The mitigation and elimination of pole top fires;
- The mitigation of bird and animal strikes on pole top structures; and
- The safe maintenance and construction of pole tops using conventional and live line techniques.

The requirements for pole top assemblies are set out in the following JEN standards:

- Overhead Line Design Manual – ELE 999 OM DN 001 (previously JEN MA 0005); and
- Distribution Construction Manual – ELE 999 OM CN 001 (previously JEN MA 0006);

In addition, there are three principal material specifications that define the requirements for these assets. These are the:

- wood crossarm specification;
- steel crossarm specification; and
- insulator specification.

Each of these specifications reference a number of Australian Standards and the principal of these are listed in Table 4-17:

Table 4-17: Pole Top Assemblies - Relevant Australian Standards

Standard	Title
AS 2878	Timber Classification into Strength Groups
AS/NZS 1148	Timber - Nomenclature - Australian, New Zealand and imported species
AS 3818.1	Timber-Heavy structural products-Visually graded, Part 1: General requirements
AS 3818.4	Timber-Heavy structural products-Visually graded, Part 4: Cross-arms for overhead lines
AS/NZS 2947.1	Insulators - Porcelain and Glass for Overhead Power lines - Voltages greater than 1000 Test Methods – Individual units
AS/NZS 2947.4	Insulators - Porcelain and Glass for Overhead Power lines – Voltages greater than 1000 Test Methods – Insulator Strings and Insulator Sets

Standard	Title
AS 3608	Insulators - Porcelain and Glass, Pin and Shackle Type - Voltages not exceeding 1000
AS 3609	Insulators - Porcelain Stay Type - Voltages greater than 1000 V AC
AS 4398.1	Insulators, Ceramic or Glass - Station post for indoor and outdoor use. Voltages greater than 1000 V AC – Characteristics
AS/NZS 4680	Hot Dipped Galvanized (Zinc) Coatings on Ferrous Articles
AS 1074	Steel Tubes and Tubulars for Ordinary Service
AS/NZ 1163	Cold-formed Structural Steel Hollow Sections

4.2.3.2 *Assessment*

The assessment of the performance of this sub-asset class is based on the following criteria and measures:

- Crossarm failure rates or breakdown frequency;
- The monitoring of the timely completion of corrective maintenance tasks (notifications) via the asset maintenance monthly reports;
- The monitoring of the Bushfire Mitigation Index; and
- CBRM generated health indexes.

4.2.3.2.1 The Breakdown Frequency

The breakdown frequencies for pole top structures are monitored on a monthly basis. The data for the measurement of breakdown frequency is derived from data recorded as fault notifications and extracted from SAP. This data is monitored for increased failure trends which may indicate possible strategic deficiencies.

A pole top structure breakdown is defined as the in-service failure of the crossarm, conductor supporting brackets or insulator system resulting in the failure of the structure to support or provide insulation of the electrical conductors. Pole top structure failure modes are discussed in detail in Section 4.2.4.2.

As shown in Table 4-18, the number of pole top structure breakdowns occurring on an annual basis is variable with an average of around 27 per annum. A minor peak occurred in 2011 due to adverse weather patterns. This data only considers in service crossarm failures and includes crossarm failures caused by pole top fires.

Table 4-18: Pole Top Structure Breakdown

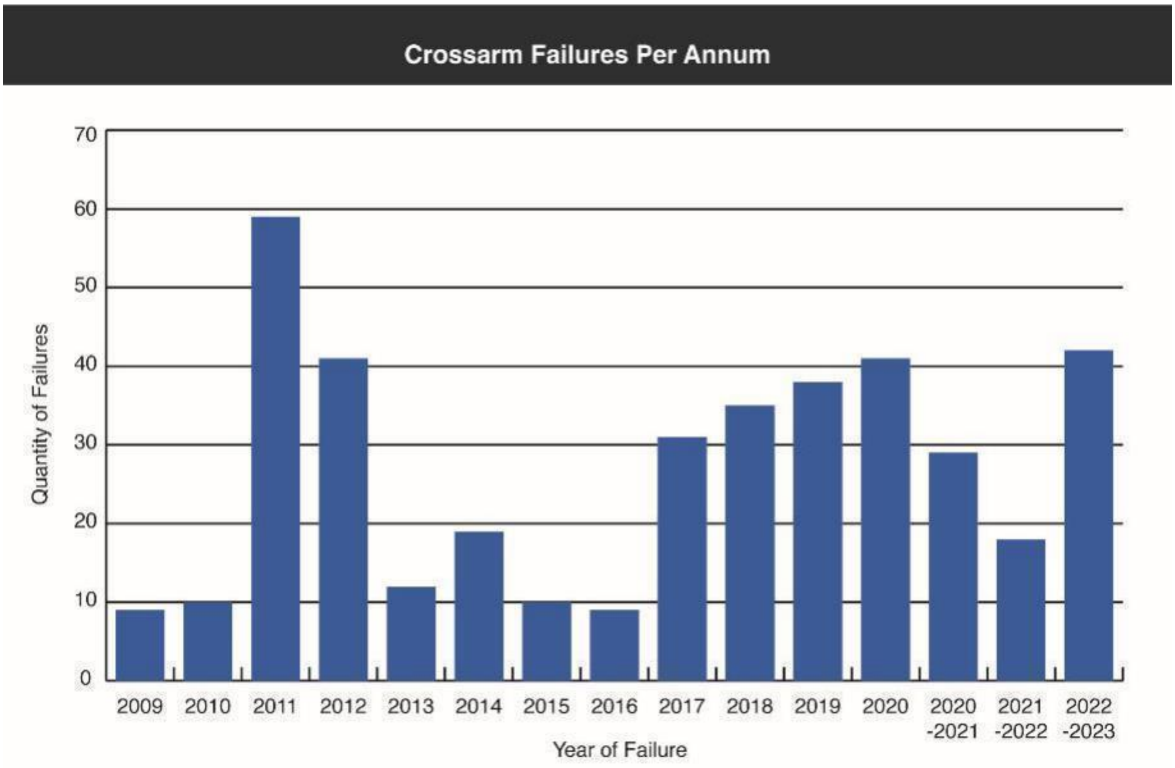
Crossarm Voltage	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2020 /21	2021 /22	2022 /23
LV	7	5	0	23	8	10	4	8	25	26	34	37	28	12	37
HV	2	6	46	18	5	9	6	1	6	9	2	4	1	6	5
ST	0	0	13	0	1	0	0	0	0	0	0	1	0	0	0
Totals	**9**	**11**	**59**	**41**	**14**	**19**	**10**	**9**	**31**	**35**	**36**	**42**	**29**	**18**	**42**

The age profile of the wood crossarm population indicates that there is a large percentage of LV wood crossarms that are operating beyond their expected asset life. Historically this has been reflected in the large number of in-service failures. Recent investment in reducing the backlog of maintenance notifications related to LV crossarms has resulted in a decrease in failure rates, however, the trend shows that in-service failures for LV crossarms have been significantly increasing. In order to maintain the current level of in-service failures continued investment in LV crossarm replacement will be required.

The number of in-service crossarm failures of ST and HV crossarms is on a downward trend assisted by the pole top fire mitigation program. This program targets at risk timber ST and HV crossarms and replaces them with new steel crossarms. This trend is expected to continue into the future as the population of timber ST and HV crossarms diminishes with time. It is anticipated that over the next decade all timber ST and HV crossarms will be all replaced with steel crossarms.

Maintenance plans and projects are reviewed regularly to ensure JEN assets perform satisfactorily, against regulatory obligations and customer expectations. A focus remains on the rectification of maintenance notifications in a timely manner so as to reduce this breakdown frequency.

Figure 4-18: Crossarm failures per annum (in-service and third party impact)



4.2.3.2.2 Corrective Maintenance Measures

The timely and satisfactory completion of identified maintenance tasks and activities are monitored via;

- The Bushfire Mitigation Index
- Close out of SAP Notifications

These are measures of the achievement of performance targets for critical activities in the Bushfire Mitigation and Inspection/Maintenance programs.

The performance of this analysis is underpinned by the following factors:

- There is a very high level of confidence in the accuracy and completeness of data (characteristic and condition);
- The Asset Inspectors apply the asset assessment criteria correctly every time; and
- Pole top failures are always reported accurately in JEN’s corporate systems (e.g., SAP)

The Pole Top sub-asset class has been categorised according to its operating voltages, namely ST, HV and LV.

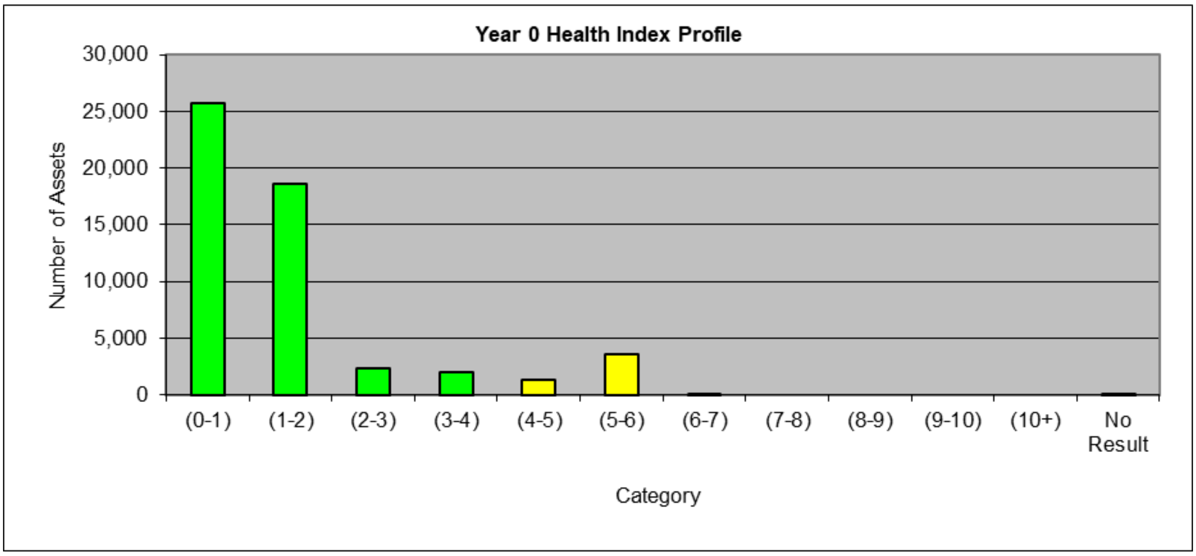
4.2.3.2.3 CBRM Condition Assessment

Outputs from the CBRM model are used to provide an assessment of crossarm condition. CBRM outputs in the form of Health Indices (shown in sections below) provide a visual demonstration of the condition of the population of pole top structures now and into the future.

4.2.3.2.3.1 ST and HV Crossarms Condition Assessment

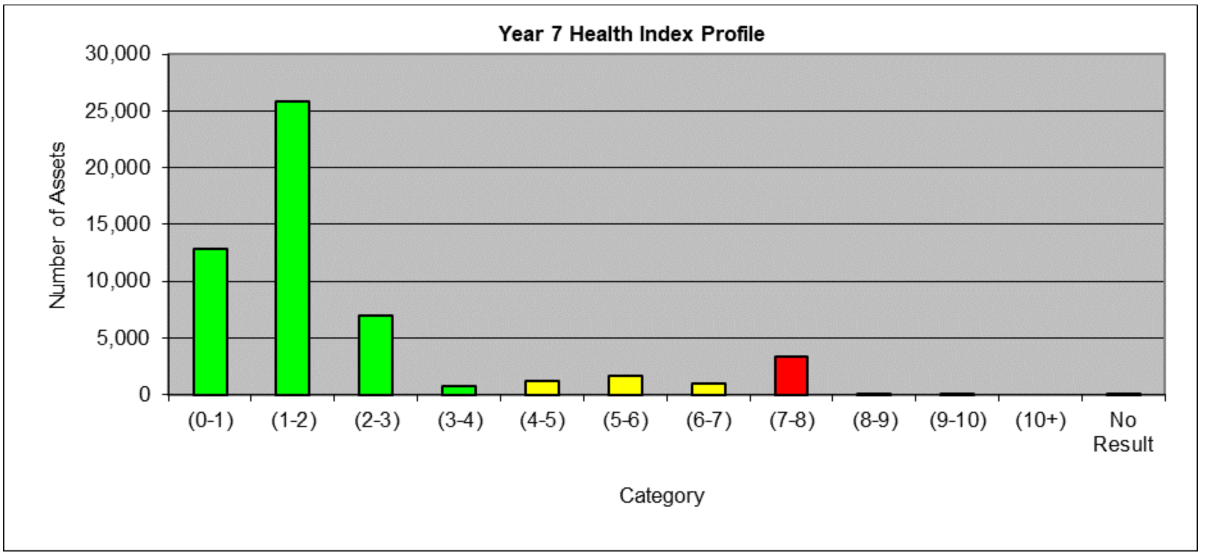
Figure 4-19 shows the current Year 0 (2024) health index for the population of ST and HV crossarms.

Figure 4-19: Year 0 (2024) Health Index Profile, ST and HV Crossarms



At Year 7 (2031), the health index is predicted to change as shown in Figure 4-20. A total of 3,385 crossarms will be in poor condition with an associated higher probability of failure (health index of 7 or greater).

Figure 4-20: Year 7 (2031) Health Index Profile, ST and HV Crossarms

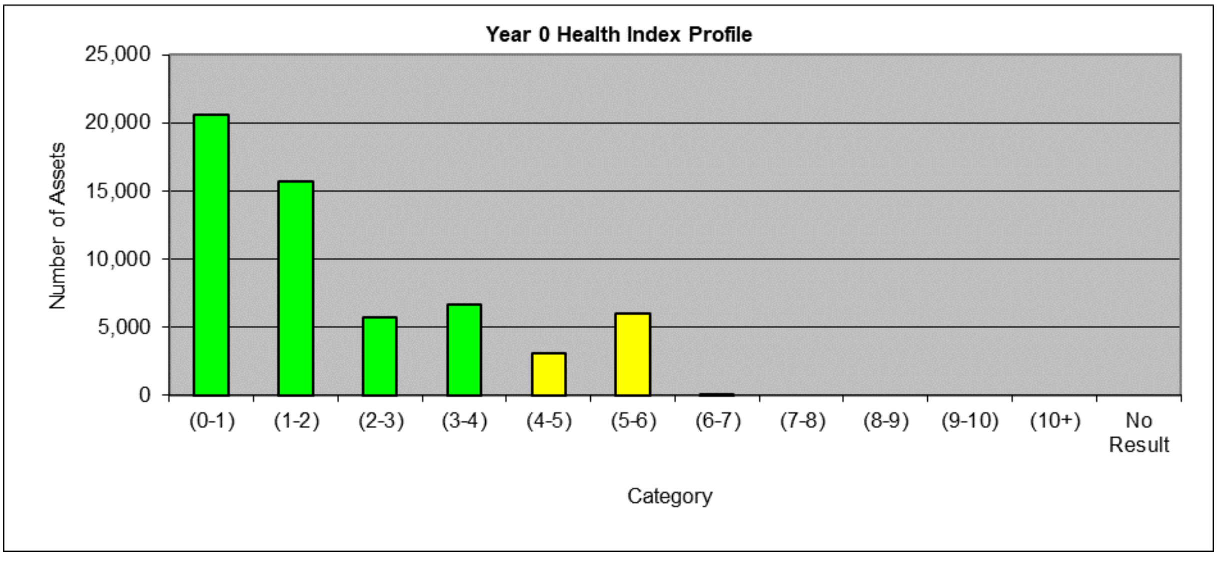


These results indicate that the majority of the population of ST and HV crossarms are in good condition. This is consistent with the fact that approximately 88% of the ST and HV crossarm population are steel crossarms and are well below their expected 70 year life. However, the remaining 12% of this population are timber crossarms and of these approximately 50% are at or have exceeded their 45 year life expectancy. These timber crossarms are the cause of the forecast numbers of crossarms that have a health index of 7 or greater in 2031.

4.2.3.2.3.2 ST and HV Insulators Condition Assessment

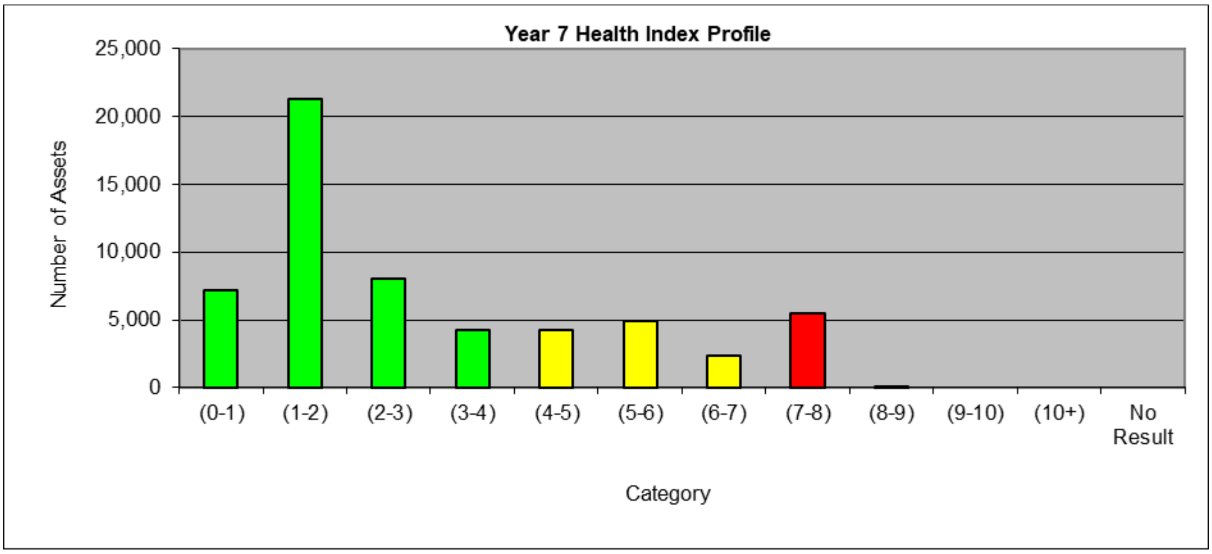
Figure 4-21 shows the current Year 0 (2024) health index for the population of ST and HV insulators.

Figure 4-21 Year 0 (2024) Health Index Profile, ST and HV Insulators



At Year 7 (2031), the health index is predicted to change as shown in Figure 4-22. A total of 5,527 insulators will be in poor condition with an associated higher probability of failure (health index of 7 or greater).

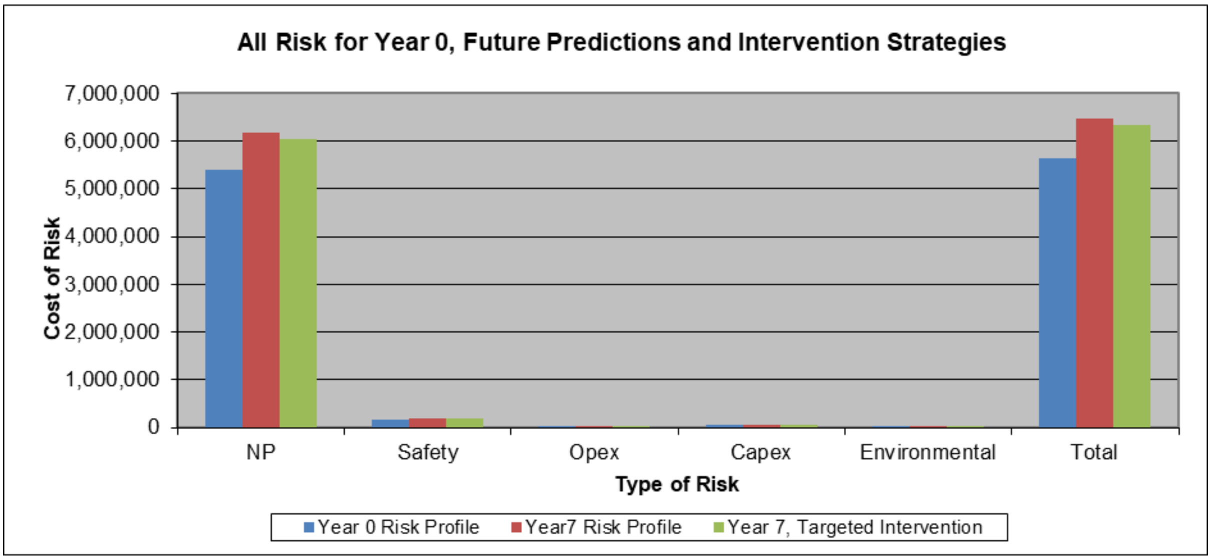
Figure 4-22: Year 7 (2031) Health Index Profile, ST and HV Insulators



The forecast health index profile at year 7 for ST and HV insulators is consistent with the number of wooden ST and HV crossarms remaining on the network and the insulators that will be associated with these assemblies. These insulators can be expected to be at or in excess of their expected life of 45 years.

The assessment of network risk for both ST and HV crossarms and insulators is combined within the CBRM model and based on a crossarm and insulator assembly. The risk to the network should an assembly fail is highly influenced by the risk to network reliability as indicated in Figure 4-23.

Figure 4-23: Risk Profile for Year 0 (2024) and Year 7 (2031), ST and HV crossarms and insulators



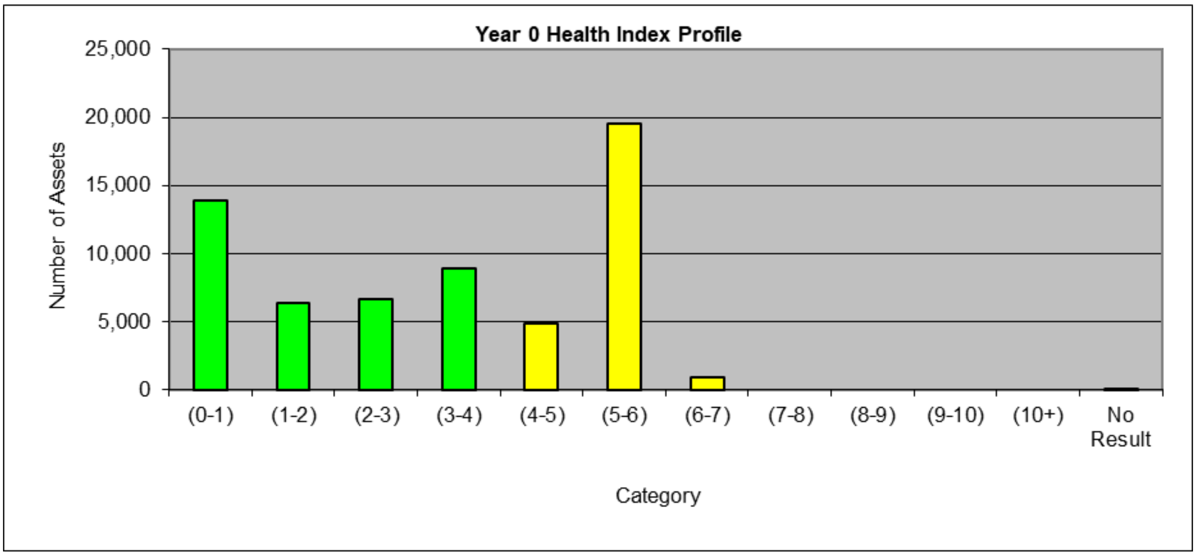
The CBRM model forecasts a total of 430 ST and HV crossarms and associated insulators need to be replaced per annum over 7 years to maintain the network risk of ST and HV crossarm and insulator assembly failures at current levels.

In order to maintain the assessed risk associated with the operation of these assets at current (year 0) levels this strategy proposes the replacement of approximately 430 crossarms and insulators per annum over the course of the next 7 year period driven by asset condition assessments. At the end of this period this strategy will result in the near elimination of the remaining ageing population of ST and HV timber crossarms.

4.2.3.2.3.3 LV Crossarms Condition Assessment

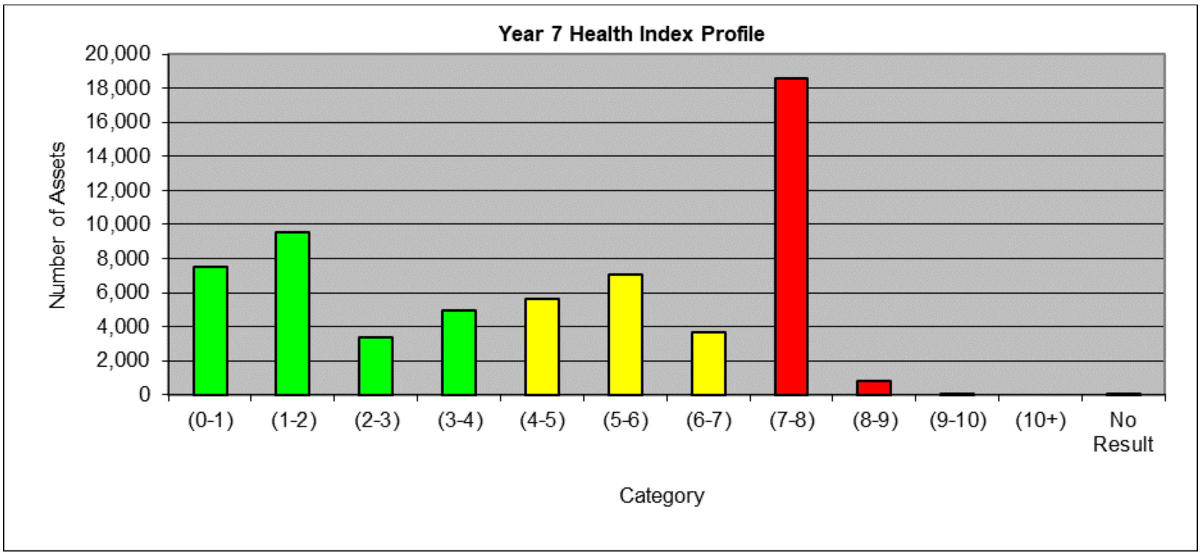
Figure 4-24 shows the current Year 0 (2024) health index for the population of LV crossarms.

Figure 4-24: Year 0 (2024) Health Index Profile, LV Crossarms



At Year 7 (2031), if no intervention occurs then the health index changes as shown in Figure 4-25. A total of 19,413 crossarms will be in poor condition with an associated higher probability of failure (health index of 7 or greater).

Figure 4-25: Year 7 (2031) Health Index Profile, LV Crossarms

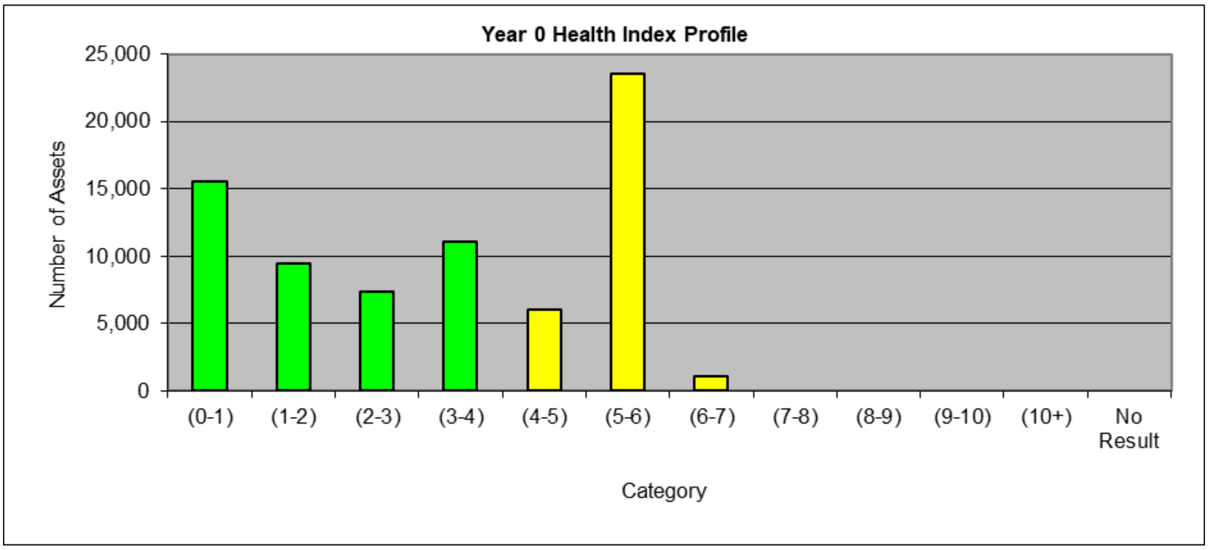


These results indicate that a significant proportion (greater than one quarter) of the population of LV crossarms are approaching their expected asset life of 45 years for wooden crossarms.

4.2.3.2.4 LV Insulators Condition Assessment

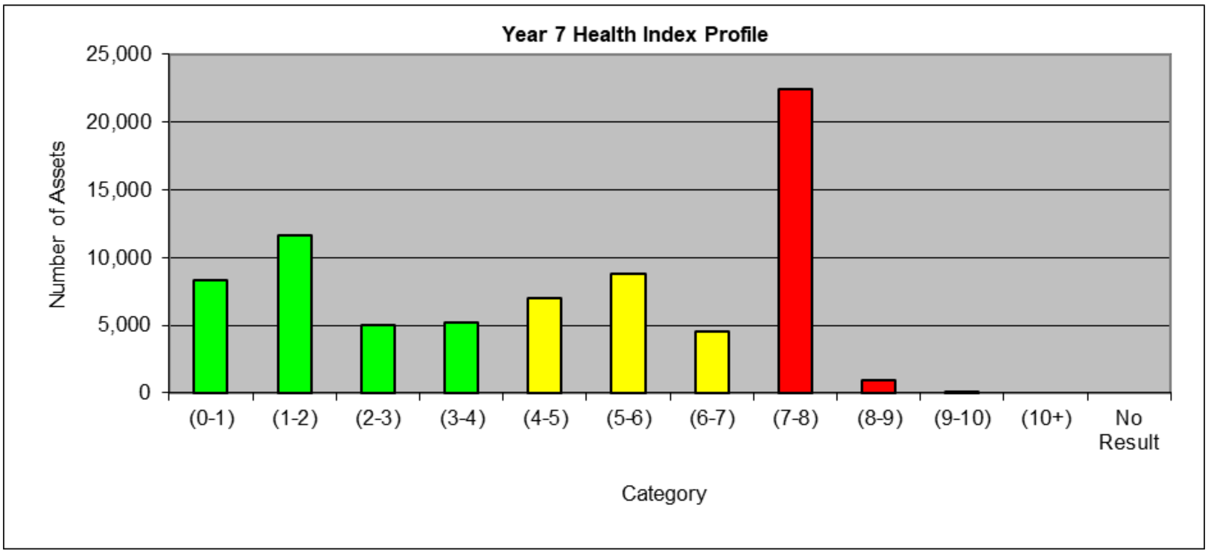
Figure 4-26 shows the current Year 0 (2024) health index for the population of LV insulators.

Figure 4-26: Year 0 (2024) Health Index Profile, LV Insulators



At Year 7, the health index changes as shown in Figure 4-27. A total of 23,461 insulators will be in poor condition with an associated higher probability of failure (health index of 7 or greater).

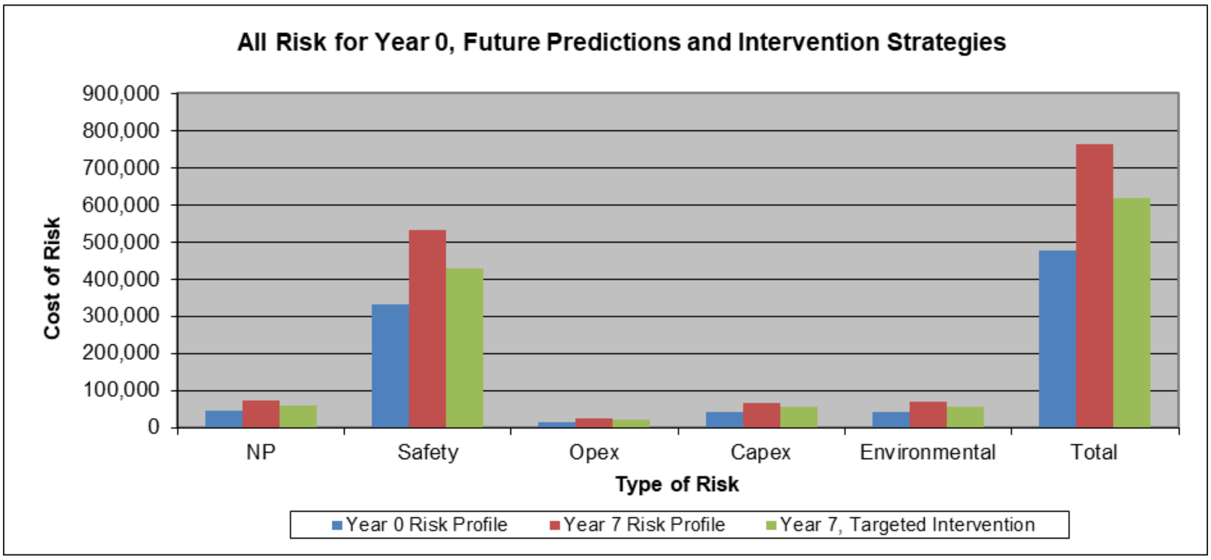
Figure 4-27: Year 7 (2031) Health Index Profile, LV Insulators



These results indicate that significant proportion of the population of LV insulators are approaching their expected life of 45 years.

The CBRM model treats the LV crossarms and LV insulators as an assembly and assesses risk on this basis. The risk to the network should an assembly fail is highly influenced by the risk to safety as indicated in Figure 4-28: Risk Profile for Year 0 (2024) & Year 7 (2031), LV crossarms and insulators.

Figure 4-28: Risk Profile for Year 0 (2024) & Year 7 (2031), LV crossarms and insulators



In order to maintain the network risk at approximately current levels the CBRM model forecasts the need to replace 3,260 LV timber crossarms and insulator assemblies per annum over the next seven years. This is a significant increase on historical levels of LV crossarm replacement but consistent with recent replacements (6,600 LV crossarms replaced over the last three years, 2020/21/22).

The CBRM model forecasts are driven by the age profile and assessed health index of the LV crossarm population. Actual asset replacements however are driven by the results of asset inspections. In order to maintain the assessed risk associated with the operation of these assets at current (year 0) levels this strategy proposes the replacement of approximately 2,000 crossarms and insulators per annum over the course of the review period driven by the results of condition monitoring assessments. We consider this to be a prudent and efficient approach. It also help address our customers' expectations on maintaining network reliability and affordability.

4.2.4 RISK

The major risks associated with pole top structures relate to public safety associated with pole top fires and in service failures.

4.2.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. An asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is also used to rank importance of dissimilar sub-asset classes (e.g., transformers and surge diverters) to identify areas where risk should be managed first, and control measures implemented.

The pole top structures sub-asset class has an assessed asset criticality score of AC1 (Low) due to the consequence of pole top failure in terms of operational and health and safety impacts. These are considered minor impacts on customers.

4.2.4.2 *Failure modes*

The main failure modes for these assets include:

- **Wooden crossarm age related failure** – occurrence of timber rot (e.g., due to fungal fruit body) or termites reducing the quantity of sound wood until eventually the cross arm breaks, failing to support the insulators and conductors or other cross arm mounted assets;
- **Crossarm fire** – generally caused by excessive electrical tracking across the insulator surface and into structural timber elements. Often this can be attributed to a point contact between the insulator fixing and the cross arm surface due to loose hardware;
- **Insulator failure** – either physical failure due to material defect or applied stress or electrical failure to insulate due to pollution or deterioration of the surface or puncture through the material;
- Breakage of the **mounting hardware** or steel crossarm due to severe corrosion of steel components;
- Breakage of crossarms, insulators and hardware due external influences such as vegetation impact, vehicle impact and extreme wind; and
- Insulator flashover due external influences such as vegetation contact, lightning, birds and other animals

We discuss in section 4.2.3.1 failure rates for pole top structures.

4.2.4.3 *Current Risks*

Risks associated with the management of pole top structures are documented in OMNIA and reviewed annually. The main risks for pole top structures are:

- **Pole top fires:** This involves the ignition of timber pole top assets (including crossarms) and are generally caused by a combination of environmental related deterioration, loose pole top hardware, un-bonded metallic components and increased leakage currents associated with pollutants and unfavourable weather conditions. The conditions conducive to the ignition of pole top fires typically involve the accumulation of pollutants on the insulator surfaces, often following long dry spells followed by small amounts of moisture from light rain or fog. This allows larger leakage currents to flow resulting in pole top fires;
- **Unassisted in-service age related crossarm failure:** This is the risk of a crossarm failure during asset operation caused by rot (e.g., due to fungal fruit body), rust (on steel crossarms), termites and/or incorrect design. Historically, broken crossarms occur largely as a result of deterioration due to rot which occasionally goes undetected from the ground during routine asset inspection;
- **Assisted in-service crossarm failure:** This is the risk of third-party vehicles or trees impacting on JEN crossarms resulting in asset failure; and
- **Pin Insulators:** This is the risk associated with particular line pin insulators which have been identified as prone to failure by cracking of the upper or lower porcelain components. Also, the insulator glazing (predominantly brown and grey porcelain type) is deteriorating. This is generally accepted as an age related deterioration. It results in a build-up of contaminants contributing to larger current leakage which may develop into pole top fires.

The main risks outlined above all have similar consequences in terms of supply availability and health and safety. Potential consequence of these events include:

- Loss of supply;
- The health and safety of staff, contractors or member(s) of the public;
- High Voltage Injection (HVI) due to pole top structure being unable to support the HV conductors which may result in claims for property damage; and
- Risk of a fire start which may result in financial impact to JEN under the regulatory F-factor scheme, or the possibility of a bushfire start.

4.2.4.4 *Existing Controls*

The principal control applied to the management of the risks associated with the operation of this sub-asset class is the asset inspection program. The likelihood of any of the failure events described above of occurring is almost certain. JEN has a history of pole top fire and assisted and unassisted in-service crossarm failures occurring on an annual basis. To mitigate the likelihood of these risks assets are regularly inspected and assessed so as to maintain a high degree of confidence in the integrity and safety of this sub-asset class. The JEN Asset Inspection Manual (AIM) sets out the criteria and requirements for the inspection, maintenance and replacement of this sub-asset class. This is the principal condition monitoring activity applied to these assets and drives the replacement of these assets base on their condition.

JEN's design and construction standards, procedures and management plans are also all key controls in reducing the likelihood of these events from occurring. JEN's internal technical standards and design and construction manuals ensure all assets on the JEN network are fit for purpose and have been constructed so as to address and mitigate known risk factors.

Incident investigations are conducted to determine the cause of an asset failure and to put in place the appropriate action to prevent a similar incident from occurring again.

JEN has an established pole top fire mitigation strategy to reduce pole fires. The Pole Top Fire Mitigation (PTFM) program replaces wooden crossarms with steel crossarms for poles and/or feeders that have been assessed as being more susceptible to a fire start. The PTFM program has been effective, as evidenced by the downward trend in pole and crossarm fires. Weather conditions have a large influence on the number of pole top fires and hence the trend of pole top fires can fluctuate.

JEN ensure all staff and contractors have up to date training records to ensure they are competent and aware of potential hazards in the field and are able to attend to these risks safely.

The JEN Bushfire Mitigation (BFM) plan is a key control for the mitigation of the risk of fire starts in the HBRA. The JEN BFM plan details the policies and procedures that are to be followed and the preventative and corrective maintenance programs required in order to achieve compliance with the Electricity Safety Act 1998, the Electricity Safety (Bushfire Mitigation) Regulations 2013 and the Electricity Safety (Electric Line Clearance) Regulations 2020. One of the aspects of this plan is the monitoring of BFM program of works to ensure all BFM activities are completed prior to the start of the fire season. Executing this program of works helps ensure the potential for a fire start on JEN is minimal.

4.2.4.5 *Future Risks*

Emerging risks for this asset class include:

- The large population of LV wood crossarms and insulators that are forecast to be replaced due to age related condition (CBRM assessments); and

- The management of the volume of maintenance notifications associated with this sub asset class.

JEN's technology strategy involves investigating new technologies to improve network safety and reduce costs. Future improvements being explored for this asset class involve the following:

- The elimination of pole top fires by the accelerated replacement of at risk pole top structures with current steel crossarm designs. This is occurring under the PTFM program, and there has been a downward trend in pole top fires;
- The continued monitoring of the performance of bird and animal protection systems. Investigate the possibility of a retirement program for poorly performing bird and animal covers based on the increase in reliability benefits;
- Consideration of the retrofitting of bird and animal protection on at risk structures in the HBRA. Structures including pole mounted substations, cable head poles, scout surge arresters, some switches or spur fuses. Consideration should also be given to concrete poles with steel crossarms or more complex pole top structures; and
- Consideration of the use composite insulated crossarms. There are 2 competing perspectives; continue to maintain open wire LV mains (crossarms required) or, when LV assets become unserviceable replace with LV Aerial Bundled Conductor (ABC). In practice, due to cost factors, it is likely both technologies need to be maintained.

4.2.5 LIFE CYCLE MANAGEMENT

Since the introduction of the GIS in 1995, SAP in 1998 and Field Data Capture (FDC) units also in 1998, line inspectors have assessed the condition of poles at the ground line and also noted any obvious signs of deterioration of pole top hardware. For many years, emphasis has been placed on investigating asset failures and sharing findings with asset inspectors and accordingly their skill level has increased. Asset Inspectors now monitor the condition of every asset attached to the pole. For the purpose of this sub-asset class, this includes crossarms, insulators, insulator ties, braces, bird covers and bolts.

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement of pole top hardware.

The strategy includes time based asset inspections followed by condition based maintenance and replacement, as well as in-service failure based corrective maintenance.

4.2.5.1 *Creation*

Three scenarios trigger the need to acquire and install new cross arms and insulator assemblies:

- Installation of new equipment;
- Replacement due to failure; and
- As part of routine maintenance or as a result of overhead line inspection programs.

All new pole tops structures are installed in accordance with the current JEN design, construction and material standards. The principal standards used for the creation of these assets are;

- Overhead Line Design Manual – ELE 999 OM DN 001; and
- Distribution Construction Manual – ELE 999 OM CN 001;

4.2.5.2 *Asset Operation and Maintenance*

There are three (3) life cycle management strategies applied to the operation and maintenance of the pole top sub-asset class:

- Condition Monitoring – Asset Inspection;
- Preventative Maintenance - (replacement due to condition); and
- Reactive and Corrective Maintenance

4.2.5.2.1 Condition Monitoring - Asset Inspection

Poles and pole tops are inspected as part of the asset inspection program on a four-yearly cycle in the LBRA and a three-year cycle in the HBRA.

Pole and pole top asset inspection is a condition monitoring procedure used to monitor the condition of pole tops and prioritise maintenance and replacement activities intended to maintain network performance at desired levels. The scope of this inspection plan includes wood poles (prevention of climbing animals), transformer bushings, crossarms, crossarm braces, bolts, insulators, conductor, bird and animal covers, fuse brackets, cable terminations and surge arrestors. Identified visible damage and deterioration are attended to on a priority basis. This system of inspection helps to maintain the reliability of HV and ST feeders.

The cycle for pole top inspection is the same as the pole asset inspection cycle and both assets are inspected at the same time. A visual inspection of the pole top is conducted during every inspection to identify detached or damaged pole top equipment (such as splits, cracks, and bends in the crossarm), fungal fruiting bodies, rot, or missing pole caps. LV ABC brackets are also visually inspected during pole top structure inspections and have a condition based replacement strategy. During the visual inspection of LV ABC brackets the brackets are assessed and checked to confirm if the galvanising has deteriorated on the bracket.

The asset inspection programs determine the preventive maintenance and planned replacement of pole top structures that could potentially fail causing line outages. For more information on the pole top structure asset inspection program refer to Section 8 – Line Hardware of the AIM.

The asset inspection strategy adopts different inspection programs and cycles dependent on whether pole lines are located in the HBRA or LBRA which are detailed below.

4.2.5.2.1.1 Inspection in the LBRA

In the LBRA pole top structures are inspected as part of the asset inspection program on a four-year cycle. In cases where the inspections identify a pole top structure that looks deteriorated, but it is difficult to accurately determine the extent of deterioration, an aerial inspection may be arranged. In these instances, an inspection from close-up and from above enables an accurate assessment of the asset condition. This type of assessment is organised at the discretion of the asset inspector.

4.2.5.2.1.2 Inspection in the HBRA

Similarly, in the HBRA asset inspection is carried out on the same basis but on a three-year cycle. In addition, a visual inspection is currently performed for all lines in the HBRA annually prior to summer. This annual inspection is intended to identify any obvious hardware defects which may result in a fire ignition or cause a supply outage. In addition to this, extensive auditing of lines in the HBRA occurs prior to and during the declared fire danger period.

4.2.5.2.1.3 Private Overhead Electric Line (POEL) Inspection

All POEL are inspected on a three-year cycle; in the HBRA the cycle coincides with the inspection of distribution assets and in the LBRA the cycles are autonomous and mutually exclusive.

For the detailed inspection criteria refer to the JEN Asset Inspection Manual.

4.2.5.2.2 Preventative Maintenance

Pole top structures are considered to be maintenance free. Although methods to treat/refurbish crossarms exist, they are all considered either uneconomical or ineffective. Pole top structures have an expected engineering life of 45 years for wood crossarms and 70 years for steel crossarms, provided they are installed correctly.

The environmental and atmospheric conditions prevailing across the JEN area do not justify insulator washing programs. In addition, these has been found to be ineffective in the prevention of pole top fire. Consequently, this activity is not performed on the JEN.

Refurbishment of pole top structures is not an efficient lifecycle management option for crossarms for two main reasons:

- There is no known technology available which can extend the life of already decayed timber; and
- The labour cost associated with an arm replacement far outweighs the material cost. Therefore, it is significantly more cost effective to allow a wood crossarm to reach the end of its economic life and then have it replaced with the current standard crossarm.

4.2.5.2.3 Reactive and Corrective Maintenance

Any pole top component found to be defective or significantly deteriorated during the asset inspection cycle shall be assigned a priority in accordance with the descriptions in the AIM. Defects are also identified following audits and occasionally work remains to be completed post temporary fault repairs.

Faults and defects that pose a risk to public health and safety will be corrected immediately; using live-line techniques wherever possible.

Pole or pole top fires in particular have a significant impact on the JEN network in terms of network performance and public safety. Pole fire events can be large scale events that occur in a short period of time and may stretch resources. The population of wooden HV crossarms is slowly diminishing due to the practice of replacing wooden HV crossarms with steel crossarms through the asset replacement process and the PTFM project. The age of the remaining wooden crossarm population is increasing. It is anticipated that the scale and frequency of future pole fire events will continue to decrease as the remaining HV wood crossarms are retired.

4.2.5.3 *Asset Replacement*

4.2.5.3.1 Replacement of crossarms

Crossarm replacement is the only practical (cost effective) option available for the management of crossarms which have reached the end of their economic life. The criteria employed to determine the end of economic life (asset condition) is optimal from the perspective of ensuring the crossarms are not replaced too early (excessive residual life) or too late (increased failure rate). There are established programs for replacing:

- Deteriorated HV wood crossarms with steel crossarms on HV distribution feeders and sub-transmission lines based on crossarm condition;
- Deteriorated LV wood crossarms based on asset condition; and

- HV and ST crossarms as part of the pole top fire mitigation program. Inspections of identified high risk areas, nominate replacement of all crossarms with brown pin, brown post or brown disc insulators. Replacement of crossarms with other types of insulators mounted on them will be prioritised based upon evidence of charring, arcing or unacceptable deterioration of condition (e.g., cracking, deglazing, corrosion and crossarm damage).

The asset inspection programs drive the crossarm replacement requirements, refer to section 8 – Line Hardware of the AIM for details of the criteria for asset replacement.

4.2.5.3.2 Replacement of insulators

4.2.5.3.2.1 Replacement of 66kV Brown & Grey Fog Pin Insulators

Insulator replacements occur as part of the crossarm replacement works. There is no current program for the targeting of these particular insulator types aside from the crossarm replacement program. If any 66kV brown or grey fog pin insulators are identified as defective during inspections or other work, they shall be scheduled for replacement with current standard insulators and a steel crossarm. Also, during conductor replacement or augmentation projects any 66kV brown or grey fog pin insulators shall be opportunistically replaced with current standard insulators and crossarms as part of the project.

4.2.5.3.2.2 Replacement of Superseded 5 Shed 22kV Post Insulators

There has been a history of faults caused by bird flash-over across the superseded 22kV 5 shed 565mm creepage post insulators, which were mounted vertically or horizontally on steel crossarms or wooden crossarms on concrete poles. These are suitable for use on wooden poles only.

When these insulators are identified during inspection, and are mounted on a concrete pole, they will be replaced with the “stretched” 9 shed version of the same creepage distance, but 485mm physical clearance.

4.2.5.3.3 Pole Top Replacement - Forecast Volumes

As detailed in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

Table 4-19: Pole Top Forecast Replacement Volumes

Unique ID	Service Code	Pole Top Structures	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A218	RXG	ST Insulators Replacement	5	7	10	10	10	10	10
A227	RXI	HV Insulators Replacement	19	21	49	49	49	49	49
A227	RXI	HV Insulators Change (single)	8	8	8	8	8	8	8
A221	RXH	HV Crossarm Replacement	365	378	410	410	410	410	410
A228	RXL	LV Crossarm and Insulator Replacement	939	994	1,426	2,000	2,000	2,000	2,000
A241	RXS	ST Crossarm Replacement	5	7	13	20	20	20	20
A110	PDS	Bird/Animal Proofing	17	19	18	18	18	18	18

4.2.5.4 *Asset Disposal*

Pole top structures are not normally repaired as a failure usually results from condition or external factors which have damaged the asset beyond repair and usually require the asset to be replaced.

Pole top structures such as crossarms, insulators, braces etc. do not contain hazardous materials and should be disposed of in accordance with JEM PO 1600 (Scrap Materials Policy).

4.2.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.2.5.6 *Spares*

As part of criticality assessment consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). It has been determined that adequate spares are maintained at Tullamarine depot and stock holdings are managed.

4.2.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determine the information required to manage and operate an Asset Class.

The information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

SAP is used to capture assessment records, defect Notifications, PM Orders, Labour and Material costs, maintenance plans etc. The list is extensive but can generally be categorised as condition information or lifecycle management information.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives (

Table 4-20).

Table 4-20: Pole Top Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-21 identifies the current and future information requirements to support the Asset Class critical decisions and their value to the Asset Class.

Table 4-21: Pole Top Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Pole Top Acquisition and Application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied pole top components and hardware and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing / historical) - Status (in service, isolated, out of commission) - Operating voltage - Pole number (A-number) - Asset Status (e.g., existing) - Rated Voltage (for insulators) - Type - Material - Length - Depth - Width - Date Installed - Date Removed • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• No of Insulators • No of Armour Rods • No of Sheds • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-22 provides the information initiatives required to provide the future information requirements identified in

Table **4-21**. Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-22: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improved Asset Attributes	Review current asset attribution fields to ensure attributes being collected are asset specific.	Medium	Appropriate and Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.3 CONDUCTORS AND CONNECTORS SUB-ASSET CLASS

4.3.1 INTRODUCTION

JEN owns and operates approximately 4,500 km of overhead conductor at various operating voltages. This represents approximately 66% of the distribution network by network length. In conjuction with this there are many thousands of connectors deployed across the network.

4.3.1.1 *Conductors*

The overhead conductor types in use across the JEN include:

- All Aluminium Conductor (AAC);
- Aluminium Conductor Galvanised Steel Reinforced (ACSR);
- Copper Conductors;
- Cadmium Copper Conductors;
- Galvanised Steel Conductors;
- Low Voltage Aerial Bundled Conductor (LV ABC); and
- High Voltage Aerial Bundled Conductor (HV ABC)

These conductors are deployed on the Sub-transmission Network, the High Voltage Distribution Network and the Low Voltage Distribution Network. AAC type conductor is the current standard for all overhead HV and ST urban applications. LV ABC is the current standard for all overhead LV applications and is used in both urban and rural areas.

Bare aluminium and copper overhead conductors have been used in urban areas for residential, commercial and industrial distribution. They have also been used for the construction of sub-transmission lines all over the network. The design and construction of sub-transmission lines generally involves the use of large capacity conductors and the use of longer spans. Consequently the mechanical loads and associated conductor stringing tensions are high and approach the structural limits for the supporting structures.

Steel conductor is used mainly in rural areas where long spans are necessary to cover larger distances with small electrical load densities. Steel conductor used in the rural areas is also strung at very high stringing tensions and therefore armour rods and vibration dampers must be installed to combat conductor damage due to wind induced conductor vibration. This means that again the supporting structures operate at loads approaching the design limits. Fault levels are also an issue wherever steel conductor is used and care needs to be taken to protect the steel conductor from fault levels that could result in damge to the conductor or conductor burn down due to the passage of fault current.

Historically a large range of conductor types and sizes have been used to construct the network. Consequently a large range of sleeves, wrap-ons, connectors and spare conductor needs to be kept to facilitate the maintenance and repair of these assets.

Table **4-23** below indicates the length of overhead conductors by voltage category on JEN.

Table 4-23: Conductor Length by Voltage

Conductor	LV	6.6kV	11kV	22kV Single Phase	22kV Three Phase	66kV
Length (km)	2,489.7	52.4	205.1	235.5	1,191.5	321.9

4.3.1.2 *Connectors*

Connectors are categorised as either full tension or non-tention types. There are hundreds of non-tension and full tension connectors on every feeder out of every zone substation. In addition there are many thousands on the associated low voltage networks.

The standard full tension connector for use with AAC conductor is the compression sleeve. The standard non-tension connector for use with AAC conductor is the fired wedge type (Ampact) connector. Historically many types of non-tension connectors have been used on the network including compression sleeves, parallel groove (PG) clamps, D clamps, U-Bolt connectors, split bolts and fired wedge (Ampact) connectors. These connectors are on every strain, tee off, cable head, anchor pole, etc.

Full tension connectors are not used with LV ABC, rather the cable is terminated at a pole and connected to the next span using non-tension insulation piercing connectors.

4.3.2 ASSET PROFILE

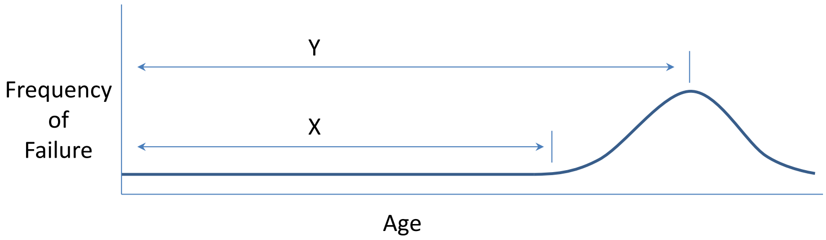
4.3.2.1 *Life Expectancy*

The life expectancy and information on the range of installation dates for the various conductor types used on JEN are indicated in Table 4-24. The oldest copper conductors in service date from the 1920's. The current standard Aluminium Alloy Conductor (AAC) was first introduced in 1975 and is the most widely used bare conductor in the urban areas.

Table 4-24: Conductor and Connector Life Expectancy and Installation Date

Conductor Type	Installation Years	Useful life 'Y' (Nominal Years)	Span Y-X (Nominal Years)
Copper	1920 – 1960	60	20
Cadmium Copper	1960 – 1975	60	20
Steel (Sc Gz)	1960 – 1975	50	20
ACSR	1960 – 1975	50	20
AAC	1975 – present	60	20
LV ABC	1990 – present	50	20
HV ABC	1994 – 2011	35	10

Figure 4-29: Graph of Conductor and Connector Wearout Characteristic



Conductor and connectors displays a wear-out characteristic of the type indicated in the figure above, with the onset of wear out at the end of the useful life. Asset failure follows a normal distribution at the end of the useful life period.

Despite the wearout characteristic above the life expectancy of connectors is a far more complex issue as it is very dependent on the following factors:

- Workmanship;
- Correct selection of size;
- Conductor type and size;
- Electrolitic corrosion associated with disimilar metals;
- Conductor preparation; and
- The magnitude and frequency of load cycles.

In addition the lack of data on connector types and their location on the network makes detailed analysis of there performance problematic.

4.3.2.2 *Age Profile*

The age profile for overhead conductor on the JEN is categorised by voltage in Figure 4-31 (LV), Figure 4-31 (HV) and Figure 4-32 (ST) below. Figure 4-31 indicates a step change in the rate of installation of LV overhead conductor that occurred around the time of the privatisation of the electricity industry. This coincided with a legislated change in construction methods requiring all new residential development to occur using underground services. This change is also reflected in the age profile data for underground cable which indicates a corresponding increase in the rate of installation of underground cable from 1990 onwards.

The rate of installation of overhead conductor in all voltage categories has remained approximately constant over the last two decades with the exception of HV single-phase overhead conductor. The installation rate of this conductor has increased in recent years due to the steel conductor assessment and replacement programs. These programs have resulted in the replacement of significant lengths of corroded steel conductor. In addition the removal of the Single Wire Earth Return (SWER) systems in the HBRA, to mitigate the fire start risk associated with these systems, has resulted in the growth in the installed length of HV single phase overhead conductor.

Figure 4-30 LV Conductors Age Profile

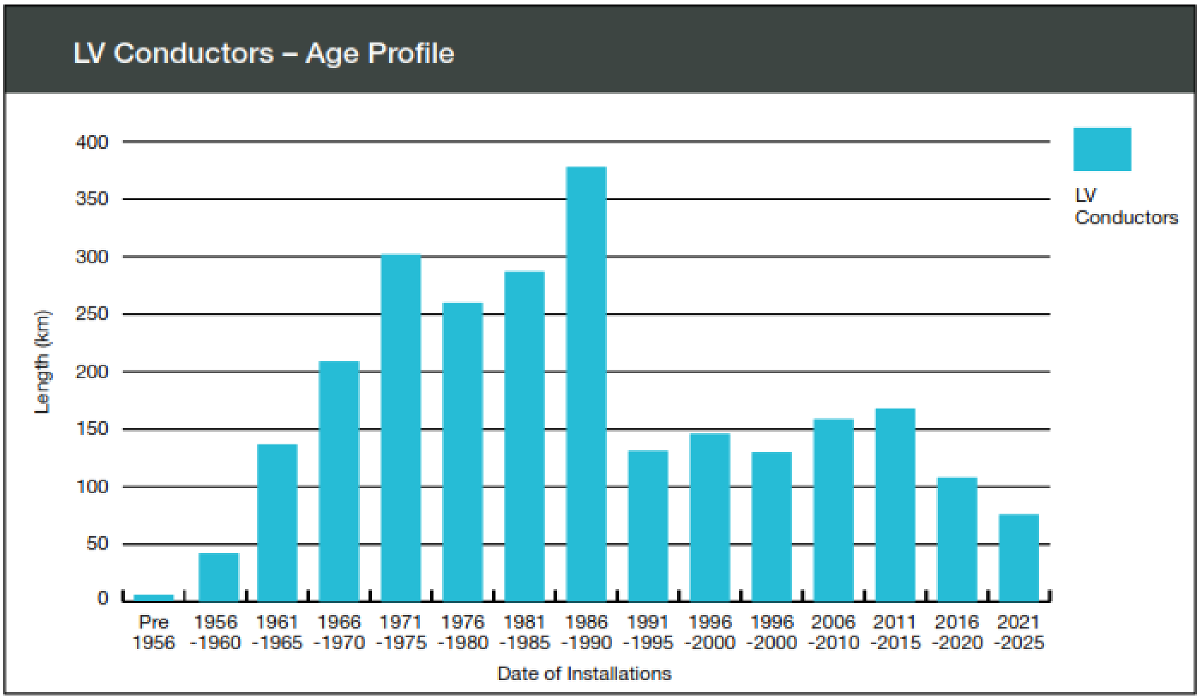


Figure 4-31 HV Conductors Age Profile

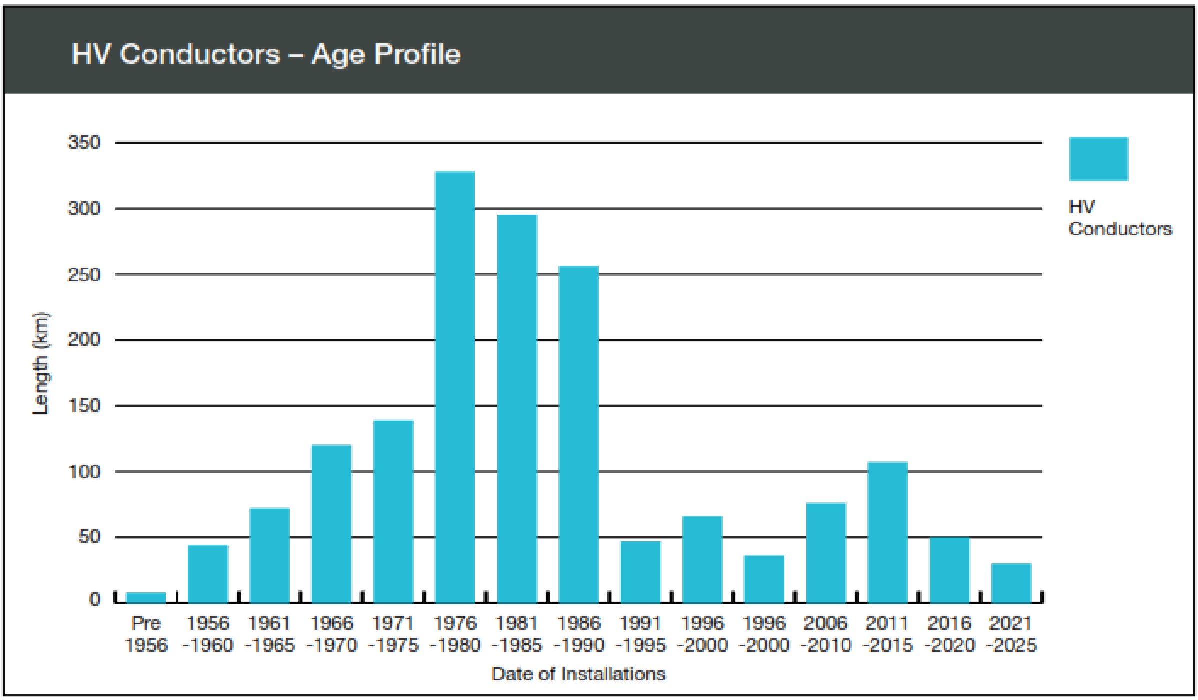
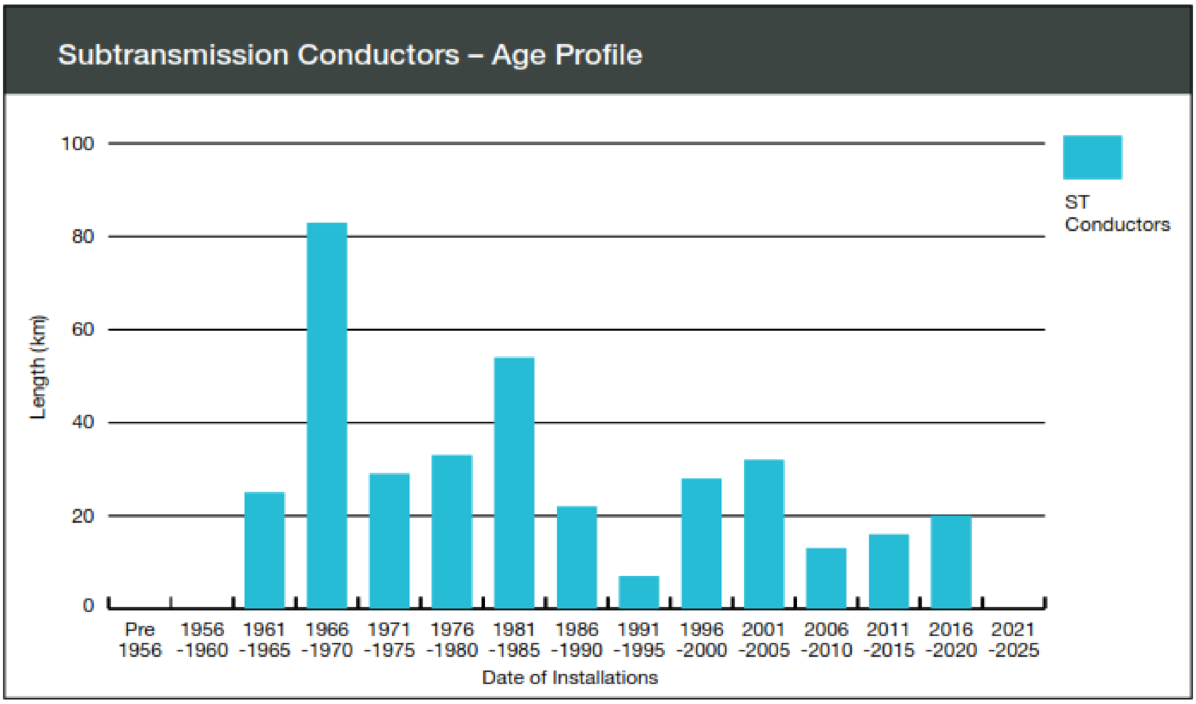


Figure 4-32 ST Conductors Age Profile



There is a small quantitiy (approximately 1.3km) of non-metalic screen HV ABC overhead conductor installed in the LBRA area of JEN. There is none of this cable type installed in the HBRA. This cable design has been found to suffer premature failure in service associated with the installation method. JEN has about 500m in service that is in excess of 20 years old.

4.3.2.3 *Utilisation*

4.3.2.3.1 Distribution Feeder Ratings

The capacity of a feeder is usually limited by the current carrying capacity of the overhead or underground sections on the main backbone. The limiting section of a backbone is likely to be close to the zone substation.

Generally feeders are loaded up to 70-85% utilisation as this is the point most augmentations become economic. This allows part of the load from a faulted feeder to be transferred to each adjacent feeder at peak load times.

In some areas this may not provide 100% backup due to insufficient ties and so emergency ratings may need to be utilised. It is a matter of probabilistic analysis as to the amount of risk this represents. Once the utilisation moves above 67% there will be in general a less than 100% backup capability.

4.3.2.3.2 Overhead Line Rating

The current construction standard for new overhead lines is for a maximum operating temperature of 65°C. Many older lines were built to 50°C (120°F) maximum.

Current ratings are based on a summer ambient temperature of 35°C and a winter ambient of 10°C and a wind speed of 0.6 m/s. As there are many days where the summer ambient is above 35°C, this rating basis is currently under review.

Feeders are also limited by the differential rating which is generally based on the worst case of the minimum clearance obtained when a loaded feeder is above a subsidiary circuit at minimum temperature.

It is possible to operate AAC conductors at up to 80°C without long term anealing occurring providing that there is adequate ground and circuit to circuit clearance. Generally only new feeders are designed for the higher (80°C) maximum operating temperatures and in special situations.

Existing feeders can also be up-rated from 65°C to as high as 80°C. Up-rating can only be carried following a detailed survey of the conductor clearances. If the sections to be uprated are in urban areas where the span lengths are invariably short it has been found that very little construction work is required to achieve the up-rating. Up rating has implications for the performance af all the associated connectors.

There are no emergency ratings for overhead lines, however dynamic wind ratings may be available for certain weather conditions.

4.3.3 PERFORMANCE

4.3.3.1 *Requirements*

The requirements for overhead conductors and connectors are set out in JEN's technical specification "66kV, 22kV, 11kV and LV Overhead Conductors and Underground Cables" which references a number of relevant Australian Standards (see Table 4-25). In order to ensure that overhead lines achieve their designed operational ratings and ensure network reliability is maintained overhead lines are installed in accordance with the requirements of the following JEN standards:

- Overhead Line Design Manual – ELE 999 OM DN 001 (previously JEN MA 0005); and
- Distribution Construction Manual – ELE 999 OM CN 001 (previously JEN MA 0006).

JEN's internal standards ensure compliance with a number of regulations that cover the installation of overhead conductor systems. These standards include design parameters which address areas including clearances, conductor stringing, conductor clashing, and the recording of asset data including asset location and type.

All overhead conductors are assigned ratings (including cyclic ratings) that are based on the type of conductor, ground clearances and circuit to circuit clearances. In addition, fault ratings for conductors are specified to ensure cables are matched to the networks fault levels.

The monitoring and optimisation of the performance of the overhead distribution systems occurs via the use of the following systems and programs:

- Feeder loads are monitored and managed via SCADA;
- The LV network loads are monitored via the business objects application using AMI data;
- Faults and failures are monitored via the OMS;
- Defects and failures are monitored via the Plant Maintenance notification systems (SAP);
- The in service operating temperatures of conductors and connectors are monitored via infra-red thermal surveys with the intention of finding and preventing defects from becoming faults; and
- Monthly asset performance review meetings review performance and faults.

Table 4-25: Conductor and Connectors - Relevant Australian Standards

Standard	Title
AS 1222	Steel Conductors and Stays - Bare Overhead Part 1 Galvanized (SC/GZ) Part 2 Aluminium Clad (SC/AC)
AS 1531	Conductors - Bare Overhead - Aluminium & Aluminum alloy
AS 1746	Conductors - Bare Overhead - Hard drawn copper
AS 3607	Conductors - Bare Overhead, Aluminium and Aluminium Alloy – Steel Reinforced
AS/NZS 7000	Overhead Line Design

4.3.3.1.1 Current JEN Standards for Overhead conductors

The following standard overhead conductors are used for 11kV and 22kV distribution feeders:

- 19/3.25 AAC[1] (Standard); and
- 19/3.75 AAC (High capacity)

19/3.25 AAC is the preferred choice for all new overhead construction.

In the former Municipal Electricity Undertaking (MEU**)** area of Footscray 19/3.75 AAC was used to match the capacity of the original 0.2 square inch Copper conductor feeders.

19/3.75 AAC is used in heavy industrial areas, where high capacity interconnections are required or in stations where additional feeder exits are not available.

6/1/3 ACSR is used at rural locations where load densities and lower fault levels exist, for example spurs that are not likely to become a tie line or part of the backbone feeder or have a substantial load increase in the foreseeable future. Voltage drop and network losses need to be considered where this conductor is used.

The standard overhead LV mains conductor is 150mm^2 LV ABC.

4.3.3.2 *Assessment*

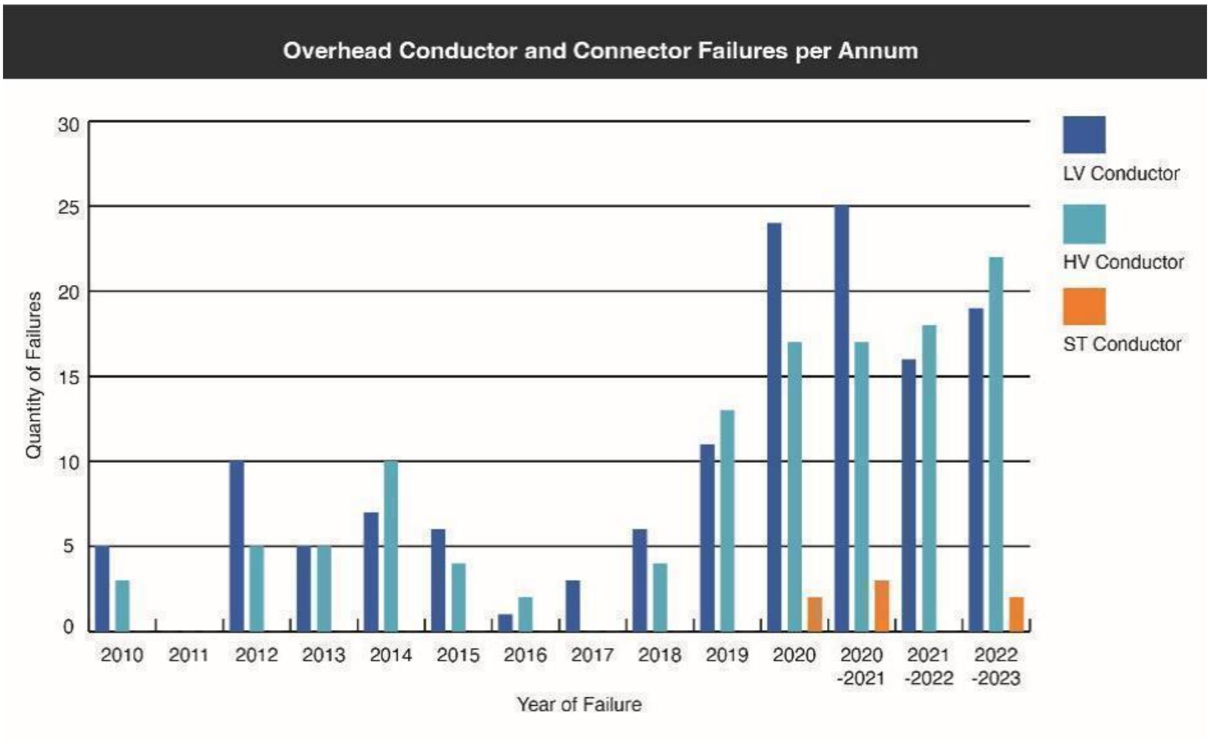
Specific conductor and connector performance measures (and condition monitoring) include the following:

- Reporting tree related faults;
- Fire starts; and
- Maintenance notifications resulting from the infra-red thermal surveys.

Each of these measures is reported on a monthly basis at an aggregate level, to which performance of conductor and connectors contribute. Figure 4-33 below shows an increasing trend in conductor failures.

[1] 19/3.25 AAC is the naming convention used to describe conductor size and type. That is 19 strands of 3.25mm diameter aluminium alloy conductor. Approximately a 150mm^2 cross sectional area.

Figure 4-33 Conductor and Connector Failures



4.3.4 RISK

4.3.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is used to rank importance of dissimilar sub-asset classes (e.g., transformers compared with buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

The conductor and connectors sub-asset class has an asset criticality score of AC4 (High) due to the health and safety consequences (for example, accidental connection to the switch wire or fire starts associated with conductor or connector failure).

Recognising this JEN has implemented several programs to minimise the likelihood of connector or conductor failure. The programs include:

- Steel Conductor Assessment Program (SCAP) in the HBRA which prioritises the replacement of steel conductor based on the assessed condition. This program is in addition to the routine asset inspection program;
- Installation of vibration dampers and armour rods where required. This program is complete for all conductor type/materials in the HBRA. An equivalent program in the LBRA was completed completed in 2020 in line with regulatory requirements;
- Replacement of unreliable non-tension connectors in the HBRA (e.g., parallel groove clamps, wire wound D-loops);
- Installation of LV spreaders where required;

- Removal of open wire LV mains in the HBRA;
- Routine asset inspection at a 3-year cycle in the HBRA and 4-year cycle in the LBRA;
- Electric Line Clearance Management Program;
- Hazard Tree Management Program;
- Auto Reclose suppression for feeders on Total Fire Ban (TFB) days; and
- Facade Mount Rectification Program

Through ESV audit and routine inspection, a number of sites have been identified with façade-mounted assets that pose a safety risk and remedial action is required.

At these locations, low voltage supply cable is positioned atop a shop's façade. This presents a hazard for individuals requiring access to this area. Some sites have had temporary remediation solutions implemented, given that exposed wiring and low voltage Aerial Bundled Cable (ABC) are in proximity to metallic surfaces on shop verandas.

We have an obligation to plan and develop our network to comply with network performance obligations and minimise the risk associated with asset failure.

4.3.4.2 *Failure Modes*

Failure modes for conductor and connectors include:

- Corrosion of conductor material resulting in reduced cross sectional area, reduced tensile strenth, conductor annealing and ultimately fusing and physical breakage, this is particularly an issue for steel conductor, ACSR and small cross-section AAC;
- Conductor breakage due to work hardening embrittlement caused by wind induced aeolian vibration This leads to fatigue failure of the conductor;
- Conductor overload resulting in elevated operating temperatures which leads to conductor annealing, loss of tensile strength, increased conductor sag and reduced conductor clearances;
- Corrosion of connector/conductor interface causing high resistance joint, and fusing particularly when conducting fault currents;
- Loss of clamping tension due to load cycling of connector resulting in breakage or fusing of the joint;
- Conductor breakage due to external influence such as vehicle impact to poles or trees falling onto lines; and
- For non metalic screened HV ABC, insulation deterioration which progresses to flashover between the live conductor and the earthed screen. This can cause molten particles to fall with a very high risk of fire starts.

The consequence of these types of failures of conductors and connectors can include equipment damage, supply outages and damage to customer's equipment from HV injections. However, the criticality assigned to this asset group results principally from the risks associated with three major failure consequences, namely:

- Supply interruption;
- Fire start including bushfire start; and
- Electric shock or electrocution associated with live conductors on the ground.

Of the above consequences, supply interruption is the most likely. Electric shock or electrocution is a rare consequence and fire starts most commonly occur in the LBRA and are generally restricted to a small portion of a nature strip.

Fire starts can also have a financial impact for JEN under the regulatory F-Factor scheme.

4.3.4.3 *Current Risks*

The major risks associated with conductor and connectors are related to the consequences of failure mentioned above. These risks are documented and responisbililties are assigned and tracked in OMNIA (JEN Compliance and Risk Systems) as outligned in the JEN Compliance Management System Manual (JEM RCM MA 0001).

In the VESI , a number of incidents have occurred while work crews have been performing “Live Line” glove and barrier work on 7/2.5 and 7/3.0 AAC conductor. In these cases the conductors involved had experienced excessive conductor damage at the point of contact with the insulator. This damage was not obvious to the lineworkers until the conductors were untied and lifted from the insulator. The cause of the conductor damage in these cases was aeolian vibration caused by the effect of steady winds on long spans of tightly strung conductor. This has led to live line work ceasing on these conductor types.

Similarly there are sections of 7/.064 copper conductor on the JEN network that cannot be worked on live due to the risk of conductor breakage. Consequently this has an impact on planned SAIDI.

The range of full tension type connectors used on the JEN include compression sleeves, helical splices, McIntyre sleeves and automatic line splices (Fargo sleeves). The use of Fargo sleeves on JEN has been banned due to a number of in-service failures associated with poor electrical connection at low stringing tensions and copper McIntyre sleeves have been phased out in favour of compression sleeves. The location and number of full tension connectors installed is not known and is very difficult to estimate. Although a program was undertaken to identify and remove Fargo sleeves from service proactively in the early 2000’s they continue to be identified from time to time by the asset inspection program.

The passage of fault current on HV feeders can result in secondary damage at connectors, in particular non-tension connectors such as PG clamps, Dee loops and U-bolt connectors. This occurs typically at bridges on strian structures, tee-offs or at switches and isolators. This type of secondary damage reduces system availability and the ability of the HV network to successfully restore supply in the event of transient faults. The reasons for this are:

- Damaged connectors can fail under load current at some time after the original fault;
- Single phasing of customer loads can result from failed connectors;
- Feeder patrol after a fault takes longer than necessary due to the need to inspect for obvious secondary damage. The requirement to patrol for secondary damage also reduces the potential effectiveness of automation and remote control systems; and
- Restoration of supply after a fault takes longer due to the need to repair secondary damage.

Patrol of feeders after faults can only identify visibly failed connectors, but not potential connector failures that could fail on re-energising or at a later time resulting in another outage.

The facade mounting of LV ABC cable was seen as a cost effective alternative to the undergrounding of LV overhead lines in high density strip shopping centers to improve streetscapes. A number of these projects were undertaken in places like Macaulay Road Kensington and High Street Preston. These installations however have proved to be problematic with the supporting building attachments failing and subject to damage due to interference. The location of the cables in relation to opening windows and over verrandas also allows potentially unsafe access to network assets by the general public.

4.3.4.4 *Existing Controls*

Table 4-26 below summarises some of the key controls currently applied to maintain an acceptable risk rating for the conductor and connectors sub-asset class. These risk controls result in a 'Moderate' risk rating for the sub-asset class compared with the untreated risk level which was assessed as a 'High'. The details of the current risk assessment is recorded in the relevant risk register in OMNIA.

Table 4-26: Existing Controls – Conductors and Connectors

Control Name
Design and Construction Manuals (provides a cohesive and consistent approach for the distribution network)
Thermal inspection program (1-3 year cycle) provides proactive alerts ahead of asset failure – Key control
Asset inspection manual (defines process and procedure for asset inspection) - Key control
Electric line clearance management plan (enables effective management of vegetation in vicinity of conductors) - Key Control
Steel Conductor Assessment Program (SCAP) which targets replacement in the HBRA – key control in the HBRA
HV spreader installation and removal policy (redesign structures to prevent clashing)

4.3.4.5 *Future Risks and Opportunities*

Conductor and connector risks are not expected to change in the near future. However, future improvements have been suggested to manage the current level of risk. Analysis of feeder faults involving secondary damage indicates that non-tension connector failure is a major cause. This has a significant impact on both SAIDI and SAIFI reliability indices.

The following are some options and strategies that JEN is considering to minimise future risks:

- Expanding the non-tension connector replacement program to feeder spurs not just the feeder backbone;
- Expanding the SCAP program in the HBRA to include conductor materials other than just steel conductors (e.g., copper, aluminium). Lines built with these other materials are of similar age to the steel conductor;
- Exploring other non-tension connector technologies (other than Ampact) to improve work practices; and
- Introducing modern HV ABC technology. Other DNSP's have experienced significant failures on non-metalic screened HV ABC conductor systems including fire ignitions. JEN has a small quantity of this cable type (1.3 km) located in the LBRA. The consequences of failure of these assets is deemed low given all of the HV ABC population is located in the LBRA area. Therefore, proactive replacement of these is not recommended at this stage.

4.3.5 LIFECYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement of conductor and connector hardware.

This strategy is based on asset inspections and condition assessment followed by condition based maintenance and replacement, as well as in-service failure based corrective maintenance.

The effective management of these assets will reduce the number of faults caused by connectors burning out, and reduce the incidence of secondary damage.

4.3.5.1 *Creation*

The need to acquire and connect new conductor and connectors is driven by:

- Installation of new overhead lines (may or may not include upgrade of existing lines) to facilitate the connection of new load and accommodate organic load growth;
- Replacement due to asset failure; and
- Condition based replacement.

The various types of conductor and connectors are typically purchased using period contracts in accordance with the requirements of the Distribution Construction Manual (ELE 999 OM CN 001) and the applicable material specifications.

4.3.5.2 *Asset Operation and Maintenance*

There are three (3) life cycle management strategies applied to the operation and maintenance of the conductor and connector sub-asset class:

- Asset Inspection and Condition Monitoring;
- Preventative Maintenance; and
- Reactive and Corrective Maintenance.

4.3.5.2.1 Asset Inspection and Condition Monitoring

Inspection of conductor and connectors is conducted as part of the overhead line inspection program, in accordance with the requirements of the Asset Inspection Manual (JEN MA 0500). The Asset Inspection Manual details the processes and procedures for JEN asset inspection and is the basis for routine inspections, observations and assessments. These criteria are applied by asset inspectors in order to maintain the integrity of the conductor and connectors sub-asset class.

Maintenance notifications are raised for the rectification of defects or replacement of assets as identified by the asset inspectors.

Thermal surveys have been altered and are now conducted on variable cycle which consists of an annual, two-year and three-year cycle. HV feeders are allocated to each group on the basis of risk ranking. High risk feeders, which are surveyed annually, are all business (e.g., industrial, commercial, hospital), highly loaded feeders (> 80%) or feeders with greater than 2,500 customers. Feeders with an average fault history of greater than 3 faults per annum will be surveyed on a 2-year cycle. All other low risk feeders are to be surveyed on a 3-year cycle. If a feeder is deemed a “rogue” feeder, then an additional survey may be ordered. All sub transmission lines are to be thermal surveyed on a 2 year cycle.

This enables, any faults detected by asset inspections and thermal surveys to be recorded and packaged into logical groups for maintenance rectification in the same electrical area. A complete list of all the feeders and the cycles can be found in SAP Maintenance Plans.

Steel conductor in the HBRA is visually assessed as part of the line inspection program to determine the extent of any conductor corrosion. High quality aerial photographic techniques are utilised to provide accuracy, consistency and confidence in the assessment.

When the Steel Conductor is assessed, the conductor is assigned a condition category from 1 to 10; where 10 is new conductor and 1 is severely rusted conductor. Steel conductor assessed with condition categories between 1 and 5 inclusive will be programmed for replacement.

4.3.5.2.2 Preventative Maintenance

The following are the key preventive strategies and requirements for the management of the conductor and connector sub-asset class on the JEN:

- The minimisation of end-of-life failures (typically due to corrosion) by specifying observable condition criteria, currently available for steel. Criteria are currently being developed for copper and aluminium conductor;
- The minimisation of the number of trees contacting overhead conductor. The single biggest cohort responsible for conductor breakage is trees. JEN has implemented vegetation management programs to minimise the occurrence of these faults and is now supplementing the HBRA programs with a continuing hazard tree management program;
- To maximise asset life and performance JEN have standardised on the use of All Aluminium Conductor (AAC) and Ampact connectors. In addition to cost savings through economies of scale these standards are proving beneficial in other ways. These include; minimised the variety and number of tools required; minimised the variety of spares held in stock; simplified work method statements and thereby improved safety of line workers; there have been no recorded cases of corroded aluminium conductor on JEN;
- It is more cost effective to use steel conductor in the HBRA due to the length of spans which can be achieved. In the absence of empirical data, it is assumed vibration dampers will extend the life of conductor by reducing micro abrasion caused by aeolian vibration. It must be noted that the installation of vibration dampers and armour rods in accordance with the standard is a regulatory obligation;
- All HV and sub-transmission non-tension connections shall be made with Ampact fired wedge connectors only (according to the JEN standard there are some exceptions for steel and copper conductor). On the LV network Ampact fired wedge connectors shall also be used.
- When a copper conductor needs to be joined to an aluminium conductor use an Ampact fired wedge and ensure the aluminium conductor is above the copper conductor to prevent corrosion;
- When maintenance or refurbishment works on HV line switches is undertaken connections shall be changed to Ampact stalk lugs;
- Copper to aluminium D loops with Live Line Clamps (LLC) are to be replaced with Ampact tin plated copper LLC bails. Copper to aluminium D loops with split bolt connections are to be removed and replaced with Ampact stainlees steel LLC bails;
- Aluminium alloy LLC's are to be replaced with brass LLC;
- Aluminium split bolt clamps are not to be used and shall be removed;
- Dampers and armour rods are to be installed at spans in accordance with the Line Construction Manual and at sites that have shown signs of Aeolian vibration damage. All steel conductor spans on intermediate poles in the HBRA will have armour rods and vibration dampers installed;
- All Fargo automatic line splices shall be removed and replaced with current standard full tension sleeves;
- All conductors shall be properly prepared i.e., brushed and cleaned before making connections;

- Aluminium conductors are to be located above copper conductors to mitigate corrosion;
- On bridges remove non tension sleeves and replace with a continuous bridging conductor connected with Ampacts at each end. Non tension sleeves in air break switch tails can remain in service if each end of tail has already been Ampacted and there is no defect on the non-tension sleeve;
- Bridges shall contain no more than two connections and shall be made with a conductor of equivalent rating or greater than the line conductor;
- New LV isolators shall be fitted with stalk lugs and old isolators changed to current standard;
- If double Ampacting is required, Ampact wedges must be installed 200 mm apart and both wedges must be fired in the same direction to prevent caging the conductor;
- Whenever a connector is being replaced on a pole, all HV connectors on each phase on that pole are to be replaced;
- There is no requirement to retain bolted non-tension connectors. Once such a connector is taken off the line it is not to be used again;
- All open wire LV spans in the HBRA will be fitted with spreaders (maximum 75m spacing between spreaders or spreader and crossarm as specified in the Asset Inspection Manual);
- All HV steel conductor on intermediate crossarms in the HBRA will be retrofitted with armour rods and vibration dampers; and
- All other conductor construction types (e.g., AAC, ACSR, Cu etc.) on intermediate crossarms in the HBRA will be retrofitted with armour rods and vibration dampers in accordance with the requirements of JEN standards.

4.3.5.2.3 Reactive and Corrective Maintenance

All reactive and corrective maintenance tasks result in the raising of a maintenance notification in SAP. Faults and defects are reported and rectified in accordance with directions given by the Control and Dispatch Centre or the priority assigned by the asset inspector.

4.3.5.3 *Asset Replacement*

The majority of all bare overhead conductors on the JEN are in good condition. The replacement strategies detailed below are specifically focused on stabilising and maintaining asset performance through replacement of conductor and connectors with identified poor performance issues.

The following replacement strategies are being applied to the conductor and connector sub-asset class on the JEN:

- The bulk replacement of connectors, such as PG clamps, U-bolts and Cu to Al Tee clamps, (Dee loops) on the HV system with Ampact fired wedge connectors shall be undertaken where fault mapping and cost benefit analysis shows this to be economically viable. This program proactively replaces non-tension connectors in the backbone of HV feeders and at the start of feeders based on fault history and I^2t or fault level considerations;
- The replacement of corroded copper and steel, and aluminium steel re-enforced conductors will be based on condition inspections and conductor failure history;
- The future replacement non-metalic screened HV ABC is likely to be required based on evidence from other DB’s and at least one failure within JEN. The failure rate and condition of this type of cable is being monitored, with failures anticipated to start occuring from 25 years of age. Replacements are to be assessed on case-by case basis, with options being, underground cable section, return to standard bare overhead where possible or installation of new fully sreened and earthed HV ABC;

- The proactive retirement of public lighting switch wire. This is a program that involves public lighting switch wires which have been largely redundant since the mid 1980's as lighting control was transferred to photo electric switching on each lantern. On the JEN the switch wires were not removed when old style luminaires were replaced with PE cell controlled luminaires and in many areas have remained in place for over 30 years as an unmaintained asset. A program to remove switch wire is being undertaken and JEN is on track to complete this program in 2024. The objective of this program is to remove the remaining public lighting switch wire to reduce operating risks and hazards and eliminate the risk associated with the ongoing degradation of unmaintained assets;
- There remains approximately 17kms of LV open wire mains in the HBRA of the JEN. The removal of LV Mains in the HBRA is a cost effective way of reducing JEN's bushfire risk. JEN is working toward the removal of all open wire LV mains in the HBRA. The program of works is planned for completion in early 2025. The LV open wire mains in the HBRA are being replaced using one or more of the following options:
    - Installation of a small (10kVA) pole mounted transformer and associated customer services;
    - Replacement of the bare LV mains with LV ABC (fringe areas of HBRA/LBRA only or where there are a minimal number of bays required rather than install a small kVA transformer), utilising existing poles; and
    - Undergrounding of the LV open wire mains and services on a case by case basis.
- It should be noted that all Single Wire Earth Return (SWER) systems in the HBRA of JEN were removed and replaced with three phase and single phase distribution feeders lines by 2013.
- Under our Façade Rectification Program, façade mounted LV ABC is being removed and made safe as required following inspection and condition assesment in a number of areas. The cable is being replaced with a combination of pole mounted assets and underground installations.
- Undersized neutrals. Neutrals represent an electrical reference point for several fundamental network components, including, transformers, conductors and connectors. An appropriately rated neutral is required to maintain both the electrical and safety performance of Jemena's distribution network.
- Customarily neutrals were designed for typical 3 phase balanced loads. However, with the evolution of electronically switched power supplies and exported energy, neutral currents have appreciably increased resulting in some overloaded neutrals. Undersized neutrals can cause poor supply quality, unsafe stray neutral/earth currents, and ultimately significant electrical and safety events upon failure.
- When an undersized neutral is identified it shall be referred to the Network Assets team for assessment.

4.3.5.3.1 Conductor and Connector - Forecast Replacement Volumes

As detailed in this strategy, a number of projects have been identified to ensure the maintenance of network performance, and also address our compliance requirements.

Table 4-27: Conductor and Connector Forecast Replacement Volumes

Unique ID	Service Code	Conductors and Connectors	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A444	PDA	Ampact Connectors	38	42	40	40	40	40	40
A507	PDH	HV Line Clash Mitigation	5	5	5	5	5	5	5
A109	PDL	LV Line Clash Mitigation	28	31	30	30	30	30	30
A159	ROH	HV Open Wire Conductor Repl. (km)	0.4	0.5	0.5	0.5	0.5	0.7	1.0
A164	ROL ROL ROL	LV Open Wire Conductor Repl. (km) Façade Rectification Program Undersized neutral replacement	1.9	2.6	3.0	3.0	3.0	3.0	3.0

4.3.5.4 *Asset Disposal*

Conductor and connectors do not contain hazardous materials and should be disposed of in accordance with JEM PO 1600 – Scrap Materials Policy.

4.3.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital works and customer initiated projects.

4.3.5.6 *Spares*

As part of the criticality assessment, consideration is given to the appropriate levels of spare equipment required to manage the risk of unplanned failures and to minimise unplanned supply interruptions which affects JEN's SAIDI and SAIFI reliability indices. The requirements for critical assets spares are assessed by following the Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). It was determined that adequate spares are maintained at Tullamarine depot and stock holdings are managed.

4.3.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determine the information required to manage and operate an Asset Class.

The Electricity Distribution ACS facilitates the safe, efficient and reliable delivery of electricity to JEN's customers. The information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

From these business objectives, it is possible to identify at a high-level the content of the business information systems' required to support these objectives (Table 4-28).

Table 4-28: Conductors and Connectors Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-29 identifies the current and future information requirements to support the Asset Class critical decisions and their value to the Asset Class.

Table 4-29: Conductor and Connectors Sub-Asset Class Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Conductors and Connectors application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied conductor and connectors and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Circuit Name - Circuit Voltage (i.e., ST, HV, LV) - Material - Conductor size/stranding - Neutral Conductor Material - Route Length - Date Installed - Owner - Feeder - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Automated assessment of thermal survey results • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-30 provides the information initiatives required to provide the future information requirements identified in Table 4-29. Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-30: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improve/review MAT Code definitions	Ability to align to AER service classification structure.	High	Precise definition
Improved Asset Attributes	Review current asset attribution fields to ensure attributes being collected are asset specific.	Medium	Appropriate and Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.4 UNDERGROUND DISTRIBUTION SYSTEMS SUB-ASSET CLASS

4.4.1 INTRODUCTION

The JEN underground distribution systems includes Sub-transmission (ST) cables, High Voltage (HV) distribution cables and Low Voltage (LV) cables and their ancillary equipment such as LV pillars and pits. The sub-transmission underground systems consist of 66kV and 22kV cables installed primarily as exit cables at terminal and zone substations. The HV underground systems consist of 22kV, 11kV and 6.6kV cables. The LV cable network distributes electricity to customers via pole and non-pole type substations. There is approximately 2,461km of underground distribution cable (ST, HV and LV) in service on the network with some cables installed as early as the 1920's and 1930's still in service.

In addition there is approximately 1,475.95km of underground service cable installed. This group of cables are those that are run from the service tee joints on the LV mains cables to the service pits, pillars or customers service and metering cubicles.

Underground cable systems provide a reliable and aesthetically pleasing means of energy distribution however, the construction of underground distribution systems is far more expensive than an overhead network but potentially less costly in terms of maintenance.

4.4.2 ASSET PROFILE

This section includes information about the type, specifications, life expectancy and age profile of the underground distribution systems in service across the JEN Electricity Network (JEN).

4.4.2.1 *Life Expectancy*

As prescribed in *ELE PR 0012 – Network Asset Useful Lives Procedure*, the applicable useful lives for the major elements of JEN's underground distribution systems are as follows:

Underground Cables and their Terminations:

- ST Oil Filled Cable 70 years
- ST, HV and LV Paper Impregnated Cable 70 years
- ST and HV Cross linked polyethylene (XLPE) 40 years
- LV XLPE 55 years

Pillars and Pits:

- LV Pillars 30 years
- LV Pits 40 years

The Network Asset Useful Lives Procedure considers asset lives based on good industry practice and specific JEN experience and represents the age of assets at which end-of-life replacement will be considered. JEN has referenced a number of reviews of asset useful lives from consulting agencies and discussions with other Distribution Businesses (DB's) to arrive at these asset lives.

4.4.2.1.1 Factors Affecting Life Expectancy

Factors that have a detrimental effect on the life of underground cable distribution systems include:

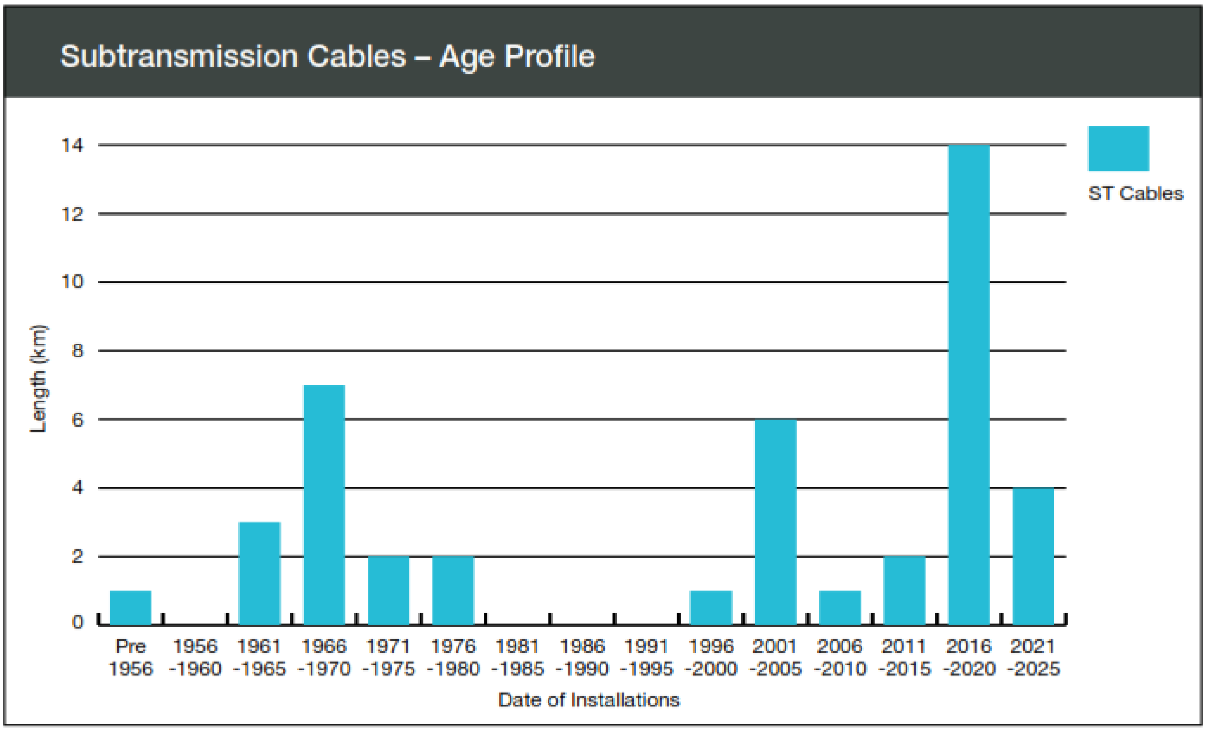
- Water ingress in cables;
- Partial discharge within cable insulation systems;
- Overload;
- Third party intervention (dig up of assets); and
- Workmanship.

4.4.2.2 *Age Profile*

The population of JEN's underground distribution systems can be characterised as follows (includes underground cables and their terminations):

• 66kV Sub-transmission Cable (total length)	27.45km
o Sub-transmission XLPE	20.08km
o Sub-transmission oil filled	7.37km
• 22kV, 11k and 6.6kV High Voltage cable (total length)	929.55km
o High Voltage Paper insulated	98.61km
o High Voltage XLPE insulated	830.94km
• Low Voltage Mains Cable (total length)	1,497.77km
• Low Voltage Service Cable (total length)	1,475.95km
• Pillars and Pits:	
o Low Voltage Pillars	2,373 assets
o Low Voltage Pits	87,680 assets

Figure 4-34: ST Cable Age Profile



N.B. The ST cable lengths reported above are the total lengths of single phase cable. (not the three phase circuit route length)

Figure 4-35: HV Cables Age Profile

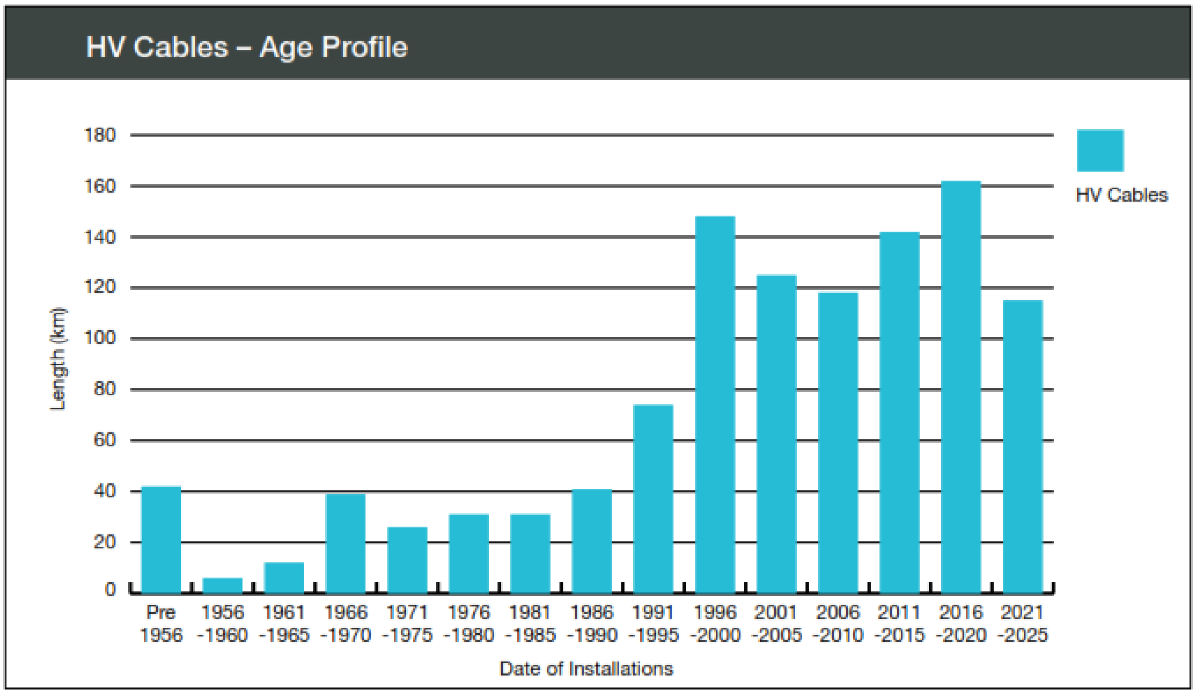


Figure 4-36: LV Mains Cables Age Profile

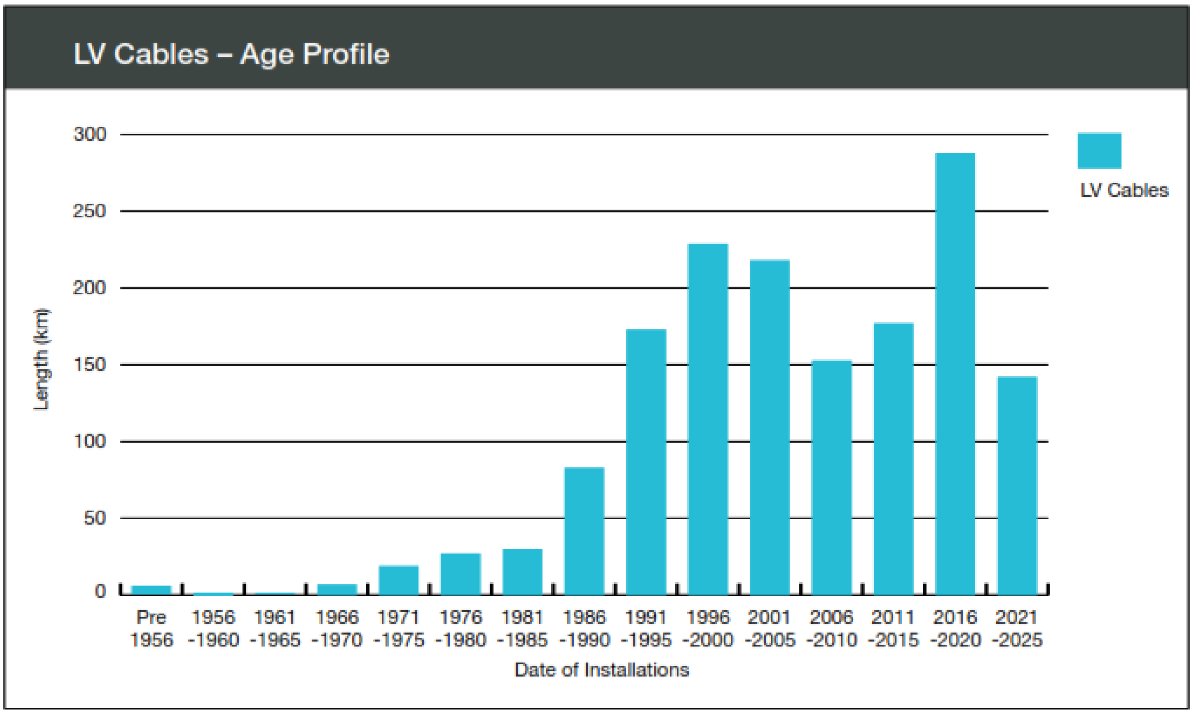
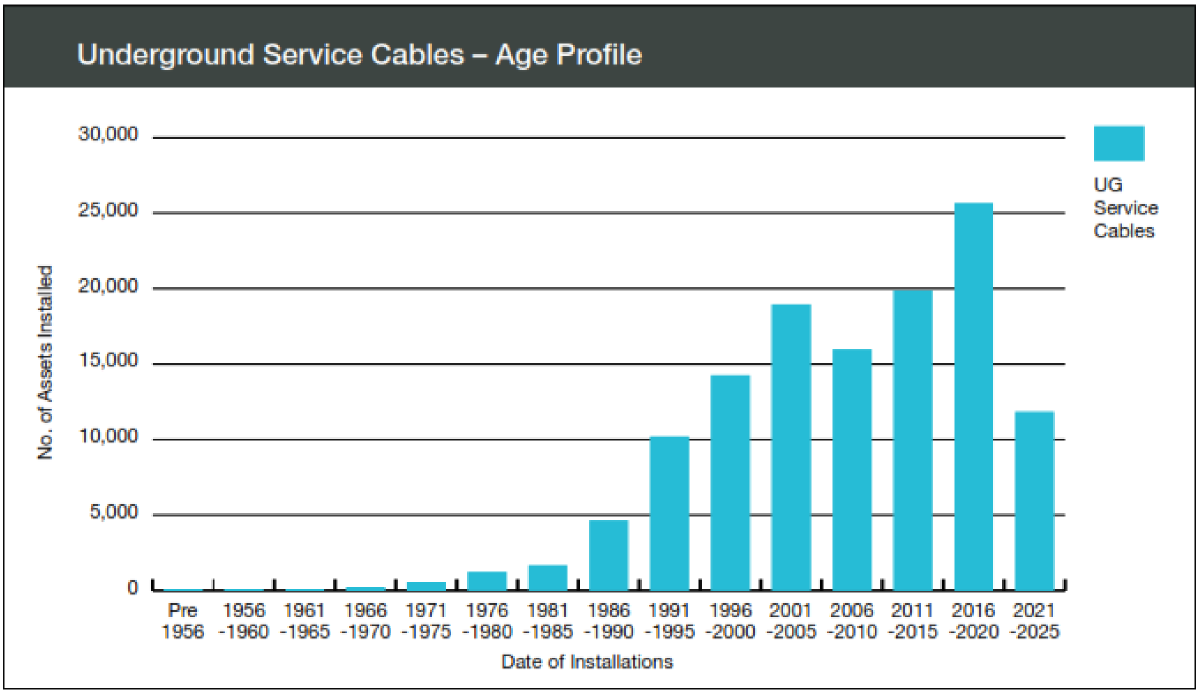


Figure 4-37: Underground Service Cables Age Profile



The increase in the rate of installation of HV, LV and service cables is due primarily to new residential estates installed within the JEN area of supply. All new estates are developed using Underground Residential Distribution (URD) systems.

4.4.2.3 *Utilisation*

The main function of the underground distribution system as a sub-asset class is to distribute electricity to customers in a more aesthetically pleasing and far more reliable manner as compared to overhead distribution networks. The underground distribution system now comprises approximately 45% of JEN's total network length.

The current range of cables in service and their application is listed below in Table 4-31.

Table 4-31: Current In Service Cable Application Guide

Usage	Type	Description
66kV U/G cable	38/66 kV, 1 Core 1200 mm^2 Aluminium Conductor, Corrugated Aluminium sheath, High Density Poly-ethylene outer sheathed	ST line cable for use as exit cables from zone substations or underground sections of ST lines.
HV U/G cable	12.7/22kV, 1 Core 35mm^2 Aluminium, Conductor, PVC outer sheath	This cable has only one PVC outer sheath and is most suitable for use indoor or kiosk distribution substations to connect between the transformer and the switch fuse unit. The cable can also be used for transformer droppers on pole substations.
	12.7/22kV, 1 Core 35mm^2 Copper, Conductor, PVC outer sheath	This cable is used in 22kV indoor distribution substations to connect between the transformer and circuit breaker (CB) unit.
	12.7/22kV, 3 Core 35mm^2 Aluminium, Conductor, High Density Polyethylene sheathed.	This cable was historically used as a distribution feeder cable in radial situations and is currently only used for repairs (no new installations). The cable cannot withstand the possible fault current when protected primarily by the zone substation CB and normally must be fuse protected.
	12.7/22kV, 1 Core 185mm^2 Aluminium Conductor, PVC outer sheath	This cable is used in 22kV zone substations as a jumper cable on capacitor banks and is also used to connect the station service transformer to the CB. A further application for this cable is to connect between the transformer and the circuit breaker in 11kV indoor substations.
	12.7/22kV, 3 Core 185mm^2 Aluminium Conductor, High Density Polyethylene sheathed	This cable is used as a distribution feeder cable in radial or spur situations.
	12.7/22kV, 3 Core 240mm^2 Aluminium Conductor, High Density Polyethylene sheathed	This cable is used for distribution feeder backbones which may run to either a cable head pole (CHP) or directly to a distribution substation or a customer's HV switchgear. Also suitable for use at 11kV
	12.7/22kV, 3 Core 300mm^2 Aluminium Conductor, High Density Polyethylene sheathed	This cable is used for Zone Substation feeder exits which may run to either a cable head pole or to a distribution substation. It may also be used as a feeder backbone where the desired feeder rating cannot be achieved using 240mm2 Al cable. Also suitable for use at 11kV

Usage	Type	Description
	12.7/22kV, 3 Core 300mm^2 Copper Conductor, High Density Polyethylene sheathed	This cable is used for Zone Substation feeder exits in congested locations where the desired ratings cannot be achieved due to mutual heating. It may run to either a cable head pole or to a distribution substation.
	12.7/22kV, 1 Core 630mm^2 Copper Conductor, High Density Polyethylene sheathed	This cable is used for heavily loaded zone substation feeder exits which run to either a CHP or directly to a customer's HV switchgear. It is also used for the connection of zone substation power transformers to the 22/11kV switchboard.
LV U/G mains cable	185 mm^2 cross-sectional area, 90 degree Sector Conductor, 4 Core	There are two main applications for these cables, there are: • As service cables, supplied from either overhead or underground mains, for customer supplies above 170 Amps diversified maximum demand (DMD). These cables may also be used as an alternative to the 50mm2 cable for supplies in the range of 150 to 170 Amps. • As a mains cable. The standard mains cable for medium density URD is the 185mm2 cable, however in some circumstances the 240mm2 may be used where long circuits are involved, particularly where there is unusually long distances prior to any service tapping.
	240 mm^2 cross-sectional area, 90 degree Sector Conductor, 4 Core	
LV U/G service cable	2 Cores of 16mm^2 (7/1.70mm) Annealed Copper. Colour Coding Black & Red. Flat construction.	These cables are for use as service cables for customer supplies up to 100 Amps D.M.D. For URD areas the 4 core cable is the standard service cable. When servicing from overhead distribution 4 core cable is used as standard. These cables are also used in the public lighting schemes.
	4 Cores of 16mm^2 (7/1.70mm) Annealed Copper. Colour Coding Red, White, Blue and Black.	
	4 Cores of 25mm^2 (7/2.15mm) Stranded Circular Compacted Annealed Aluminium. Colour Coding Red, White, Blue and Black.	These cables will be used on suitable new public lighting schemes in lieu of the 4 core 16mm2 UG cable.
	4 Cores of 50 mm^2 (19/1.78mm) Annealed Copper. Colour Coding Red, White, Blue and Black.	The main application for this cable is a service cable, supplied from overhead distribution in the range of 150 to 170 Amps DMD.

4.4.3 PERFORMANCE

4.4.3.1 *Requirements*

The requirements for cables and their accessories are set out in JEN's technical specification "66kV, 22kV, 11kV and LV Overhead Conductors and Underground Cables" which references a number of relevant Australian Standards (see Table 4-32 below). In order to ensure that cable systems achieve their designed operational ratings and ensure network reliability is maintained cable systems are installed in accordance with the requirements of the "Distribution Construction Manual Section 4".

JEN's internal construction standards ensure compliance with a number of regulations that cover the installation of underground cable systems. These standards include design parameters which address areas including clearances, equipment types, ratings and the recording of asset data including asset location (Before You Dig Australia data).

All underground assets are assigned ratings (including cyclic ratings) that are based on the type of cables, the method of installation and the load profile. In addition, fault ratings for both the conductors and screens of cables are specified to ensure cables are matched to the networks fault levels. Refer to Distribution Standard Manual Section 4.5 for various cable rating details.

The monitoring and optimisation of the performance of the underground cable distribution systems occurs via the use of the following systems and programs:

- Feeder loads are monitored and managed via SCADA;
- The LV cable network parameters (loads, voltages and impedances) are monitored via the JEN Analytics application using AMI data;
- Faults and failures are monitored via the OMS;
- Cable termination defects and maintenance issues are identified though Asset Inspection and Enclosed Substation Inspection Programs;
- Defects and failures are monitored via the Plant Maintenance notification systems (SAP)
- Monthly asset performance review meetings review performance and faults.

Table 4-32: Cables and Accessories - Relevant Australian Standards

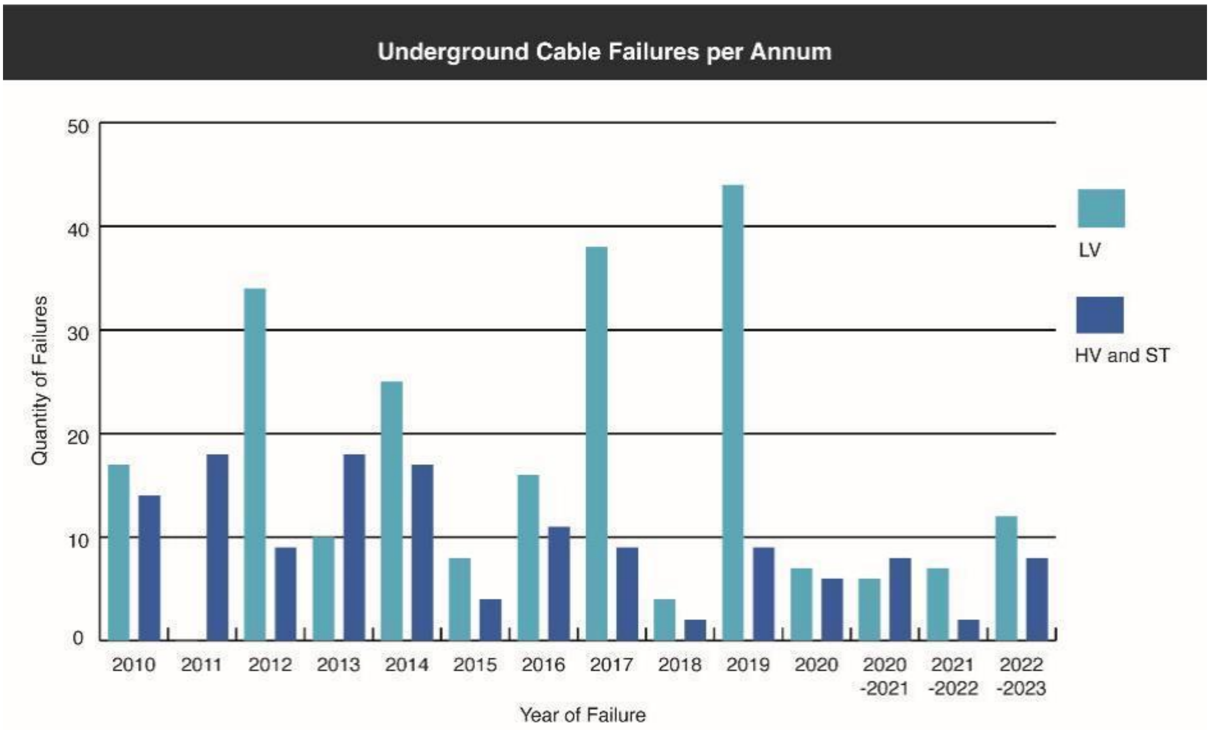
Standard	Title
AS/NZS 1125	Conductors in Insulated Electric Cables
AS/NZS 1429.1	Electric Cables – Polymeric insulated Part 1 3.6kV – 36kV
AS/NZS 1429.2	Electric Cables – Polymeric insulated Part 2 36kV – 170kV
AS 2629	Separable Insulated Connectors for Power Distribution System Above 1kV
AS/NZS 4026	Electric Cables – For Underground Residential Distribution Systems
AS/NZS 5000.1	Electric Cables – Polymeric Insulated Part 1 up to 1.2kV

4.4.3.2 *Assessment*

The principal method of assessment of the performance of the underground distribution system is based on the monitoring of asset failures and maintenance notifications. The on-line or in-service monitoring of the condition and performance of underground cables is limited to the inspection of the visible parts of these systems. That is mainly the cable terminations and many of these are also not visible. There is some ability to monitor cable condition on-line, but this is limited, and comprehensive diagnostic condition assessment generally involves taking cables out of service and often the physical disconnection of the cable. For this reason, these types of tests are generally only performed at the time of commissioning or following a cable fault or incident. They are not suited to the routine assessment of cable condition.

The failure history associated with individual sections of cable is a key indicator of condition. It should be noted that the LV faults includes both faults on LV mains cables and LV service cables (i.e., the cables that are teed of the mains cable to generally supply a pit).

Figure 4-38 Underground Cable Failure Data



4.4.4 RISK

4.4.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is also used to rank importance of dissimilar sub-asset classes (e.g., transformers and surge diverters) to identify areas where risk should be managed first, and control measures implemented.

The underground distribution system sub-asset class has an asset criticality score of AC3 (Significant) due to the consequence of underground cable failure and JEN's limited ability to respond to some types of faults (e.g., leaks in the oil insulating system in the case of ST cables) due to the availability of skilled technicians.

Several sections of JEN's ST oil filled cables have been identified as at risk due to the limited availability of skilled maintenance crews, either external or internal. This impacts JEN's ability to respond to a fault or leak in the oil insulating system. In addition, pressurised cables take a long time to repair, and leaks can be detrimental to the environment.

A subsection of JEN's underground network has been identified as at risk to flood damage. Revised flood risk modelling conducted by Melbourne Water following the 2022 Maribyrnong River flood has reclassified the location of a number of JEN assets as a high-flood risk zone.[2][3] This creates a number of risks including; the potential for frequent service interruptions during flood events substantial damage to equipment, requiring costly repairs or replacements which would likely be recovered from customers via cost pass through and health and safety risks for JEN staff as flood damage may reduce the integrity of the assets. Relocation of these assets that are in flood zone risk areas needs to be undertaken in the next regulatory period to address the risks to our network and our customers.

Good underground network design ensures that customer outages are typically minimised through HV switching and the isolation of damaged cable sections. JEN has access to appropriately skilled technicians so that the maintenance and repair of modern cable systems can be undertaken without delay, hence modern HV cable systems can be considered medium criticality.

LV cable faults cause limited customer outages and like the modern HV cable systems there are maintenance crews readily available to repair the faults in a timely manner hence LV cables are considered low criticality.

4.4.4.2 *Failure Modes*

The failure modes for this sub-asset class include:

4.4.4.2.1 ST/HV cables

Insulation failures are the most common type of cable failure. These can be caused by partial discharge associated with voids in insulating material and the ingress of moisture. "Water treeing" in XLPE cables leads to insulation breakdown and puncture.

In oil impregnated paper insulated lead sheathed cables, the aging of the insulation system is due to the presence of oxygen, moisture and heat. The lead sheath provides the moisture barrier in these cables. Corrosion of the lead sheath is commonly caused by electrolysis associated with DC traction systems. This leads to the failure of the lead sheath and consequently moisture ingress and insulation failure. Physical damage also results in cable failure either immediately or after moisture enters the damaged cable.

Cable failures most commonly occur at joints and terminations as they are areas where the control of the electrical stresses can be problematic.

Exceeding the cyclic and emergency ratings of cables or poor thermally conductive bedding materials can cause severe overheating of cable insulation systems. This can result in insulation system failures (for example the infamous Auckland 110 kV multiple cable failures).

[2] Expert Panel Review of Flooding Risk, [Progress update on the Maribyrnong River Flood Review - Release of Report | Maribyrnong River Flood Review | Let's Talk | Melbourne Water]. October 2022
[3] These assets are located within the Marybong River's 1% Annual Exceedance Probability (AEP) floodplain, this is commonly recognised as 'high flood risk' with additional guidance for building standards within this area. Further details can be found here; Victorian Government, [Guidelines for Development in Flood Affected Areas], February 2019

Pitch filled metal enclosed cable terminations have a history of catastrophic rupture resulting in the projection of pieces of metal, porcelain and pitch. These are age related failures associated with the failure of the sealing systems on these cable boxes (CABUS types).

4.4.4.2.2 LV Cables and Terminations

Similar modes of failures for ST/HV cable apply for LV cables.

There are a range of LV cable terminations on the JEN where the inner colour coded plastic insulation has not been protected from the effects of UV light. These are cable terminations that have not been installed in accordance with the standards for termination of these cables. This insulation is not UV light stabilised resulting in the insulation cracking and falling off resulting in bare conductors at the termination point. This is a severe safety risk and potential for flashovers exist due to the absence of the cable insulation.

4.4.4.3 *Current Risks*

4.4.4.3.1 HV XLPE Cable

HV XLPE cable installation began in the mid 1970's. Worldwide research has shown that many of the cable faults experienced on cables after 10 - 15 years in service are attributed to insulation degradation through water treeing. The presence of water trees in cable insulation is known to decrease the residual life of the cable.

Water may enter the cable during initial installation or as a result of subsequent sheath damage. Furthermore, the manufacturing process of XLPE cable changed from steam curing to dry curing around 1985. Steam curing introduced water to the XLPE insulation at the point of manufacture which promotes the growth of water trees when the cable is electrically stressed. This has had a significant impact on the life expectancy of these cable types.

4.4.4.3.2 Paper Insulated (MI type) HV Cable

This cable type was predominantly installed on the 11kV and 22kV networks prior to the 1970's, however, was still used up to the 1990s. The cable utilises mass impregnated (MI) paper as the insulating medium. Many of the older cables were originally operated at 6.6kV and converted to 11kV. The early cable designs used oil impregnated paper, but these suffered oil migration leading to the drying out of the papers. Advances in cable design resulted in the development of MI type cables that were non-draining. Many of these sections of cable are short (typically 200 m) and are used as feeder exit cables.

There appear to be two main causes of MI type cable failure namely:

- Failure of paper insulation due to oil migration over the life of the cable, leaving paper dry and brittle. Failure is particularly evident in existing cable joints or when new joints are installed. Due to the condition of the insulation in these cables, the risk of failure is significantly increased when cables are physically disturbed or handled.
- Failure due to moisture ingress resulting from lead sheath fatigue and corrosion. This problem is particularly evident in the inner suburban areas that are prone to electrolytic corrosion due to the proximity of tram and rail systems.

Some sections of this type of cable have been identified as having excessive failure rates. For instance, some cable has experienced failures attributed to moisture ingress as a result of lead sheath fatigue and electrolytic corrosion.

4.4.4.3.3 HV CABUS Type Outdoor Cable Terminations

These terminations were installed on the 6.6kV, 11kV and 22kV networks. They are a pitch filled terminations housed in a cast iron cable box and many have failed catastrophically which can result in personnel injury and damage to public property. They are particularly hazardous when failure occurs as the cast iron can shatter and is often expelled over a wide area. The root cause of failure of these boxes is the ingress of moisture in the pitch filled cable boxes resulting in the deterioration of the ageing paper insulation. Over the years paper can become brittle and absorb moisture which reduces its dielectric strength giving way to partial discharges. Degradation of paper also occurs from heating of the copper conductor, especially during times of peak demand. These partial discharges break down and weaken the paper insulation. Once the insulation breaks down the phases flash over and generate a 3-phase fault.

4.4.4.3.4 HV and LV Pitch Filled Fabricated Metal Outdoor Cable Terminations

These terminations are of similar vintage to the CABUS type HV terminations. These terminations are also pitch filled but housed in a fabricated metal box. Failure of this type of termination is not as hazardous as the metal box does not shatter but can split expelling pitch and other debris. Failure is often associated with the effects of corrosion and moisture ingress. The consequences of failure are far less severe compared with CABUS terminations in terms of risk of injury to the general public however the potential for injury is still present. With LV terminations the impact on reliability of supply is minimal.

4.4.4.3.5 LV Outdoor Terminations with Exposed Conductor Insulation

There have been a number of reports of LV PVC and LV XLPE cable terminations deteriorating in service as the result of the effects of UV radiation. These terminations have been incorrectly terminated such that the LV cable cores have the inner phase coloured insulation remaining exposed. As this insulation is non-UV resistant, it can deteriorate and expose bare LV conductors. This is a potential safety hazard (especially on concrete poles) and also a potential cause of LV faults due to short circuits between the LV phases of the cable. The construction standard requires that when terminating these cables outdoors, each of the cores has to be covered with a UV resistant heat shrink sleeve.

4.4.4.3.6 LV Pillars and Cabinets

A variety of LV pillars have been installed on the underground distribution system. These include paralleling pillars, paralleling service pillars and service pillars. These pillars are generally installed in Underground Residential Distribution (URD) estates with the latter two confined to older installations where individual lots are serviced from the pillar instead of a pit. In addition, there are LV cabinets used to provide multiple LV feeders in industrial and commercial areas. These require ongoing inspection to ensure they remain secure and if damaged are repaired.

4.4.4.3.7 Cable Sheath Voltage Limiters (SVL’s)

In order to manage the voltages induced on the screens of single core 66kV cables, special cable screen earthing arrangements are used in conjunction with SVL’s. The condition of the SVL’s needs to be monitored.

4.4.4.3.8 66kV Oil Filled Cables

There are a small number (6.92km) of 66kV oil filled cables installed that form part of the ST network. The oil in the cable forms part of the insulation system and is maintained under pressure. In the event that the lead sheath on these cables is damaged then oil can leak out of the cable resulting in a pressure drop and associated alarm. Pressure alarms need to be monitored via SCADA and manually checked regularly.

4.4.4.3.9 22kV XLPE Cable Joints

JEN has experienced elevated failure rates on 22kV XLPE cables that were installed in the 1990's. These are relatively new cables, and the cause of the underground cable faults has been attributed to joint failure. Failures have occurred on feeders supplied from AW, ST and COO. All of the recent joint failures occurred on cables that were installed between the years 1993 and 1999. The cable failures also all occurred at below rated current and before their expected engineering end of life.

It has been concluded that poor workmanship, issues with the size of the conductor crimp sleeve, and the cross-sectional area of the associated conductor contributed to the failures. JEN is aware that at that time the standard for 22kV cable was changed and conductor size was based on conductivity whereas previously the standard had directly specified conductor cross-sectional area. Consequently, the actual conductor in the cable could have a reduced cross-sectional area but still satisfy the cable performance requirements by varying the conductor alloy composition. The result is that the standard crimp sleeve sizes were too big for the supplied conductor cross-sectional area. This has resulted in joints that can overheat and fail when loaded. This was a particular problem for the 185mm^2 HV cable as the joint manufacturer had designed the joints to take certain cable size ranges and the 185mm^2 conductors were at the low end of the size range resulting in poor crimp quality.

4.4.4.3.10 Third Party Intervention

Another source of failure for cables is accidental third party intervention (i.e., third party damaged or dig in of JEN underground assets) or deliberate third party intervention (i.e., copper theft, primarily of public lighting cables in new URD estates).

4.4.4.3.11 Voltage Stress from REFCL System Operation

The use of Rapid Earth Fault Current Limiter (REFCL) technology to mitigate bushfire risk by further reducing phase to earth fault current has further implications on the life expectancy of HV cables, cable joints and cable terminations under fault conditions. HV cable systems installed on HV feeders associated with zone substations where a REFCL system will experience high phase to earth voltages (phase to phase voltages) for an extended period under fault conditions or annual REFCL performance testing. High phase to earth voltages would accelerate water treeing and insulation breakdown resulting in more HV underground assets failures which also impact on network reliability and STPIS.

4.4.4.4 *Existing Controls*

4.4.4.4.1 HV XLPE Cable

The JEN cable specification was changed in 2008 and consequently all new HV cable is supplied with water tree retardant XLPE insulation. The performance of this modified XLPE insulation has been documented overseas and found to impede the formation of water treeing in the insulation.

4.4.4.4.2 Paper Insulated (MI type) HV Cable

Proactive replacement has been undertaken to address MI type HV cable failure issues based on failure rates.

4.4.4.4.3 HV CABUS and Metal Fabricated Type Pitch Filled Outdoor Cable Terminations

These types of cable terminations have a history of catastrophic failure. JEN has implemented a prioritised proactive replacement program to manage the risk associated with the in-service failures of these terminations. The aim of the program is to retire and replace all remaining CABUS cable terminations and all remaining HV fabricated metal cable box terminations.

The project has reached a stage where all 22kV installations have been replaced due to their criticality. The conversion of the Preston and East Preston Zone Substations from 6.6kV to 22kV means that all of the terminations in these areas have been retired or will be at the completion of the conversion program. This leaves the program with approximately 50 terminations to replace in the PV, ES, FT and NS supply areas. This will continue until all of these terminations have been retired.

4.4.4.4.4 LV Outdoor Terminations with Exposed Conductor Insulation

The Asset Inspection Manual has been modified to document the inspection requirements. These terminations are to be rectified as they are found.

4.4.4.4.5 LV Pillars and Cabinets

Replacement programs have been completed which targeted some types that were made of materials containing asbestos.

4.4.4.4.6 Cable Sheath Voltage Limiters (SVL's)

SVL's are installed to protect the cable sheath from damage that may occur due to high screen voltages being induced in the screens by fault currents passing through the cables. The SVL's also prevent the flow of induced earth currents which can de-rate the cable if not correctly managed.

4.4.4.4.7 66kV Oil Filled Cables

Fault locating tools have been purchased and have aided in the location of sheath faults. Subsequently a number of these faults have been repaired.

Given the low number of 66kV oil filled cables on the JEN, the age of these cables, and the lack of in house resources and expertise to deal with defects or faults, the cable management strategy will be updated to reflect the active replacement of these cables over the next regulatory period (2026-2031).

4.4.4.4.8 22kV XLPE Cable Joints

Asset replacement projects are being implemented in both a reactive and proactive manner to manage this issue.

4.4.4.4.9 Third Party Intervention

Accidental dig ups occur from time to time and are mitigated via "Before You Dig Australia" campaigns and warning signs that declare there are underground assets in the area.

Copper theft has become an increasingly common occurrence, particularly for public lighting cables in new URD estates. The same location is often targeted multiple times. Four core 25mm Aluminium XLPE cable is used as a replacement for stolen public lighting cable. All copper theft incidents are being reported to the Police.

4.4.4.4.10 Voltage Stress from REFCL System Operation

HV cable systems installed on HV feeders associated with zone substations where a REFCL system will experience high phase to earth voltages (phase to phase voltages) for an extended period under fault conditions or annual REFCL performance testing. In preparation for the implementation of REFCL systems, all HV paper insulated cables and pitch filled outdoor cable terminations will be replaced; the feeders will be stress tested and any HV cables failed during the tests will be replaced. This control will lower the probability of HV cable system assets failures after REFCL systems are put in service and reduce the risk on network reliability and STPIS.

4.4.4.5 *Future Risks and Opportunities*

The JEN faces a risk due to the lack of in-house technical expertise required for promptly repairing or jointing oil-filled cables in case of sheath or cable faults. Outsourcing is necessary for this expertise. To mitigate this risk, a contract is in place with a service provider to provide oil top up, fault and emergency services for oil filled cable. A few 66kV cables with sheath faults have been pinpointed on the network, necessitating precise fault location for economical repairs. The most effective strategy moving forward is to actively replace these cables during the next regulatory period.

There are numerous cable monitoring tools available to assist with the condition monitoring of underground cables. The efficiency and practicality of these systems is currently being assessed. A screening program that can be simply applied without undue disruption of the network and give an indication of deteriorating cable condition is needed.

A cable management strategy is to be developed to optimise the proactive and reactive use of testing equipment. The cable management strategy will document the requirements to undertake a testing regime (both online and offline testing), as well as a record management system to capture and proactively assess cable condition.

Future analysis of data captured by this strategy will provide information on developing trends in cable condition. This will enable identification of developing conditions and prioritise the ongoing monitoring of cable condition and the proactive maintenance or replacement activities.

4.4.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy covers time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance.

4.4.5.1 *Creation*

Underground cable distribution systems are installed and extended as required for new customer projects and where needed to augment the capacity of the distribution network. This is the preferred method for the distribution of electrical energy due to the superior reliability of underground network assets and the environmental and aesthetic advantages. Underground distribution systems are mandated for all new residential development. There is still a significant additional cost associated with underground systems over the cost of overhead assets however the differential has decreased over the years.

4.4.5.2 *Asset Operation and Maintenance*

There are four (4) life cycle management strategies applied to the operation and maintenance of the underground distribution systems sub-asset class:

- Asset Inspection;
- Preventative Maintenance;
- Reactive and Corrective Maintenance; and
- Run to Failure.

This group of assets are operated and monitored via the SCADA system and via the JEN Analytics application applied to the AMI data. This is used to monitor the operational state and loads applied to the various elements of the ST, HV and LV underground assets.

4.4.5.2.1 Asset Inspection

4.4.5.2.1.1 66kV XLPE Cables

A sheath integrity test is performed on 66kV XLPE cables of significant length every two (2) years. This test confirms the integrity of both the metallic sheath and outer PVC and HDPE sheaths.

The Sheath Voltage Limiters (SVL) are also inspected and tested every two years.

It is recommended that this program be timed to coincide with the oil filled cable inspections as described below.

4.4.5.2.1.2 66kV Oil Filled Cables

A sheath integrity test and SVL test are scheduled every two years as per 66kV XLPE cables.

Oil pressure is checked monthly to confirm that it is within limits. Every two years the oil pressure alarm system check shall be performed to ensure the integrity of the system.

Maintenance plans are established in SAP that require the periodic scheduling of the above inspections and tests.

4.4.5.2.1.3 HV XLPE Cables

There is limited efficient cable condition monitoring/inspection for these types of cables. This type of asset is replaced based on failure history and the results of diagnostic tests following asset failure. Currently they are managed on a run to failure basis.

4.4.5.2.1.4 Paper Insulated (MI) Type HV Cable

As for XLPE cables there is limited cable condition monitoring currently performed. Similarly, this type of asset is replaced based on failure history and the results of diagnostic tests following asset failure. They are managed on a run to failure basis.

4.4.5.2.1.5 HV and LV Outdoor Cable Terminations (Metal Enclosed)

The condition of these terminations is monitored via the Asset Inspection and Substation Inspection programs. The inspection is looking for signs of deterioration such as rust or leaking insulating pitch. Any terminations identified as in poor condition and likely to fail shall be reported and programmed for replacement. Currently there is a program to phase out HV Metal Box Outdoor cable terminations.

4.4.5.2.1.6 LV Outdoor Cable Terminations with Exposed Conductor Insulation

The inspection of these assets is specifically looking for cases where the inner conductor (usually coloured to match the phase) insulation is exposed to UV light (sunlight) which causes deterioration. The construction standard requires that each core is covered by a UV resistant heat shrink sleeve to protect the insulation from UV damage. Although there is low risk associated with reliability of supply, the safety risk is unacceptable. On this basis a pro-active approach has been taken to identify and inspect these terminations with a planned repair program. The majority of these have been rectified, however if any of these are discovered a notification shall be raised against the terminations and scheduled for repair.

4.4.5.2.1.7 LV Pillars and Cabinets

Pillars and cabinets are to be inspected on a 3-year cycle in the HBRA and a 4-year cycle in the LBRA coinciding with various asset inspections or scheduled maintenance of the distribution substation that supplies the pillar or cabinet. The following list details the main areas of inspection:

- Damaged or cracked pillar cover or damaged and corroded cabinet enclosure;
- Damaged, broken or missing stainless steel cord or other device used for locking pillar;

- Damaged cabinet lock; and
- Confirm that surrounding landscape does not prohibit normal operational access to pillar or cabinet

For further details on pillar inspection and management refer to "JEN MA 0500 - Asset Inspection Manual".

The development of a comprehensive condition monitoring strategy for cables will help identify the health of the cables and inform a proactive approach to the maintenance and replacement of this sub-asset class.

4.4.5.2.2 Preventative Maintenance

4.4.5.2.2.1.1 Proactive Retirement

Proactive retirement of underground cables is a less common activity and will generally take place as a result of network augmentation due to redevelopment of a network area or expansion of the surrounding supply network.

4.4.5.2.2.1.2 Proactive Replacement

This strategy aims to achieve high reliability whilst balancing safety and performance considerations in establishing an inspection and planned replacement program. Planned replacement programs are specifically focused on stabilising asset performance through retirement of underground cables with identified poor performance issues.

4.4.5.2.2.2 Reactive and Corrective Maintenance

Reactive and corrective maintenance is carried out when faults occur or after asset inspection programs identify any required maintenance, resulting in the repair of:

- Cable and their termination accessories; and
- Pillars and Pits.

4.4.5.2.3 Run to Failure

This is an appropriate lifecycle management strategy when the consequences of failure do not include any risk of injury or harm and where the failure rate is low. This asset subgroup is reliable, and the failure rates are low compared to the overhead parts of the network. In general cable systems are not accessible and therefore their failure does not occur in the public domain and thus the failure of the buried parts of these assets has in general no safety consequences. There are however significant consequences in terms of network reliability when a failure occurs.

A review of maintenance notifications reveals that there have been HV cables and LV cables that have been repaired or jointed as a result of an in-service failure due to the following causes:

- Accidental human intervention by JEN/contractor;
- Accidental human intervention by others;
- Component failure;
- Electrical failure / deterioration;
- Mechanical failure / deterioration; and
- Underground dug up by others.

Three of these six failure causes relate to interference with underground assets. When assessing the intrinsic performance of this sub-asset class these failure causes are discounted.

4.4.5.3 *Underground Distribution System Forecast Replacement Volumes*

As detailed in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

Table 4-33 lists the forecast replacement volumes for underground distribution system elements from 2025 to 2031.

Table 4-33: Replacement Volumes – Underground Distribution Systems

Unique ID	Service Code	Underground Distribution Systems	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A208	RUA	HV U/G Cable Replacement (m)	38	43	328	321	328	321	328
A209	RUA	Replace Metal Trifurcating Boxes	5	-	-	16	11	12	5
A210	RUC	LV U/G Cable Replacement (m)	179	204	200	200	200	200	200
A211	RUF	Pillar to Pillar	5	5	5	5	5	5	5
A239	RUH	HV U/G Termination Replacement	24	24	20	20	20	20	20
A213	RUL	LV U/G Termination Replacement (service pit replacement)	24	25	25	24	24	25	25
A 213	RUL	LV U/G Termination Replacement	42	47	45	45	45	45	45
A354	RUS	ST U/G Cable Replacement – BLTS-TH2 Oil Filled Cable (m)	-	-	-	-	-	82	100
A357	RUS	ST U/G Cable Replacement - YVE-NT Oil Filled Cable (m)	-	-	-	-	-	143	171
A358	RUS	ST U/G Cable Replacement - BLTS-NT Oil Filled Cable (m)	-	-	-	-	-	84	101
A359	RUS	ST U/G Cable Replacement - TTS-CS-CN Oil Filled Cable (m)	-	-	-	-	170	204	-
A360	RUS	ST U/G Cable Replacement - TTS-NEI/NH-WT Oil Filled Cable (m)	-	-	-	139	167	-	-
A361	RUS	ST U/G Cable Replacement - WMTS-FE1 Oil Filled Cable (m)	-	-	-	757	-	-	-

4.4.5.4 *Asset Disposal*

Underground cables typically do not contain hazardous materials and should be disposed of in accordance with JEM PO 1600 - JEN Scrap Materials policy.

4.4.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.4.5.6 *Spares*

Spare underground cables and their associated components and accessories are stored at JEN's various depots for fault and emergency use. If a substantial fault occurs on these cables, a specialist contractor will need to be contacted to repair the cable as there is no expertise within the business to repair this type of cable.

4.4.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determine the information required to manage and operate an Asset Class.

The Electricity Distribution ACS facilitates the safe, efficient and reliable delivery of electricity to JEN's customers. The information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives (Table 4-34).

Table 4-34: Underground Distribution Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Network loading data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-35 identifies the current and future information requirements that support the Asset Class's critical decisions and their value to the Asset Class.

Table 4-35: Underground Distribution Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Underground distribution acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of underground cables and accessories and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Operating voltage - Construction type - Conductor material - No of cores - Cross-section area - Date Laid - Date Removed - Computed Length - Feeder - Owner • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Design voltage • Cable position • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-36 details the information initiatives required to provide for the future information requirements identified in Table 4-35. Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-36: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improved Asset Attributes	Review current asset attribution fields to ensure attributes being collected are asset specific.	Medium	Appropriate and Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.5 POLE TYPE TRANSFORMERS SUB-ASSET CLASS

4.5.1 INTRODUCTION

Pole type transformers and their associated circuits are the principal asset at the overhead networks interface with domestic, commercial and industrial customers. These facilitate the customers energy supply and export requirements.

Included in this sub asset class are pole mounted line voltage regulators. These are pole mounted installations that maintain the primary voltage on long rural feeders to ensure the maintenance of supply quality for rural customers. They are included in this asset class due to their similarity in terms of asset management to pole mounted distribution transformers. Currently JEN has two of these installations, one three phase installation and a single phase installation.

To ensure that this asset class successfully delivers on our values requires distinct performance measures, condition based monitoring, inspection programs, risk analysis and customer interaction, all of which are described in this sub-asset class document.

The key factor determining the pole type transformers performance is its capacity to interface with the various types of equipment customers connect to the network. An appropriately rated transformer along with an electrically strong network will deliver a quality electricity supply that meets customer demands reliably and safely.

The transformers principle purpose is to convert High Voltage (HV) of 22kV, 11kV or 6.6kV to a nominal supply voltage of 400/230V. These voltages are then delivered to our customers through the low voltage distribution network.

Transformer selection is determined by the type and size of load it will supply. The load capacity of the transformer is expressed by its kVA rating, JEN pole type transformers vary in size from 10kVA up to 500kVA.

JEN operates 4,238 pole type transformers. The number of customers supplied by these individual transformers ranges between 1 and 370 customers.

4.5.2 ASSET PROFILE

4.5.2.1 *Life Expectancy*

As prescribed in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for pole type transformers is as follows:

- Pole type transformer - 50 years

The above procedure considers asset lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has undertaken a number of reviews of asset useful lives with consulting agencies and held discussions with other Distribution Businesses to ensure assigned asset lives are realistic.

4.5.2.2 *Age Profile*

There is a total of 4,238 single and two pole transformers in service within JEN. The chart in section 4.6.2.2 shows the age distribution of pole type transformers. The chart shows that the majority of transformers are less than 50 years old with only 6.3% of the transformer population older than 50 years.

4.5.2.3 *Utilisation*

A pole type transformers operating capacity is determined by its cyclic rating. Cyclic ratings are dependent on load types or load profiles, consequently the loading of a pole type substations is assessed against its cyclic rating rather than its nameplate rating. Refer to Table 4-37 for details.

Table 4-37: Pole Type Transformer Cyclic Ratings

Nameplate (kVA)	Load Type	Summer Rating (kVA)	Winter Rating (kVA)
≤100	Residential	119	141
≤100	Comm/Industrial	110	124
200	Residential	238	282
200	Comm/Industrial	220	248
315	Residential	374	443
315	Comm/Industrial	338	391
500	Residential	593	704
500	Comm/Industrial	537	621

The rating table above is a guide only. For further details, refer to the JEN Transformer Rating (Zone Substation and Distribution) plant guidance document.

The utilisation of distribution substations is reviewed periodically as part of the Distribution Substation Augmentation Program. For details, refer to the Distribution Substation Augmentation, Network Development Strategy (Doc No. ELE PL 0017) and the Network Performance Plan 2021-2025 (Doc No. ELE-999-PA-IN-002). Substation loads are monitored via the JEN Analytics (JENA) application. Proactive replacement of pole type distribution substations is driven by organic load growth and following a customer's request for increased supply. The transformers which are taken out of service are then assessed and refurbished if suitable.

4.5.3 PERFORMANCE

4.5.3.1 *Requirements*

The Electricity Safety (Management) Regulations 2019 require that JEN comply with its internal technical standards. JEN's internal standards reflect the Electricity Safety (Network Assets) Regulations 1999. These regulations where used as the basis for JEN's Electricity Safety Management Scheme (ESMS) to which the JEN assets are designed, constructed and maintained. JEN has conducted a Formal Safety Assessment as part of its ESMS submission to Energy Safe Victoria (ESV) which incorporated a risk assessment of the adequacy of JEN's current internal technical standards.

Pole type transformers are the major component of a pole type substation. The standards for the construction of pole type substations are prescribed in the "Distribution Construction Manual, Volume 2, Section 3.0 Substation and Plant construction". These standards include design parameters such as clearances, animal proofing, equipment types, ratings and minimum mounting height.

All distribution transformers and their component parts are designed, manufactured and tested in accordance with the Australian Standards set out in Table 4-38 and as prescribed in "JEN Electricity Networks (Vic) Ltd 22kV, 11kV & 6.6-11kV, 16 kVA to 2000 kVA Distribution Transformers, Technical Specification".

These standards include design parameters such as voltage withstand, no load losses, thermal cyclic loading characteristics, and voltage tolerances.

Table 4-38: Relevant Australian Standards

Standard	Title
AS 1767	Insulating liquids - Specification for unused mineral insulating oils for transformers and switchgear
AS 2374	Power transformers - Minimum Energy Performance Standard (MEPS) requirements for distribution transformers
AS 60076 (series)	Power transformers – Parts 1 to 10
AS 2629	Separable Insulated Connectors for Power Distribution System Above 1kV
ENA DOC 007- 2006	Specification for Pole Mounting Distribution Transformers

The primary purpose of the transformer is to provide a nominal LV supply to customers that complies with the Victorian Electricity Distribution Code of Practice (VEDCoP) with respect to Section 4 Quality of Supply (QOS) and Section 5 Reliability of Supply (ROS) requirements.

Network related and customer initiated QOS and ROS issues are dynamic in nature, they develop as a result of the localised and cumulative increasing demand that customers load and generation places on the LV networks. As customers electrical equipment is modernised; its impact upon and reliance on the networks compliance with the regulated QOS and ROS requirements increases. Reduced supply quality can have perceived and/or real impacts on the operation and lifecycle of connected electrical equipment. Transformers play a vital role in maintaining a stable and reliable supply. JEN must therefore ensure it responds to these increasing needs and continues to remain compliant by matching the networks capacity to its customers load demands.

Pole mounted line voltage regulators have similar requirements to pole top transformers. The significant difference is that these devices are fitted with on load tap changers and a voltage control system to facilitate a dynamic response to variations in the line voltage. This feature is used to ensure compliance with the QOS requirements of the Distribution Code for customers downstream of the voltage regulator.

4.5.3.2 *Assessment*

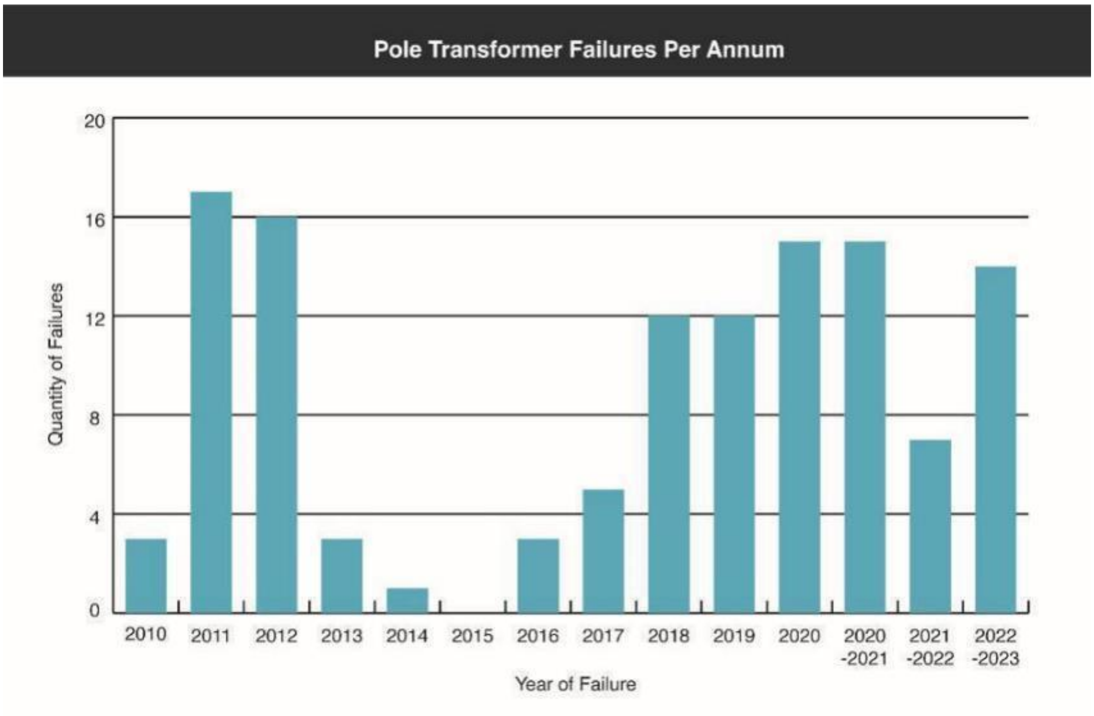
The operational performance of the pole top transformer population is assessed through transformer failure rates, supply quality complaints and substation load profiling.

Transformer failures generally result in customer supply outages and can lead to public and operational risks, including oil spills and fire starts. Outages are captured by JEN's OMS where event details and disruption times are recorded. Failure modes and rates are monitored through SAP notifications to identify equipment reliability issues.

Between 2010 and 2022 pole top transformer in-service failures that require transformer replacement have averaged approximately 11 failures per annum and the failure rate trend line is flat. Figure 4-39 indicates the annual failure rates. In addition to these in service failures, a number of transformers will be replaced based on condition assessments to address issues such as oil leaks or corrosion related defects.

There have been numerous failures as a result of transformer overloads, faulty connections and external factors such as lightning but the transformers themselves are generally very reliable with no evidence of systemic problems affecting reliability.

Figure 4-39: Pole Type Transformer Failures



Quality of supply issues directly caused by transformers generally occur as a result of overload, an overload occurs when there is an excess of customer load or reverse energy flow due to embedded generation, relative to the transformers rating.

Transformer overloads are being proactively assessed using the JEN Analytics application and customer AMI data. Work has commenced to address issues as detailed in section 4.5.5.3 Pole Type Transformer Forecast Replacement Volumes.

QOS non compliances are identified reactively through customer initiated enquires and since 2018 proactively through the JEN Analytics application via the AMI (Advanced Metering Infrastructure) 5-minute voltage monitoring data.

Power quality customer enquiries are investigated to determine if the issues are customer initiated or network related. The number and type of verified issues are tabulated below.

Table 4-39: Verified QOS Issues (RIN 3.6)

Performance Indicator	2013	2014	2015	2016	2017	2018	2019	2020	FY 20/21	FY 21/22
Low voltage supply	30	29	23	29	20	30	13	10	5	15
Voltage dips	9	10	6	18	15	20	12	8	6	0
Voltage swell	1	1	0	2	0	5	23	37	39	0
Voltage spike (impulsive transient)	1	1	1	1	0	2	10	1	1	0
Waveform distortion	0	0	0	0	0	1	1	0	0	0
TV or radio interference	-	-	-	-	-	-	0	0	0	0
Solar related*	-	-	19	28	73	89	161	125	118	70
Noise from appliances	-	-	-	-	-	-	0	1	1	0
Other	125	102	61	48	47	27	19	98	56	30

*Solar Related performance indicators began in 2015.

Proactive transformer quality and reliability performance assessments are facilitated by the JEN Analytics application based on 5-minute AMI meter data. Transformer voltage profiles can be traced over extended time periods and adjustments instigated to resolve non-compliances. Abnormalities in voltage levels are used to identify developing faults at both the substation and LV distribution network level.

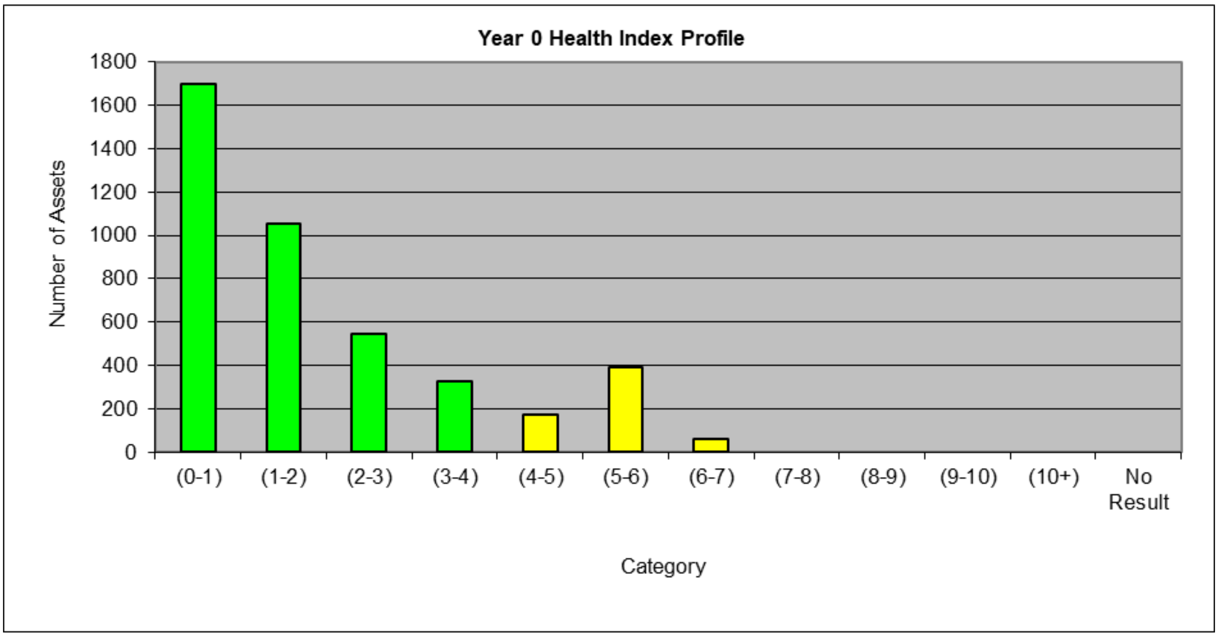
Transformers proactively or reactively identified as having supply quality issues or excessive overload are being addressed as part of the Distribution Substation Augmentation program. These substations and their associated LV components are upgraded or reconfigured to resolve the supply issues.

JEN's ESMS specifies the minimum mounting heights for pole type transformers. Due to changes in construction standards and historically different construction practices a significant number of pole type substations did not comply with the current minimum height requirements. A program was developed to identify, prioritise and rectify these non-compliances and this work has been completed. Any pole type substation that is now found to be non-compliant is dealt with as part of the normal asset replacement activity.

4.5.3.2.1 Condition Assessment – Pole Mount Transformers

Condition assessment of pole type transformers is conducted through inspections and audit programs such as the Line Inspection Program and thermal surveys. As a result of these programs plant maintenance notifications are raised for the rectification of defects or replacement of assets as required.

Figure 4-40: Year 0 (2024) Health Index



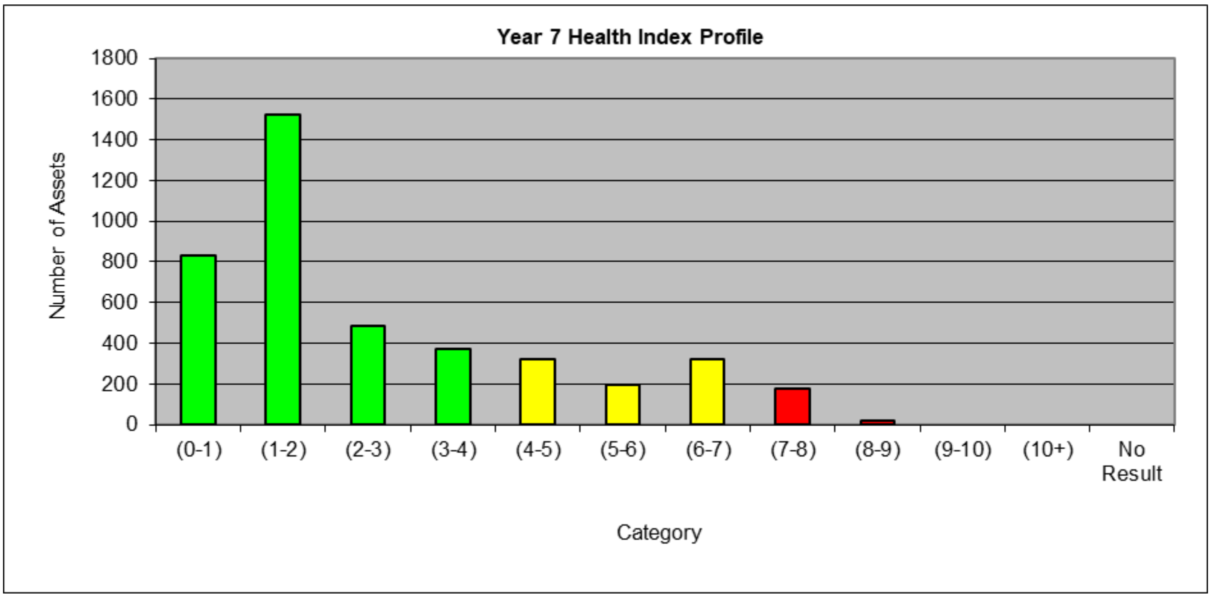
The overall condition of the pole type transformer family has been assessed using the CBRM methodology. Figure 4-40 shows the current Year 0 (2024) health index for the population of pole type transformers.

Total risk for all failure scenarios at Year 0 is calculated to be $318k with a current failure rate of 19 per annum. These failures can range from a minor failure where maintenance work is required such as an oil leak, to a major failure that includes replacement of the unit.

If replacement is deferred until Year 7 (2031) the health index changes as indicated in Figure 4-41.

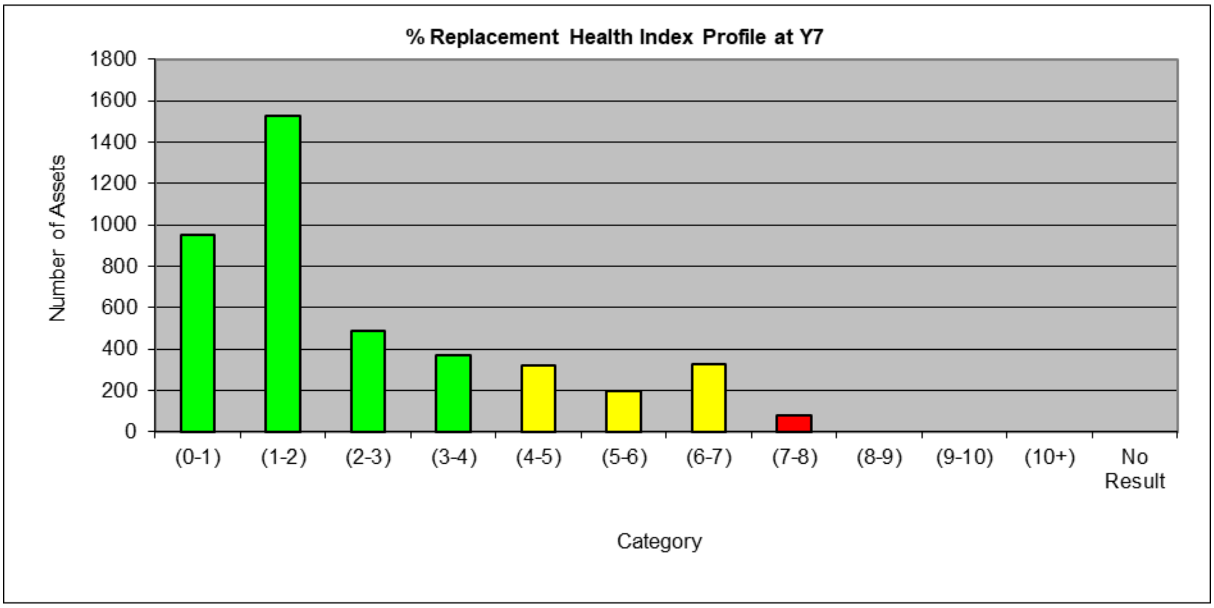
Total risk for all failure scenarios at Year 7 is calculated to be $410k with a predicted failure rate of 25 transformers per annum.

Figure 4-41: Year 7 (2031) Health Index Profile



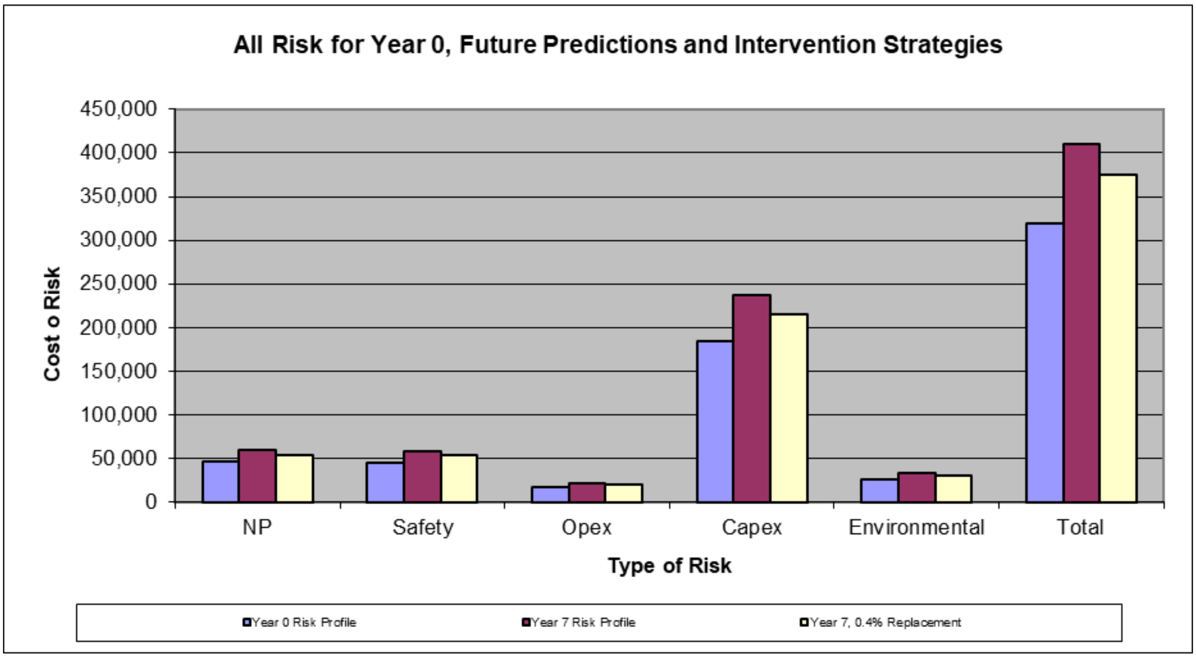
If a 0.4% per annum replacement rate is applied (17 replacements per year) then the health index profile changes as indicated in Figure 4-42.

Figure 4-42 - 0.4% Replacement rate Year 7 Health Index Profile



These results indicate that the majority of distribution pole type transformers are well below their expected life of 50 years and are in good condition. Furthermore, the cost of risk to the network should they fail is highly influenced by the cost of replacement (CAPEX) as indicated in Figure 4-43.

Figure 4-43: Risk Profile for Year 0 (2024), Year 7 (2031) and with a 0.4% replacement rate, Pole Mounted Transformers



The CBRM model forecasts a failure rate of between 19 and 25 transformers per annum over the next 7 year period. These failures are the sum of failures classified as minor, significant and major failures. This is consistent with the recent failure rates for these types of assets. In order to maintain the assessed risk and the health index profile associated with the operation of these assets at current (year 0) levels this strategy proposes the replacement of approximately 20 transformers per annum over the next 7 year period. Pole type transformers identified as being in poor condition at Year 7 will be prioritised for replacement.

4.5.3.2.2 Condition Assessment – Voltage regulators

The two line voltage regulator installations on JEN were installed in 1997 (SBY24) and 2007 (COO11) which makes them both less than 25 years old. There are no known asset condition issues and a spare unit is held in stock to facilitate any maintenance or replacement requirement.

4.5.4 RISK

4.5.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. An asset criticality assessment was conducted at sub-asset class level in accordance with the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is also used to rank the importance of dissimilar sub-asset classes (e.g., transformer platforms) to identify areas where risk should be managed first, and control measures implemented.

The Pole type transformer asset class has an asset criticality score of AC2 (Moderate) due to the consequence of a pole type transformer failure having the potential to cause third party damage and injury to JEN personnel and members of the public.

Pole type distribution substations influence JEN's overall network performance in terms of reliability and quality of customer supply. The JEN is configured such that in the majority of cases the impact of customer outages associated with a substation can be minimised through HV switching and LV parallels so that supply to customers can be restored promptly.

4.5.4.2 *Failure Modes*

Failure modes for this sub class include:

- Thermal failure - due to overload, out-of-balance load, and deteriorated or high resistance connections;
- Insulation failure - due to loss of insulation medium (oil leak), heat and age related winding insulation deterioration, lightning strikes, high voltage injections, switching events, or water penetration;
- Winding failure – winding distortion due to a through-fault;
- Deterioration or corrosion – age and environmental related deterioration of seals, paint, insulation, connections; and
- Failure due to external factors – such as vehicle strikes, animals, vandalism and weather.

The possible consequences of the above failures includes:

- Operation of protective devices including blown fuses and circuit breaker trips;
- Excessive heat, hot spots and annealing;
- Molten material and possible fire;
- Internal or external flashover between HV to LV, HV to earth, LV to earth and inter-turn;
- Oil spill and possible environmental impacts; and
- Distortion of tank, winding, lead supports.

4.5.4.3 *Current Risks*

The risks associated with the pole type transformer failures are described in Section 4.5.4.2. For details of the risk assessment, refer to JEN's Compliance and Risk System (OMNIA).

Apart from transformer failures, poor performance has credible regulatory compliance risks.

Pole type transformer performance is directly related to customer energy consumption. The ability to deliver the required level of supply quality and reliability is compromised when either a customer's load or export energy levels exceed the transformer rating.

The uptake of solar generation by customers is rapidly increasing the level of energy being exported into the distribution network. As it grows in capacity it is creating conditions which have never been experienced or planned for when designing the network. The main impact is on the level of voltage being supplied to customers. To export energy, Embedded Generation (EG) systems require the voltage output of the EG to be higher than the network voltage at the customer's Point of Supply (POS). This facilitates the export of energy back into the distribution network. A cumulative voltage rise is further generated as more EG systems are connected to the low voltage network. Where voltage loss occurs as a result of load there is now a voltage rise due to the reverse current flows generated into the network. The supply voltage experienced by the customer can rise above the VEDC requirements at the customer's Point of Common Coupling (POCC). At a localised level the excessive voltage causes inverters to shut down and/or adversely affect QOS limits at both the customer's premise and neighbouring properties. At the network level the cumulative export capacity can potentially exceed the rating of the transformer and its associated components leading to possible asset failure.

Energy export doesn't always align with energy usage patterns. At the domestic level, peak energy demand typically occurs in the evening, whereas solar systems predominantly export energy during daylight hours when the sun is shining. Consequently, distribution substations must be equipped to handle the peak energy demands of customers in the evening, independent of embedded generation, while also maintaining acceptable voltage levels during the day when embedded generation is at its peak. Meeting the demands for supply quality in these fluctuating operating conditions poses challenges with the current static network infrastructure.

In addition, there is an increase in the amount of non-linear, “dirty” load and generation from customers’ equipment. This affects the ability of distribution substations to deliver a clean, distortion free supply. Non-linear loads, such as DC to AC power converters, switch-mode power supplies, dimmable switches, DC chargers (Electric Cars) and arc furnaces produce harmonics which inherently distort supply voltages creating a dirty supply. The cumulative impact of these dirty loads increases the base levels of harmonic distortion which increase the impact of individual localised harmonic distortion. Experience indicates that localised harmonic distortions can exceed the 5% supply voltage VEDC distortion limit.

4.5.4.4 *Existing Controls*

New transformer designs undergo an initial type test by the manufacturers to ensure they comply with the requirements of the product specifications.

Transformers installed in the field are constructed to the standard design requirements and the final construction is audited to ensure compliance. The design and construction standards incorporate the following controls to mitigate against failure events.

- Substation and Plant construction standards (Distribution Construction Manual, Volume 2, Section 3.0) – reduce the likelihood of poor construction practices, and the use of non-standard construction methods;
- Clearances, Design & Construction Principles (Distribution Construction Manual, Volume 1, Section 2.6) - prevent points of contact between network elements;
- Surge Arrester Procedure (JEN PR 0011) – sets out the requirements for overvoltage protection of high cost equipment to protect against events such as lightning strikes;
- Animal and Bird Protection Procedure (JEN PR 0065) – Sets out the requirements for the installation of added covers to prevent animal contact between live and earthed components.

Other operational controls include:

- Standard Asset Inspection Program – 3 to 4 yearly visual inspections to ensure asset integrity;
- Thermographic surveys – on a 1 to 3 year cycle. Pole type transformers along the backbone of the feeder are surveyed to identify hot spots caused by overload and high impedance connections;
- Maintenance process - Plant maintenance notifications are raised and prioritised for the rectification of defects or replacement of assets when identified;
- Pole type transformer load monitoring – cumulative customer energy load profiling relative to transformer nameplate rating; and
- Quality of supply monitoring – 5 minute spot voltages, voltage variations and outages are monitored via JENA based on AMI (Smart) meter data.

As part of the criticality assessment; consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015).

4.5.4.5 *Future Risks*

Changes in load profiles due to both changing usage patterns and embedded generation are occurring, and the outcomes of these changes are currently being assessed and modelled. The initial indicators are that there will be an overall increase in the demand for energy and that the increase will need to be diversified to avoid excessive increases in maximum demands. The most significant impacts will come from Electric Vehicle (EV) charging and electrification.

As Victoria is moving towards a lower carbon footprint there will be a push towards EV's away from the traditional fossil fuelled vehicles. The energy demands for EV's will have to be met by the current electricity infrastructure in conjunction with non-network generation. Their demands will add to the daily load profiles and if they follow a similar pattern will increase usage in peak demand periods. Usage will therefore need to be managed to limit their impact on network maximum demands.

Off peak and peak usage, will have an impact on the cyclic rating of transformers. Off peak usage will result in load being diversified across a 24 hour period thus reducing the transformer cooling time and as a result, require a reduction in the cyclic ratings to manage the transformers performance. An increase in peak usage will require more capacity to be added to the network increasing the network cyclic rating. Further studies are required to identify the impact that the new energy profiles will have on the cyclic rating of transformers.

However these risks are managed through the Consumer Energy Resources Integration Strategy.

4.5.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy covers time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance.

4.5.5.1 *Creation*

New pole top transformers (pole type substations) are deployed on the JEN in response to the following primary drivers:

- New network load via the Customer Initiated Construction process;
- The Distribution Substation Augmentation Program in response to organic load growth in established parts of the distribution network; and
- The Distribution Substation Augmentation Program in response to supply quality non compliances.

The need for new distribution substations is identified to meet customer load requests via the CIC processes or via the JEN Analytics application. New substations are planned after reviewing and confirming substation loading data and the results of supply quality investigations. This then drives the Distribution Substation Augmentation Program.

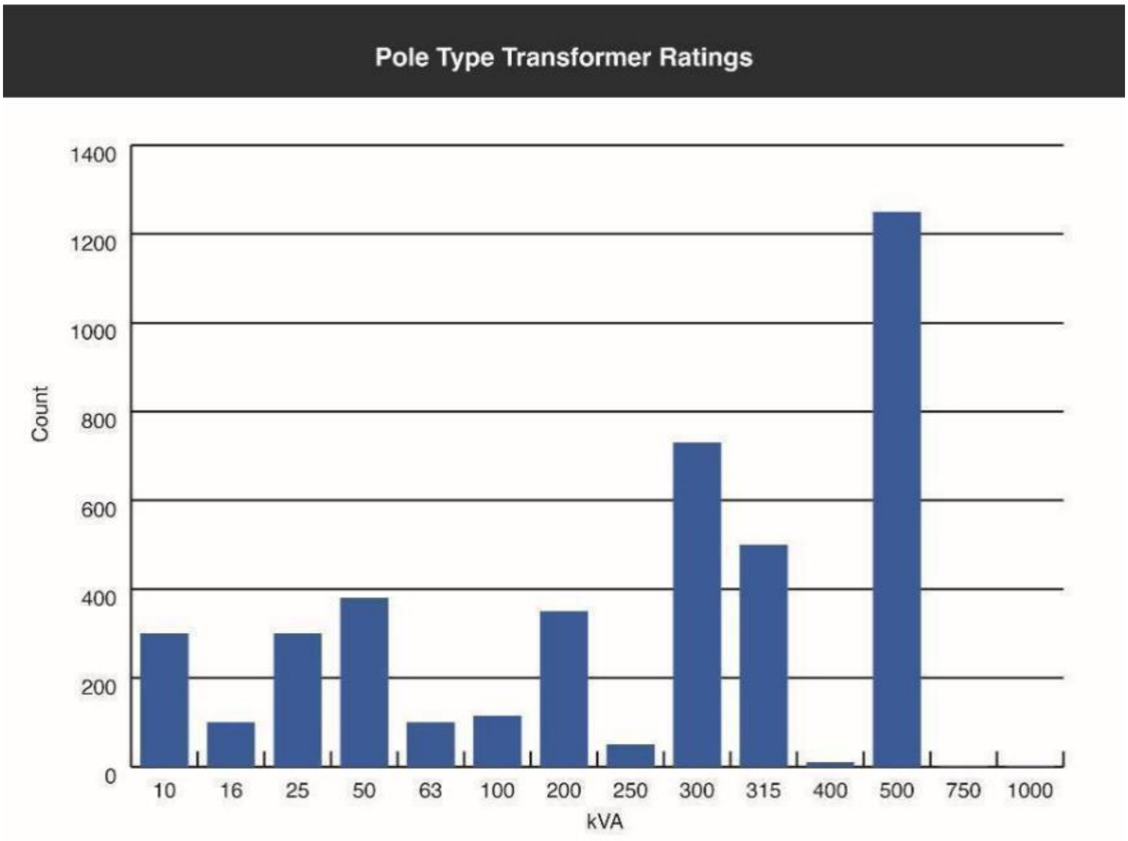
JEN has standardised the range and capacity of pole type transformers for use on the network as indicated in Table 4-40. Other sizes and capacities have been used historically but as these reach end of life or are upgraded they are replaced with a standard size pole type transformer.

Table 4-40: Standard Pole Type Transformers

Primary Voltage	Capacity (kVA)							
	Single Phase			Three Phase				
22kV	16	25	50	25	63	100	315	500
11kV	16	-	-	-	-	-	315	500
6.6/11kV	-	-	-	-	-	-	315	500

The population of pole type transformers installed on the JEN and characterised by their kVA rating is indicated in Figure 4-44.

Figure 4-44: Pole Type Transformer Population by Rating



4.5.5.2 *Asset Operation and Maintenance*

There are three (3) considered life cycle management options for pole type transformers and pole mounted voltage regulators:

- Asset Inspection and Condition Monitoring;
- Preventative Maintenance; and
- Reactive and Corrective Maintenance.

4.5.5.2.1 Asset Inspection and Condition Monitoring

The inspection of transformers is carried out as part of the Line Inspection program. All assets in the HBRA are inspected every 3 years and in the LBRA every 4 years. A thermal survey of transformers and connections is also performed to assist in the detection of potential failures before they occur and are aligned with the regular overhead line thermal survey cycle which occurs every 1, 2, or 3 years depending on asset criticality.

Inspection activities include checks for general cleanliness, oil level, signs of oil leaks, corrosion of tank/cooler/conservator, tank distortion, broken porcelain, tracking on bushings and surge arresters if fitted on transformers, bushing leads and animal shields are secured, droppers are free from vegetation interference, and clearances between live conductors are maintained.

For details of the activities involved in the inspection program, refer to the JEN MA 0500 - Asset Inspection Manual.

In addition to the above, pole mounted voltage regulators have their tap changer operation counts read and recorded in SAP every three months to provide the trigger for routine condition based preventative maintenance of the tap changers.

4.5.5.2.2 Preventative Maintenance

4.5.5.2.2.1 Proactive Replacement

Proactive replacement is driven by the monitoring of pole type transformer loads and the results of supply quality investigations. The Distribution Substation Augmentation Program drives the replacement as well as the creation of pole type transformers. For details of the program and the criteria used to assess and prioritise replacements refer to the Distribution Substation Augmentation, Network Development Strategy ELE PL 0017. Proactive replacement of pole type distribution substations will typically occur as a result of load growth or customer requests for increased supply. The replacement normally also involves an upgrade in capacity if possible. Given that the capacity of the largest pole type transformer is limited to 500kVA. The pole type transformers that are taken out of service as part of the replacement process are then assessed and refurbished where possible in accordance with the Distribution Transformer Refurbishment Procedure (ELE AM PR 0047).

On the JEN small single phase 10kVA pole type transformers are a family of transformers that have been identified as being most at risk of overload. Customer loads and export energy demands can easily exceed their limited capacity. The 10kVA’s are the smallest transformer currently in service and are commonly installed in the HBRA where they can supply up to 4 customers in isolation from alternative sources of LV supply. The transformers themselves are configured with two LV windings each rated at 5kVA, the LV windings can be connected in parallel or series. When in parallel the two LV windings form a single phase 240/250 Volts supply and are rated at 42/40A. When in series they form two single phase 240/250 Volts supplies rated at 21/20A each or 240-480/250-500 Volts supplies rated at 21/20A. Care needs to be taken when connecting load to these transformers as they can be easily overloaded particularly if large PV installations are involved.

These 10kVA transformers are an older style of transformer with 75% of the units currently in service over 30 years old. The historical failure rates of these 10kVA transformers are not reflective of their overload status or age profile. Even though historically these 10kVA transformers have not had high failure rates the risk and associated potential consequence of any future failures in the HBRA is significant. A targeted program has been established to identify and replace overloaded 10kVA transformers in the HBRA.

4.5.5.2.2.2 Condition Based Replacement

The condition of pole top transformers is monitored via the Pole and Line Inspection program and the Thermal Survey program. In addition, the operating environment as defined by transformer loads, is monitored via the Business Objects reporting tool and the JEN Analytics Application which uses connectivity data from GIS and AMI energy data to measure and report on the load profiles for the various elements of the distribution system.

The results of this condition monitoring activity is used to drive the condition based replacement of pole type transformers when they are found to be in poor condition. Poor condition is defined by a range of conditions including the effects of corrosion and oil leaks.

4.5.5.2.2.3 Voltage Regulator Tap Changer Maintenance

The preventative maintenance of the on load tap changers in the pole mounted line voltage regulators is triggered by the operations counters or cyclometers that are part of the regulator control system. These cyclometers are read every three months and maintenance is scheduled after 100,000 operations. Currently the SBY24 regulator requires maintenance about every 5 to 6 years (50 operations per day). The COO11 regulators are only performing about 15 operations per day. A spare unit is retained so rather than maintain the regulators on site they are changed out and maintained by the manufacturer of site. The control settings on the voltage regulators have a significant impact on the number of tap changer operations performed per day and thus the maintenance requirements. These settings require periodic review to balance the supply quality outcomes against the maintenance needs.

4.5.5.2.3 Reactive And Corrective Maintenance

Reactive and corrective maintenance is carried out when faults occur or after asset inspection programs identify any urgent maintenance, for example, in service electrical faults or excessive oil leaks.

Undersized Neutrals, refer to section 1.3.5.3

4.5.5.3 *Pole Type Transformer Forecast Replacement Volumes*

A program has been developed to target for replacement pole top transformers that are overloaded at levels greater than 150% of their nameplate rating. In particular those located within the HBRA will be prioritised.

In addition to the replacements proposed for the overloaded family of pole type transformers a number of projects have been identified that are required to ensure that network performance is maintained at current levels and our compliance requirements are addressed.

Table 4-41 lists the forecast replacement volumes for pole type transformers from 2025 to 2031 required to maintain the performance of the asset class.

Table 4-41 Forecast Replacement Volumes – Pole Type Transformers

Unique ID	Service Code	Pole Type Transformers	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A140	RHA	Transformer Pole Mounted	28	32	32	32	32	32	32

4.5.5.4 *Asset Disposal*

All pole type transformers that are taken out of service for any reason are returned to the store for assessment and where possible refurbishment (Distribution Transformer Refurbishment Procedure - ELE AM PR 0047). Transformers that are considered unsuitable for refurbishment for any reason are scrapped.

The transformer is taken out of service, returned to the depot and stored in a bunded area. The transformer oil is tested for PCB content and disposed of appropriately under a contract arrangement.

Disposal of all materials shall be in accordance with JEM PO 1600 – Scrap Material Policy.

4.5.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment.

4.5.5.6 *Spares*

The replacement of pole type transformers is largely driven by the need to upgrade transformers to meet increasing capacity requirements. This significantly impacts on the number of transformers that would otherwise be replaced because they had reached the end of life.

When transformers are removed from service for reasons other than defect repair, such as load growth, load decrease, noise, redundancy or maintenance, they are assessed using the criteria set out in the Distribution Transformer Refurbishment Procedure – ELE AM PR 0047. Transformers that satisfy the criteria shall be refurbished and returned to stock for future use. Those that do not meet the criteria shall be scrapped.

The replaced transformer will be assessed according to the below criteria to determine if the transformer should be refurbished and returned to service or be scrapped:

- PCB Contamination;
- Voltage ratio and tapping range*;
- Conditions including, internal faults, brown porcelain bushings, rust, impacts, distortion, confirmed noise complaints;
- Age and capacity;
- Configuration, size and weight; and
- Cost of refurbishment.

Refurbishment shall only be carried out if the transformer satisfies the criteria as described in the Distribution Transformer Refurbishment Procedure – ELE AM PR 0047.

*The typical tapping range for old transformers is between 100% and 90% for 415/240V transformers and 102.5 to 92.5% for 433/250V transformers, these ranges fall outside of the retention range of 105-95% as detailed in ELE AM PR 0047 – Distribution Transformer Refurbishment Procedure. In general, transformer tapping ranges are not clearly defined in existing records. An emphasis will be placed on identifying and documenting the tapping range and set tap position while conducting upcoming Inspection Programs.

Emergency pole type transformer stock is determined based on the quantity of the items in service on the network and its historical usage. Typical emergency stock levels are shown in Table 4-42.

Table 4-42: Pole Type Transformers Emergency Stock Levels

Voltage	Phases	Capacity	Minimum Stock	Maximum Stock
22kV	1	16kVA	0	0
22kV	1	50kVA	7	7
22kV	3	25kVA	0	0
22kV	3	63kVA	4	4
22kV	3	100kVA	1	1

Voltage	Phases	Capacity	Minimum Stock	Maximum Stock
22kV	3	315kVA	7	7
22kV	3	500kVA	8	8
11kV	3	315kVA	2	2
11kV	3	500kVA	1	1
11/6.6kV	3	315kVA	2	2
11/6.6kV	3	500kVA	1	1

4.5.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides context for and determine the information required to manage and operate an Asset Class.

The information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

From these business objectives, it is possible to identify at a high-level the content of the business information systems' required to support these objectives (Table 4-43).

Table 4-43: Pole Transformer Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

	• Energy consumption	

Table 4-44 below identifies the current and future information requirements to support the Asset Class's critical decisions and their value to the Asset Class.

Table 4-44: Pole Transformer Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Pole transformers acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied pole type transformers and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Sub Name - Type - Operating level - Feeder - Circuits - Date Installed - Live Line Clamp - CMEN - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Utilisation • Load balance on each circuit by phase • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-45 provides the information initiatives required to provide the future information requirements identified in Table 4-44. Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-45: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improve/review MAT Code definitions	Ability to align to AER service classification structure.	High	Precise definition
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.6 NON-POLE TYPE DISTRIBUTION SUBSTATIONS SUB-ASSET CLASS

4.6.1 INTRODUCTION

Non-Pole Type Distribution Substations as a group includes the following types of distribution substations:

- Indoor substations – These are substations installed within a building, either in a free standing structure or in one or more rooms incorporated in a larger building. They may be at ground level or accessed via a basement and are generally installed to service the electrical load associated with the larger building in which they are installed. They are comprised of individual components assembled and installed in the substation room. They may also be utilised to service other electrical load via LV street distribution cables.
- Kiosk or padmount substations – These are self-contained prefabricated substations housed in a weatherproof metal enclosure and installed on a preprepared foundation or slab. They contain HV switchgear, a transformer and LV switchgear. They are installed in reserves and easements on private property to service dedicated customer loads and LV street distribution cables.
- Ground type substations – These are substations installed in fenced compounds and fed at HV by overhead conductors. They are used on the overhead network where the required load exceeds the capacity of a pole mounted substation (500kVA). They are comprised of one or more ground mounted transformers, a pole supporting the HV switchgear and fusing and some form of outdoor LV bus and switchgear. They are used normally to service the load associated with an industrial customer. This type of substation design is obsolete and no longer approved on the JEN.
- Underground substations – These types of substations are installed in underground vaults normally accessed via dedicated stairwells or hatch overs and ladders. They may be classified as confined spaces. The installation of HV switchgear and LV switchgear is the same as for indoor substations. This type of substation design is obsolete and no longer approved on the JEN.
- Cubicle substations – These types of substations are comprised of individual interconnected cubicles mounted side by side. Each cubicle contains the different components of a substation. That is a HV cubicle containing the incoming cables and HV switchgear, a transformer cubicle and a LV cubicle containing the LV cables and switchgear. This type of substation design is obsolete and no longer approved on the JEN.
- HV metering cubicles – These cubicles are weatherproof prefabricated metal enclosures containing the HV current transformers and voltage transformers required to provide the energy metering requirements of HV customers; and
- Switching cubicles – These are self-contained prefabricated weatherproof enclosures housing HV ring main type switchgear. They are used to facilitate the operation of the HV underground distribution network.

These substations and their associated circuits and ancillary equipment are the networks interface with domestic, commercial and industrial customers and facilitate their energy supply and export requirements.

To ensure this asset class successfully delivers these values requires distinct performance measures, risk analysis, condition based monitoring, inspection programs and customer interaction, all of which are described in this sub-asset class document.

The key performance measure for non-pole type distributions substations is its capacity to interface with the various types of equipment customers connect to the network. An appropriately rated transformer along with an electrically strong network will deliver a quality electricity supply that meets customer demands reliably and safely.

These substations are made up of one or more of the following components:

- the structure or enclosure;
- transformer/s;
- HV switchgear;
- LV switchgear;
- protective devices, HV and LV; and
- metering and wiring attached.

Substations that supply LV customers convert High Voltage (HV) at either 22kV, 11kV or 6.6kV to a nominal supply voltage of 400/230V. Supply is provided either directly to customers via dedicated consumers mains cables or via the low voltage distribution network. Substations can be comprised of one or multiple transformers to supply individual customer supplies. Transformers are selected based on the HV distribution voltage, the type of customer and the size of load it will supply. The capacity or rating of the transformer is expressed in kVA. The capacity of JEN's non-pole type substations varies from 50kVA up to 8,000kVA.

HV metering structures are installed in HV customer installations who manage their own electrical network beyond the metering structure.

HV switching stations are used to provide operational flexibility and control of the HV underground network.

JEN operates 2,681 non-pole type distribution substations and the number of customers supplied by each of these substations ranges between 1 and 322 customers. There are HV switching devices contained within these substations. They include SF6, oil and air insulated switching devices with various current making and interrupting capabilities.

4.6.2 ASSET PROFILE

4.6.2.1 *Life Expectancy*

As prescribed in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for non-pole type distribution substation assets is as follows:

- kiosk/pad mount substations 40 years;
- ground/indoor substations 50 years; and
- distribution switchgear 40 years

The above procedure considers asset lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has undertaken a number of reviews of asset useful lives with consulting agencies and held discussions with other Distribution Businesses to ensure assigned asset lives are realistic.

4.6.2.2 *Age Profile*

The population of non-pole type distribution substations can be characterised as follows:

- 162 ground type substations;
- 498 indoor substations;

- 5 underground substations;
- 104 HV metering cubicles;
- 5 cubicle type substations; and
- 1,907 kiosk substations.

The population of distribution switchgear can be characterised as follows:

- 1,925 Ring Main Units; and
- 235 indoor air break switches.
- 24 HV Disconnectors.
- 19 Gas switches
- 416 Circuit Breakers

Of the 1,925 Ring Main Units, 1,100 units are of an oil immersed rotary switch type which is incorporated in the current Wilson Transformer kiosks.

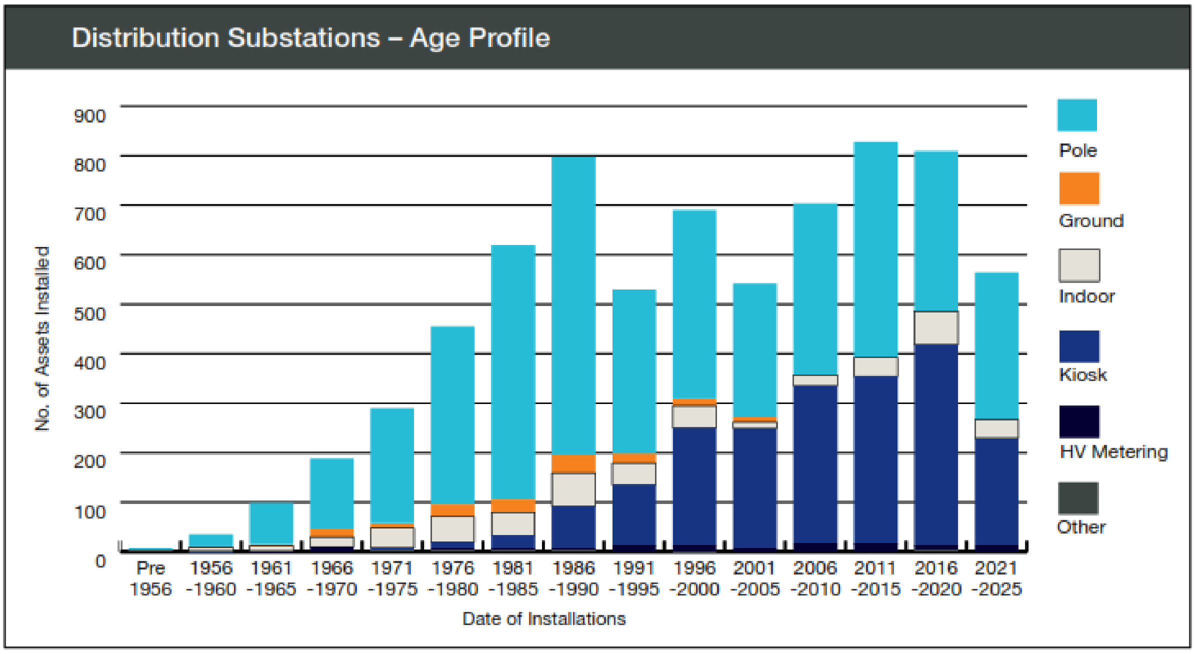
The age profile for non-pole distribution substations is presented two ways as follows:

- By site, the date when the substation site was first established; and
- By Transformer age.

The substation site date remains constant whereas the transformer date is updated when the transformer is upgraded or replaced**.**

Figure 4-45 includes all substation types installed on the JEN. The chart indicates that the installation of new non-pole type substations has consistently increased and now exceeds the number of pole type substations installed year on year. This is reflective of the growth in the JEN underground distribution network.

Figure 4-45: All Substations by Type Age Profile



4.6.2.3 *Utilisation*

The operating capacity of a transformer is determined by its cyclic rating. Cyclic ratings are dependent on load types or load profiles and the transformers operating environment, consequently the loading of a transformer is assessed against its cyclic rating rather than its nameplate rating. Table 4-46 gives details of typical transformer cyclic ratings in non-pole substations. It should be noted that the rating of transformers located in enclosures is significantly impacted by this environment as cooling of the transformer is constrained by the enclosure.

Table 4-46: Cyclic Rating For Non-Pole Distribution Substations

Type	Nameplate (kVA)	Load Type	Summer Rating (kVA)	Winter Rating (kVA)
Indoor	315	Commercial	323	389
Indoor	500	Commercial	513	616
Indoor	750	Commercial	734	881
Indoor	1000	Commercial	979	1175
Indoor	1500	Commercial	1397	1680
Indoor	2000	Commercial	1862	2240
Ground	315	Commercial	337	403
Ground	500	Commercial	535	640
Ground	750	Commercial	767	913
Ground	1000	Commercial	1023	1218
Ground	1500	Commercial	1465	1736
Ground	2000	Commercial	1953	2315
Kiosk	315	Residential	339	420
Kiosk	500	Residential	539	666
Kiosk	500	Comm/Industrial	501	591
Kiosk	750	Comm/Industrial	719	848
Kiosk	1000	Comm/Industrial	959	1130
Kiosk	1500	Comm/Industrial	1439	1695
Kiosk	2000	Comm/Industrial	1918	2260

The rating table above is a guide only. For further details, refer to JEN Transformer Rating (Zone Substation and Distribution) plant guidance document. Consultation with the Customer and the Assets and Operations Engineering teams should be sought regarding rating matters.

The utilisation of distribution substations is reviewed via the Distribution Substation Augmentation Program. For details, refer to the Distribution Substation Augmentation, Network Development Strategy (Doc No. ELE PL 0017) and the Network Performance Plan 2021-2025 (Doc No. ELE-999-PA-IN-002).

4.6.3 PERFORMANCE

4.6.3.1 *Requirements*

The Electricity Safety (Management) Regulations 2019 require that JEN comply with its internal technical standards. JEN's internal standards reflect the requirements of the Electricity Safety

(Network Assets) Regulations 1999. JEN's network assets have been designed, constructed and are maintained in accordance with these regulations. In addition, JEN has conducted a Formal Safety Assessment as part of its Electricity Safety Management Scheme (ESMS). This included a risk assessment of the adequacy of JEN's current internal technical standards.

JEN uses internal construction standards when building non-pole substations. These are prescribed in the following standards:

- Distribution Construction Manual, Section 3.0 Substation and Plant construction; and
- Indoor Distribution Substation Procedural Standard – ELE AM PR 0048

These standards include design parameters which address areas including clearances, protection, equipment types, and ratings.

Each substation type shall be designed, manufactured and tested in accordance with the Standards listed in Table 4-47. These standards are called up and referenced in the "JEN Electricity Networks (Vic) Ltd 22kV, 11kV & 6.6-11kV, 16 kVA to 2000 kVA Distribution Transformer, Technical Specification".

These standards include design parameters such as voltage withstand, no load losses, thermal cyclic loading characteristics, and voltage tolerances.

Table 4-47: Relevant Australian Standards

Standard	Title
AS 1767	Insulating liquids - Specification for unused mineral insulating oils for transformers and switchgear
AS 2067	Substations and high voltage installations exceeding 1kV
AS 2374	Power transformers - Minimum Energy Performance Standard (MEPS) requirements for distribution transformers
AS 2629	Separable Insulated Connectors for Power Distribution System Above 1kV
AS 60076	Power transformers – General
As 62271	High voltage switchgear and control gear (series)
ENA DOC 007- 2006	Specification for Pole Mounting Distribution Transformers

The primary purpose of a substation is to provide a supply of electrical energy to the connected customers that complies with the Victorian Electricity Distribution Code of Practice (VEDCoP) with respect to Quality of Supply (QOS) and Reliability of Supply (ROS) requirements.

QOS and ROS issues are dynamic in nature, they develop as a result of the localised and cumulative effects of increasing demand and diversity that customers load and customers generation places on the LV networks. As customers electrical equipment is modernised; its impact and reliance on the networks compliance with the regulated QOS and ROS requirements increases. Reduced supply quality can have perceived and/or real impacts on the operation and lifecycle of connected electrical equipment. Substations play a vital role in maintaining a stable and reliable supply. The challenge for JEN is to remain compliant with the QOS and ROS parameters by efficiently matching the networks capacity to the varying requirements of its customer loads.

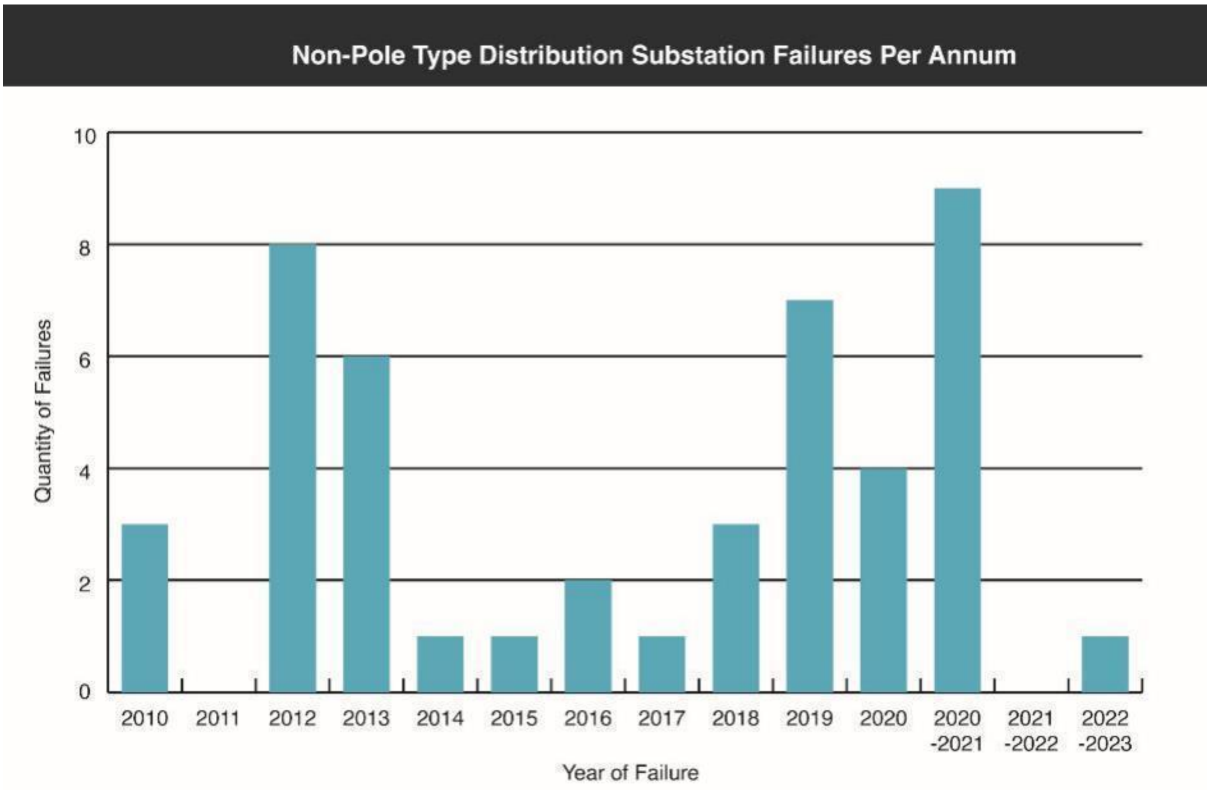
4.6.3.2 *Assessment*

The operational performance of the non-pole type substation population is assessed via the analysis of failure rates, quality of supply issues and load data.

Substation failures generally result in customer supply outages and can lead to public and operational risks, including oil spills and fire starts. Outages are captured via JEN's OMS where event details and disruption times are recorded. Failure modes and rates are monitored through SAP maintenance notifications to identify equipment reliability issues. The JEN Analytics application uses AMI data to monitor and report on the loading of all network elements from the substations down to individual customers.

Annual non-pole type distribution substation failure rates compiled between 2010 and 2022 indicate that on average approximately 4-5 substations fail catastrophically per annum, see Figure 4-46. In addition to these failures a number of substations or their major components will be replaced based on their condition.

Figure 4-46: Non-Pole Type Distribution Substation Failures



Condition monitoring of these substations is conducted as part of the Enclosed Distribution Substation Inspection Program (EDSIP) on a 3 and 4 yearly basis dependent upon their location (HBRA or LBRA). These inspections are carried out in accordance with the requirements of the "Enclosed Distribution Substation Inspection Manual - JEN MA 0695". Individual substations or particular classes of substation which are identified as having a current or emerging issue may be placed on a more frequent inspection cycle or included in a routine maintenance program designed to ensure the safety and operability of the substation is maintained.

To ensure the safety of network operators and maintenance staff, "Caution Regarding Operation (CRO)" tags are applied to switchgear identified as having operational issues or belonging to an asset class family which has a history of defect or failure. The CRO tag alerts all network staff to the fact that the switch requires particular work instructions or precautions related to its operation. The Network Control and Coordination Centre are able to identify and provide instruction to field staff regarding the specific requirements of a CRO tag applied to a particular network asset. A maintenance notification is then raised in SAP to address the identified CRO tag issue.

Since the creation of the Enclosed Distribution Substation Inspection Program in 2012, many maintenance notifications have been raised against non-pole substations with issues such as overgrown vegetation, subsidence of cable trenches, missing signs, graffiti, and access issues with only a small number of all notifications relating to electrical asset integrity issues such as low oil, low gas and missing or damaged insulation. The Enclosed Substation Inspection Notifications (ESIN) project was developed to address the issues identified by the inspection program.

The inspection program identified substations which may have asbestos related issues. As a result, a management plan has been developed that aims to monitor and or remove the asbestos and thus address the associated HSE risk level.

The capture of information on the type and setting of protective devices within these substations will be considered in the scope of future EDSIP's as there is limited information currently stored. Special consideration is to be given to fuse shunt trip type overcurrent protection systems employed in older indoor substations as there is limited information available in regard to this type of protective device. Most of these installations have been retired in conjunction with the 22kV conversion works in the Preston and East Preston areas however some remain in service in the FF supply area.

Quality of supply issues related to these types of substations generally occur as a result of overload. An overload occurs when there is an excess of customer load or reverse energy flow due to embedded generation relative to the substations rating.

Overloads are proactively assessed using the JEN Analytics application through customer energy usage data (AMI meters). The load profiles of non-pole type transformers are analysed Currently there are 76 substations with maximum demands exceeding 150% of the substations installed (nameplate) capacity. This far exceeds the cyclic rating of the installed transformers. The number of overloaded non-pole transformers and their sizes are indicated in Table 4-48.

Table 4-48: Maximum demands greater than 150% of rating (non-pole type)

Substation Rating (kVA)	Maximum Demands > 150 % of Rating
50	1
300	37
315	6
500	13
750	3
1,000	5
1,500	6
1,750	1
2,000	3
3,000	1
Grand Total	**76**

QOS non compliances are identified reactively through customer initiated enquires and since 2018 proactively through the JENA application. The number and type of verified issues are indicated in Table 4-49 below.

Table 4-49: Verified Quality Of Supply Issues (RIN A 3.6)

Performance Indicator	2013	2014	2015	2016	2017	2018	2019	2020	FY 20/21	FY 21/22
Low voltage supply	30	29	23	29	20	30	13	10	5	15
Voltage dips	9	10	6	18	15	20	12	8	6	0
Voltage swell	1	1	0	2	0	5	23	37	39	0
Voltage spike (impulsive transient)	1	1	1	1	0	2	10	1	1	0
Waveform distortion	0	0	0	0	0	1	1	0	0	0
TV or radio interference	-	-	-	-	-	-	0	0	0	0
Solar related[4]	-	-	19	28	73	89	161	125	118	70
Noise from appliances	-	-	-	-	-	-	0	1	1	0
Other	125	102	61	48	47	27	19	98	56	30

Proactive substation quality and reliability performance assessments are being facilitated by the JENA application based on AMI meter data. Substation voltage profiles can now be studied over extended time periods and adjustments instigated to resolve non-compliances. Abnormalities in voltage levels will be used to identify developing faults at both the substation and LV distribution network level.

Substations proactively or reactively identified as having supply quality issues or excessive overload are addressed as part of the Distribution Substation Augmentation program. As a result, substations and their associated LV components are upgraded or reconfigured to resolve these supply issues. This program prioritises substation augmentation to manage JEN's risk profile.

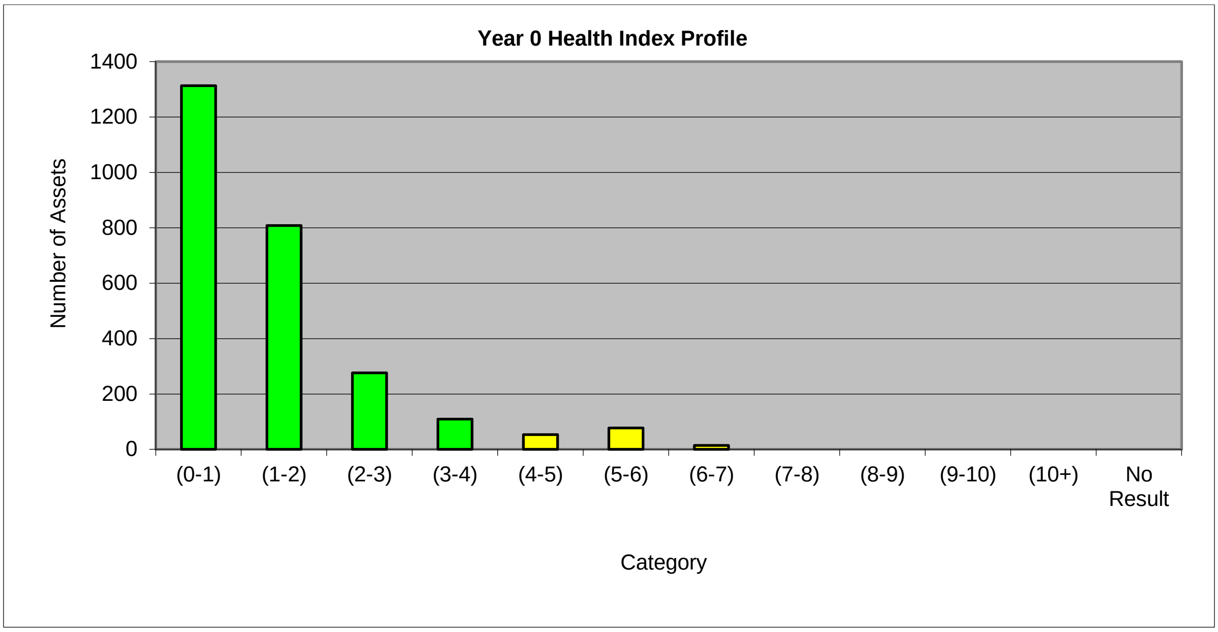
4.6.3.2.1 CBRM Assessment - Transformers

The overall condition of the non-pole type distribution transformer family has been assessed using the CBRM methodology. Initial CBRM modelling results for the current (Year 0) health index are shown in Figure 4-47.

Total risk for all failure scenarios at Year 0 is calculated to be $898k with a current failure rate of 21 per annum. These failures can range from a minor failure (maintenance work required) to a major failure that includes replacement of the unit (9 failures requiring replacement). It consists of impacts to network performance, safety of the public and staff, operational and capital expenditure to maintain/replace the unit and any associated environmental damage.

[4] Solar related performance indicators began in 2015.

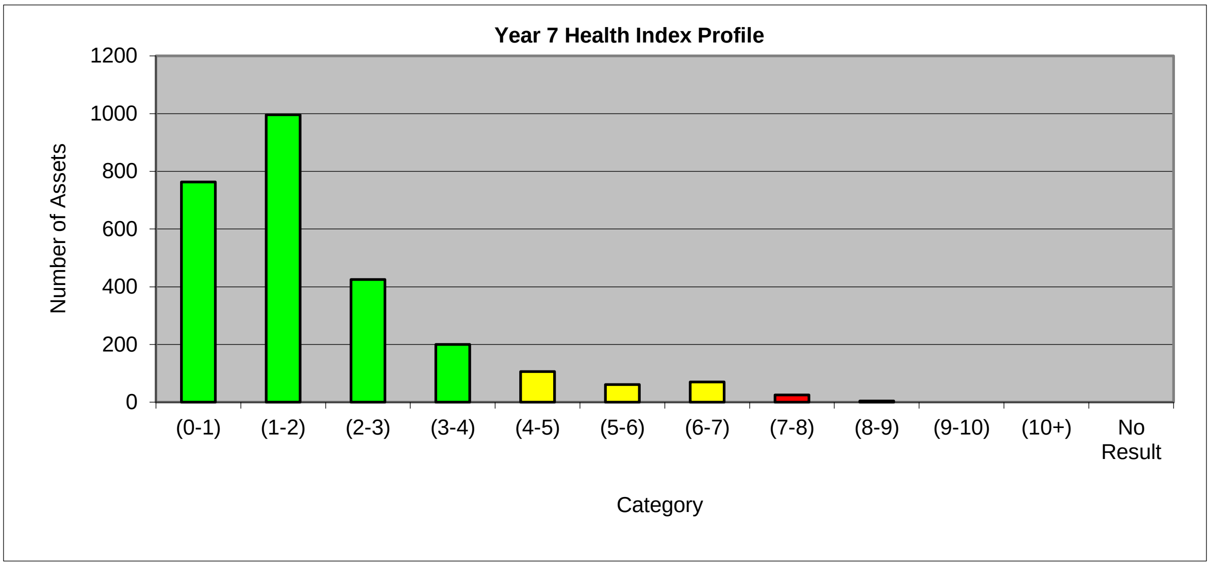
Figure 4-47: Non-pole type transformers Year 0 (2024) Health Index Profile



If replacement is deferred until 2031 (Year 7) the health index changes as shown in Figure 4-48.

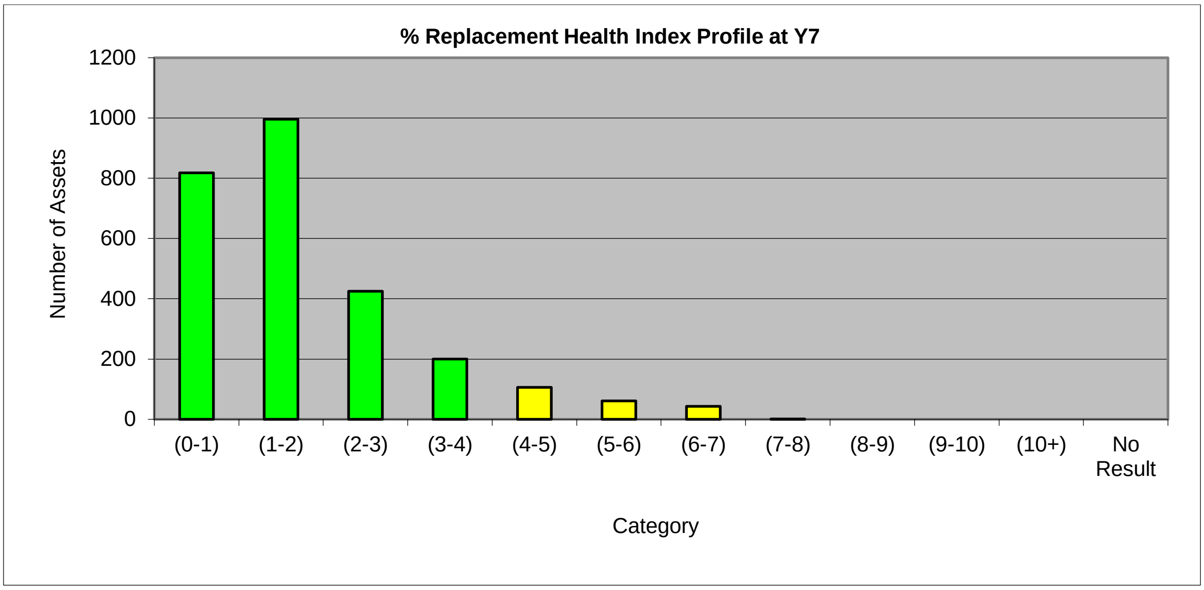
Total risk for all failure scenarios at Year 7 is calculated to be $969k with a predicted failure rate of 23 per annum (all failure types).

Figure 4-48: Non-pole type Transformers Year 7 (2031) Health Index Profile



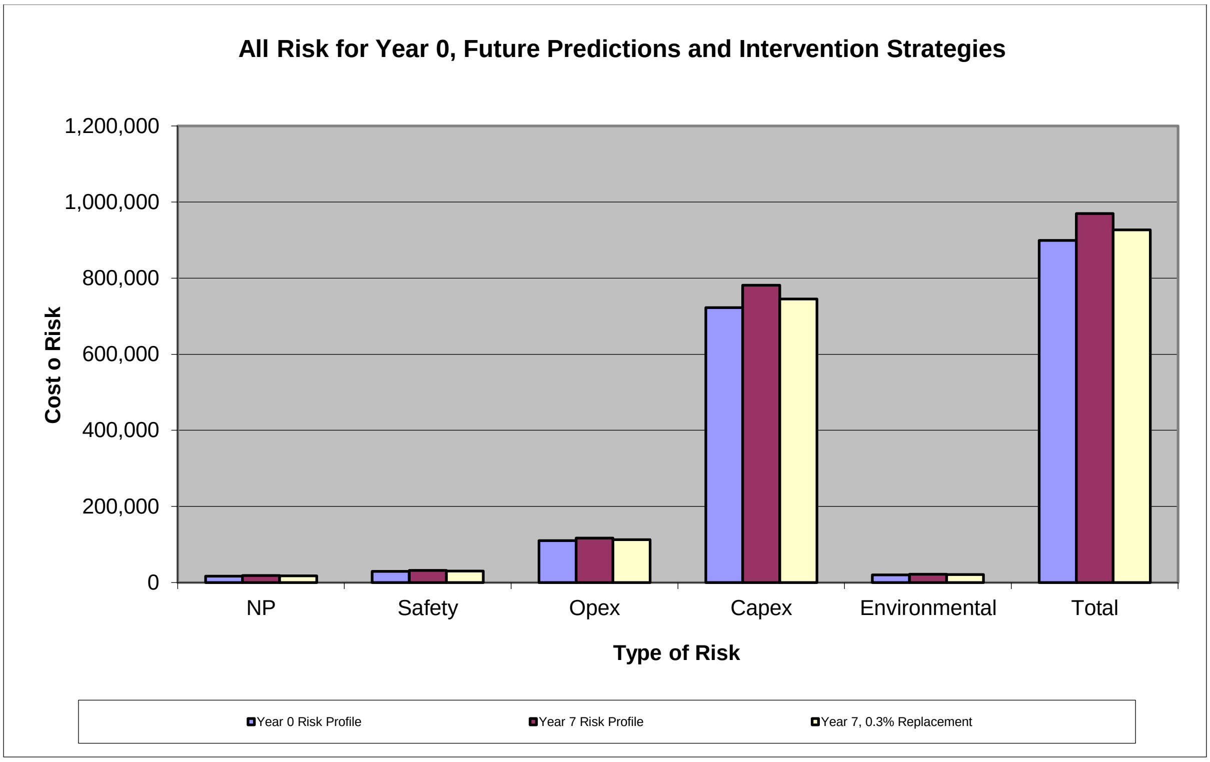
If a 0.3% per annum replacement rate is applied (8 replacements per year) then the health index profile changes as indicated in Figure 4-49.

Figure 4-49 0.3% Replacement Rate Year 7 Health Index Profile



These results indicate that the majority of the population of non-pole type distribution transformers are well below their expected life of 50 years. Furthermore, the risk should they fail is highly influenced by the cost of replacement (CAPEX) as indicated in Figure 4-50.

Figure 4-50: Non-pole type Transformers Risk Profile for Year 0 (2024) & Year 7 (2031)



The model forecasts the replacement or repair of approximately 22 transformers per annum over 7 years to maintain the risk at current (Year 0) levels. This forecast includes minor and major repair or replacement. In order to maintain the assessed risk and the health index profile associated with the operation of these assets at current (year 0) levels this strategy proposes the replacement of approximately 9 ground/indoor transformers per annum over the next 7 year period. This is consistent with current failure rates. Assets identified as being in poor condition at Year 7 will take priority when considering replacements.

4.6.3.2.2 CBRM Assessment – Ring Main Units

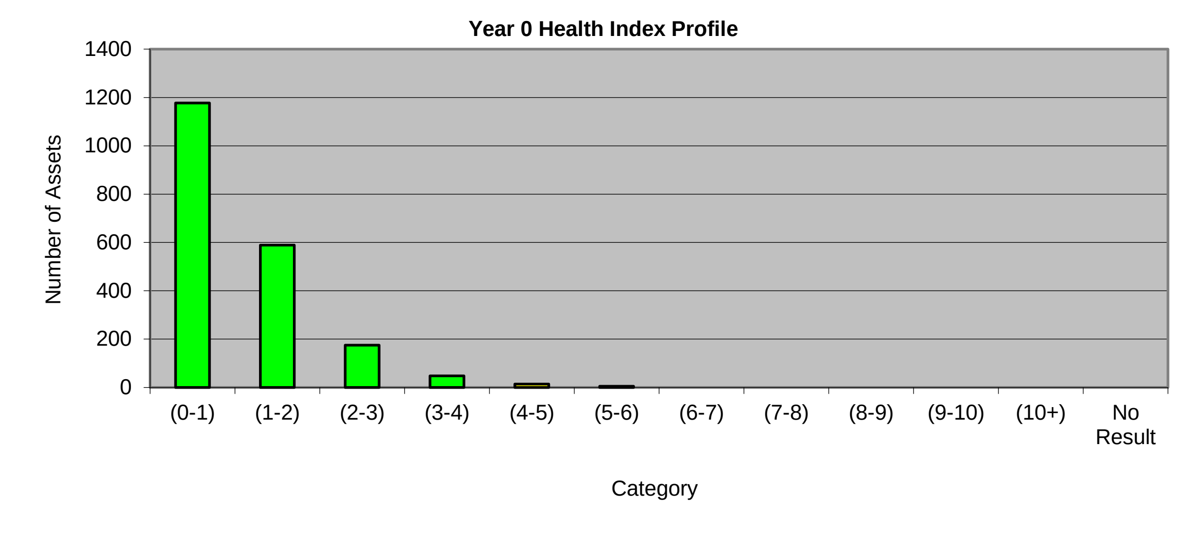
The overall condition of non-pole type distribution substation Ring Main Units (RMU's) has been assessed using the CBRM methodology. This assessment indicates that there are no systemic concerns in the medium term due primarily to the fact that these assets are generally aged well under their expected life.

Initial CBRM results indicated that the current (Year 0) health index is as shown in Figure 4-51.

Total risk for all failure scenarios at Year 0 is calculated to be $230k with a current failure rate of 3.4 per annum. These failures can range from a minor failure (maintenance work required) to a major failure that includes replacement of the unit. It consists of impacts to network performance, safety of the public and staff, operational and capital expenditure to maintain/replace the unit and any associated environmental damages.

These results indicate that majority population of Ring Main Units are well below their expected life of 40 years. Ring Main Unit failures affect the switching flexibility of the network, therefore their risk to the system if they do fail impacts primarily on network performance and the STPIS incentive.

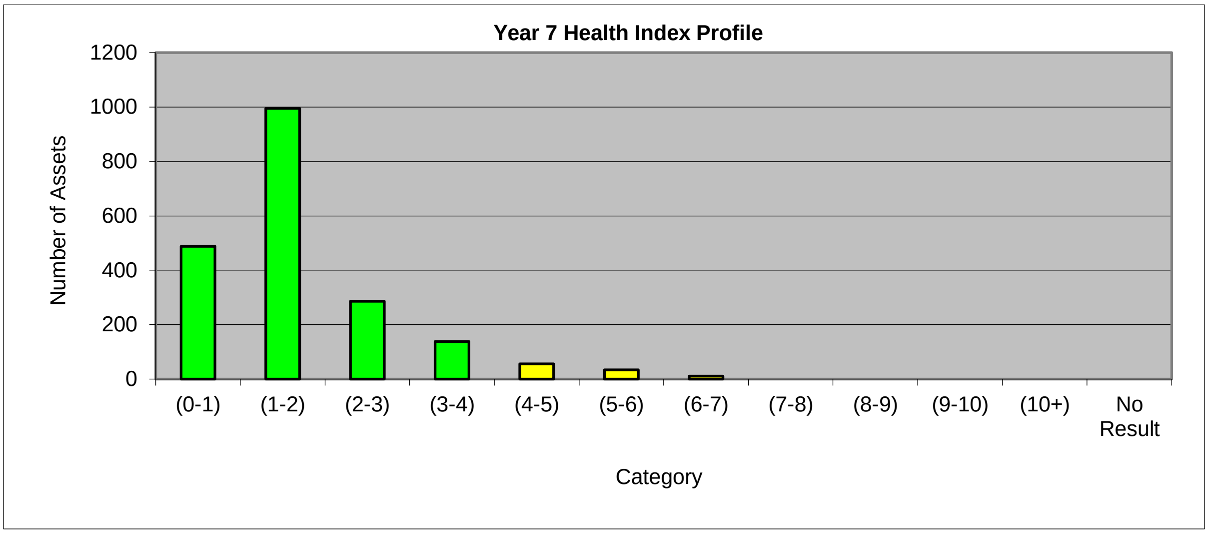
Figure 4-51: Year 0 (2024) Health Index Profile, RMU's



If replacement is deferred until 2031 (Year 7) the health index changes as shown in Figure 4-52.

Total risk for all failure scenarios at Year 7 is calculated to be $236k with a predicted failure rate of 3.6 per annum.

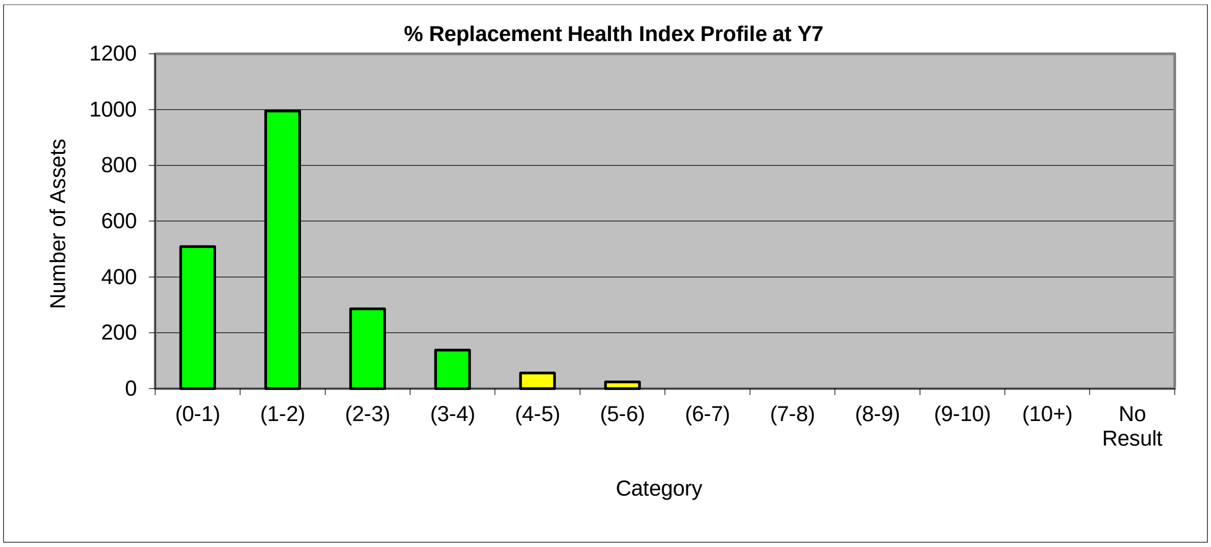
Figure 4-52: Year 7 (2031) Health Index Profile, RMU's



If a 0.15% per annum replacement rate is applied (3 replacements per year) then the health index profile changes as indicated in Figure 4-53.

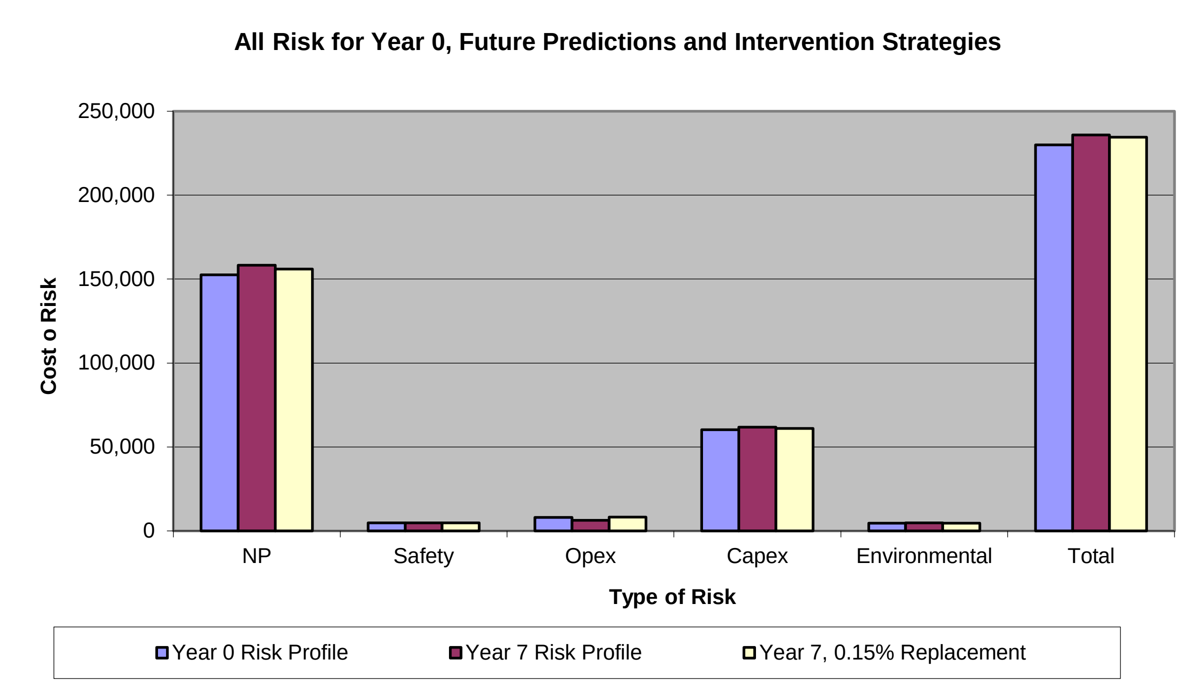
Total risk for all failure scenarios at Year 7 with a 0.15% replacement rate is calculated to be $234k with a predicted failure rate of 3.5 per annum.

Figure 4-53 0.15% Replacement Rate Year 7 Health Index Profile



These results indicate that the health index of the population of Ring Main Units is relatively stable over the forecast period as indicated above due to the young age profile and the expected life of 40 years. As indicated in Figure 4-54 the risks associated with the operation of the Ring Main Unit switchgear family primarily affect the switching flexibility of the network and therefore their risk are to network performance and to a lesser extent capex.

Figure 4-54: Risk Profile for Year 0 (2024) & Year 7 (2031), RMU's



The model forecasts that three Ring Main Units per annum will require replacement over the next 7 years to maintain the risk at current (Year 0) levels. Assets identified as being in poor condition at Year 7 will take priority for consideration of replacement. The forecast replacement volumes included in this strategy include a number of replacements associated with planned replacement programs to address operational and safety issues as well as the condition based failures forecast here.

4.6.4 RISK

4.6.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. An asset criticality assessment was conducted at sub-asset class level by following the Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, formerly JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This also facilitates the ranking of dissimilar sub-asset classes (e.g., transformers and buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

The non-pole type distribution substation asset class has an asset criticality score of AC2 (Moderate). This is due to the potential for failure of a non-pole substation to cause third party damage and injury to JEN personnel and members of the public.

Non-pole type distribution substations contribute to the JEN overall service level performance through reliability and quality of customer supply. There are 2,681 non pole type substations. The number of customers supplied by these substations individually ranges between 1 and 322, therefore a loss of supply from a non-pole type substation has a minor impact on STPIS incentives. The JEN is also configured in such a way that in the majority of customer outages can be minimised through HV switching and LV parallels so that supply to customers can be restored promptly. It should be noted however that this type of substation is generally used to service JEN's high profile customers such as major shopping centres, large sporting venues, show grounds, hospitals and public transport networks. Although the customer numbers may be low from a STPIS perspective the impact of an outage can have a significant impact on JEN's public profile.

4.6.4.2 *Failure Modes*

Failure modes for this sub class include:

- Thermal failure - due to overload, out-of-balance load, and deteriorated or high resistance connections;
- Insulation failure - due to loss of insulation medium (SF6 gas or oil leak), heat and age related winding insulation deterioration, lightning strikes, high voltage injections, switching events, or water penetration;
- Winding failure – winding distortion due to a through-fault;
- Deterioration or corrosion – age and environmental related deterioration of seals, paint, insulation, and connections; and
- Failure due to external factors – such as vehicle strikes, animals, vandalism and weather.

The symptoms of the above failures include:

- Operation of protective devices including blown fuses and circuit breaker trips;
- Excessive heat, hot spots and annealing;
- Molten material and possible fire;
- Internal or external flashover between HV to LV, HV to earth, LV to earth and inter-turn;
- SF6 leak or Oil spill having possible environmental impacts; and
- Distortion of tank, winding, lead supports.

4.6.4.3 *Current Risks*

The consequences associated with non-pole type distribution substation failures are described in Section 4.6.4.2. For details of the risk assessment, refer to JEN's Compliance and Risk System (OMNIA).

The particulars of current risks that have the potential to impact the performance of this sub-asset class are as follows:

- During 2013, a number of kiosks manufactured between 2005 and 2009 failed catastrophically. As a safety measure the operation of 123 kiosks of similar design was restricted via CRO tags. An investigation by the manufacturer found no root cause for the failures but hypothesised that there could have been internal clearance issues causing partial discharge which eventually led to the failures; and
- Another iteration of kiosks has suffered two bushing failures. These issues have been taken up with the manufacturer to identify possible remedies.

The following HV switch types have known issues specific to their design, these switches are either being maintained or are targeted for replacement:

- Schneider RM6s RMU's (manufactured between 1983 and 1987) use SF6 gas as their insulating medium. A number of these units have been found with low gas levels and as a result have degraded insulation systems. A small number of catastrophic failures have resulted from low gas levels;

- Schneider RM6 units (manufactured between 1983 and 1987) also have issues with their spring operating mechanism, over time grease hardens within the mechanism resulting in a misalignment of the semaphore which leads to failure during operation. The manufacturer recommends that these units be maintained to ensure that the grease does not affect the operation;

- Early versions of the Merlin Gerin gas insulated RMU were supplied without any indication of gas pressure. The integrity of these RMU's is dependent on the maintenance of gas pressure within the unit and without a gas pressure gauge operators have no way of ensuring the integrity of the unit prior to performing any operation. A program has been established to retire all RMU's that do not have gas pressure indication (all makes) as they are identified either via the substation inspection program or when reported by operators. There are 36 of these units in service. It is planned that they be retired during the 2023-2026 period. The principal driver of this program is safety and is not expected to materially change overall network reliability performance;

- F & G RMU's were purchased in the 1990's for use in indoor distribution substations at both 22kV and 11kV. When operated at 22kV these units suffered a partial discharge problem in the HV fuse compartment. Modifications were made to the fuse compartments in an attempt to rectify the issue, but this has not proved to be a long term solution. Tracking can occur on the insulating surfaces in the fuse compartment and these RMU's will be retired. There are two units remaining in service, one at 22kV and one at 11kV. These units are to be replaced in conjunction with the RMU replacement program detailed above;

- Calor Emag 22kV air break switchgear has been known to fail when operated due to the drying out of lubricants. These units are being targeted for replacement;

- Siemens 3AC-20N Minimum Oil Breaker have been known to fail to operate. In one case the field personnel attended the site and found that the DC supply was switched off and the batteries were dead. Upon replacing the batteries and ensuring DC supply was restored to the circuit breakers, it was found that the circuit breaker was still inoperable electrically and mechanically. It was found that the circuit breaker required lubrication for a seized mechanism and the interrupters were found to have no insulating medium;

- A number of different types of air break switches have been identified as having high maintenance costs and a probability of failure.

- There are 235 air insulated switches installed in indoor substations. These are primarily arc-chute type isolators configured as fused ring main switchgear to facilitate the isolation of the transformers and HV cables within the associated substations. These arrangements are legacy installations and are not consistent with current design and operating standards. This type of switchgear is comprised of bare 6.6, 11 and 22kV bus conductors generally supported on insulators mounted on the walls and ceilings within the substations. This switchgear has little or no load breaking capability and no fault making capabilities. All apparatus earthing is done using hand applied earths. A program of works is planned to rebuild these installations to remove all bare HV and LV apparatus and install modern fully rated HV ring main switchgear complete with integral earthing switches; and

- Some LV oil filled circuit breakers have been identified with low levels of insulating oil within the interrupting mechanism. These units require manual operation and consequently have no fault making capability. These breakers also have shunt fuse protection schemes that are obsolete and not supported.

Non-pole type substation performance is directly related to customer energy usage, the ability to deliver a compliant level of supply quality and reliability is compromised when a customer's load or export energy demand exceeds the substation cyclic rating.

The uptake of solar generation by customers is rapidly increasing the level of energy being exported into the distribution network. As it grows in capacity it is creating conditions which have never been experienced or planned for when the distribution network was designed. The main impact is on the voltage levels seen by the connected customers. To export energy; embedded generation (EG) systems require the voltage output of the EG to be higher than the network voltage at the customer’s Point of Supply (POS), this facilitates the export of energy back into the distribution network. There is a cumulative effect on voltage rise as more EG systems are connected to the low voltage network. Where voltage drop occurs as a result of increasing load there is now a voltage rise due to the reverse current flows into the network from multiple EG systems. The voltage experienced by the customer can rise above the VEDCoP requirements at the customer’s Point of Common Coupling (POCC). At a localised level the excessive voltage causes inverters to shut down and/or adversely affect QOS limits at both the customer’s premise and neighbouring properties.

EG energy generation does not always occur in sync with energy usage, at the domestic load level peak usage times occur of an evening whereas the majority of energy being exported by solar systems occurs during the day when the sun is shining. This means that distribution substations require the capacity to supply the maximum energy demands of customers loads of an evening without the influence of embedded generation and maintain an acceptable level of supply voltage during the day when embedded generation is at a maximum level. Satisfying these varying network requirements is not always possible with the existing static network elements.

In addition, there is an increase in the amount of non-linear, power electronics and generation from customers’ equipment that affects the ability of distribution substations to deliver a clean, distortion free supply. Non-linear loads, such as DC to AC power converters, switch-mode power supplies, dimmable switches, DC chargers (Electric Cars) and arc furnaces produce harmonics which inherently distort supply voltages creating a dirty supply. The cumulative impact of these types of loads increases the base levels of harmonic distortion which increase the impact of individual localised harmonic distortion. Experience indicates that localised harmonic distortion can exceed the 5% supply voltage VEDCoP distortion limit, leading to the overheating of transformers.

4.6.4.4 *Existing Controls*

All plant and equipment utilised in the construction of these distribution substations undergoes an initial type test by the manufacturers to ensure compliance with the requirements of the product specifications and applicable standards.

Substations installed in the field are constructed to JEN’s standard design requirements and the final construction is audited to ensure compliance. The design and construction standards incorporate the following controls to mitigate against failure events and ensure the required performance is achieved:

- Substation and Plant construction standards (Distribution Construction Manual, Volume 2, Section 3.0 and the Indoor Distribution Substation Procedural Standard – ELE AM PR 0048) – reduce the likelihood of poor construction practices, and the use of non-standard construction methods;
- Clearances, Design & Construction Principles (Distribution Construction Manual, Volume 1, Section 2.6 and the Indoor Distribution Substation Procedural Standard – ELE AM PR 0048) - prevent point of contact between network elements;
- HV OH Switchgear & Cable Head Pole Surge Arrester Installation & Earthing Procedure (JEN PR 0011) – sets out the requirements for the overvoltage protection of high cost equipment to protect against events such as lightning strikes; and

Other operational controls include:

- Enclosed Distribution Substation Inspection Program – 3 to 4 yearly visual inspections to ensure asset integrity;
- Thermographic Surveys – on a 1 to 3 year cycle non-pole type distribution substations along the backbone of the feeder are surveyed to identify hot spots caused by overload and high impedance connections;

- Maintenance process - Plant maintenance notifications are raised and prioritised for the rectification of defects or replacement of assets when identified;
- Non-pole type distribution substation load monitoring – cumulative customer energy load profiling relative to transformer nameplate rating using the JENA application; and
- Quality of Supply monitoring – 5 minute spot voltages, voltage variations and outages are monitored via the JENA application based on AMI (Smart) meter data.
- CRO tagging system to alert network operators to known issues with plant and apparatus.

As part of criticality assessment; consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following the Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). Adequate spares are maintained at the Tullamarine depot.

4.6.4.5 *Future Risks*

Changes in energy profiles due to both changing usage and generation patterns are occurring, and the outcomes of these changes are currently being assessed and modelled. The initial indicators are that there will be an overall increase in energy demand and that the increase will need to be diversified to avoid excessive increases in maximum demands. The most significant impact will come from Electric Vehicle (EV) charging.

As Victoria moves towards a lower carbon footprint there will be a push towards EV’s away from the traditional fossil fuelled vehicles. The energy demands for EV’s will have to be met by the current electricity infrastructure in conjunction with non-network generation. Their demands will add to the daily load profiles and if they follow a similar pattern will increase usage in peak demand periods. Usage will therefore need to be managed to limit their impact on energy maximum demands.

Both off peak and peak usage, will have an impact on the cyclic rating of transformers. Off peak usage will result in load being diversified across a 24 hour period thus reducing the transformer cooling time and as a result, require a reduction in the cyclic ratings to manage the transformers performance. An increase in peak usage will require more capacity to be added to the network increasing the network cyclic rating. Further studies are required to identify the impact that the new energy profiles will have on the cyclic rating of transformers.

However these risks are managed through the Consumer Energy Resources Integration Strategy.

A subsection of JEN’s network has been identified as at risk to flood damage. Revised flood risk modelling conducted by Melbourne Water following the 2022 Maribyrnong River flood has reclassified the location of a number of JEN assets as a high-flood risk zone.[5][6] This creates a number of risks including; the potential for frequent service interruptions during flood events substantial damage to equipment, requiring costly repairs or replacements which would likely be recovered from customers via cost pass through and health and safety risks for JEN staff as flood damage may reduce the integrity of the assets. Relocation of these assets that are in flood zone risk areas needs to be undertaken in the next regulatory period to address the risks to our network and our customers.

[5] Expert Panel Review of Flooding Risk, Progress update on the Maribyrnong River Flood Review - Release of Report | Maribyrnong River Flood Review | Let's Talk | Melbourne Water. October 2022

[6] These assets are located within the Marybong River’s 1% Annual Exceedance Probability (AEP) floodplain, this is commonly recognised as ‘high flood risk’ with additional guidance for building standards within this area. Further details can be found here; Victorian Government, Guidelines for Development in Flood Affected Areas, February 2019

4.6.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy covers time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance.

The principal strategy applied to this sub-asset class is condition based. Maintenance, refurbishment, and replacement activities are driven by the results of a number of formal inspection programs and the CRO protocols. This is supplemented by several proactive replacement programs that are designed to address load related issues and known asset performance issues and risks.

4.6.5.1 *Creation*

Non-pole type distribution substations are created as a result of the following principal drivers:

- requests for new customer load via the Customer Initiated Construction process;
- organic load growth;
- an existing customer's request for an increase in supply capacity; and
- the identification of a maintenance or performance issue that requires augmentation to address.

The need for new or the upgrading of existing distribution substations is either to meet customer load requests or after reviewing the substation loading and confirming overloads from test reports. The Distribution Substation Augmentation Program is designed to address organic load and supply quality related drivers for substation augmentation. Equipment failure is addressed reactively.

JEN has standardised the capacities of non-pole type transformers and kiosk substations to be purchased for general use on the distribution system and these are indicated in Table 4-50 below.

Table 4-50: Standard Non Pole Type Transformers and Kiosk Substations

Type	Capacity (kVA)											
	11/6.6kV		11kV					22kV				
Kiosk	500	-	315	500	1000	1500	2000	315	500	1000	1500	2000
Indoor	500	1000	-	500	1000	1500	2000		500	1000	1500	2000

The number of transformers installed on the distribution network characterised by their kVA rating is indicated in the following figures. Kiosk and padmount types, Figure 4-55, indoor transformers, Figure 4-56 and ground mounted transformers, Figure 4-57.

Figure 4-55: Kiosk and Padmount Type

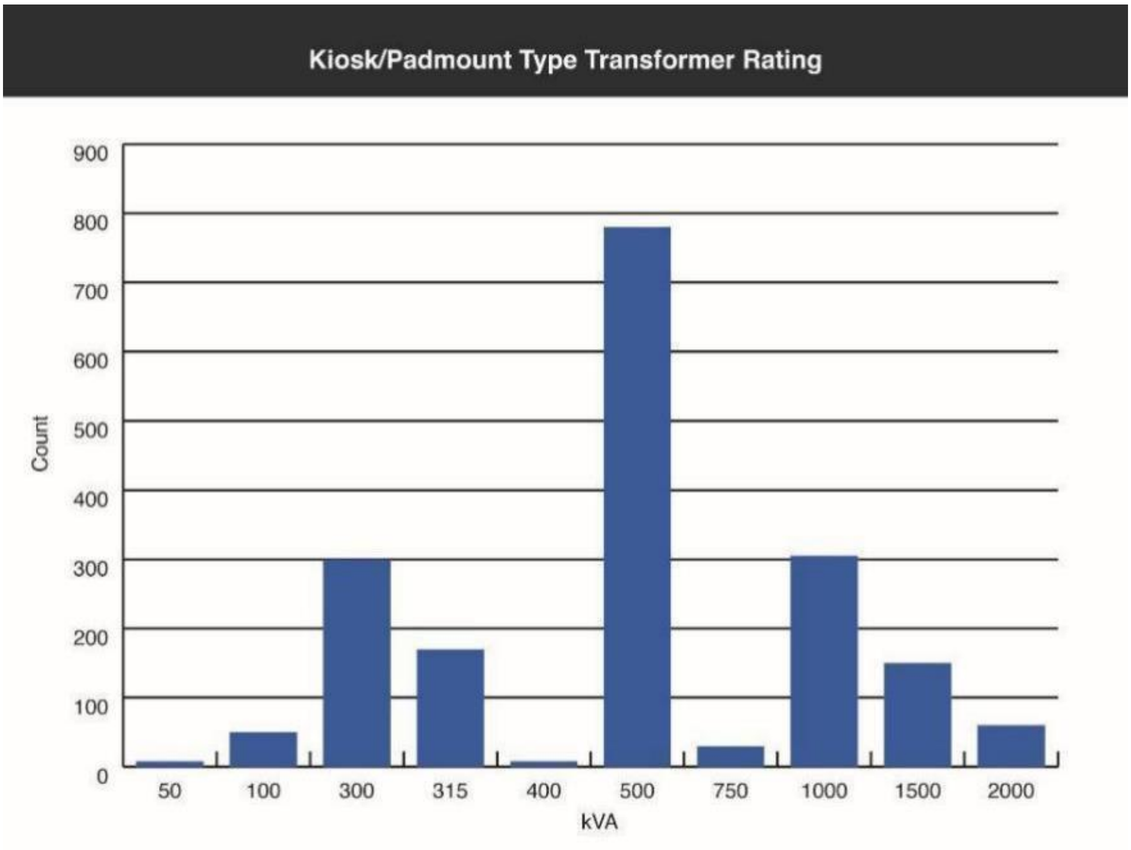
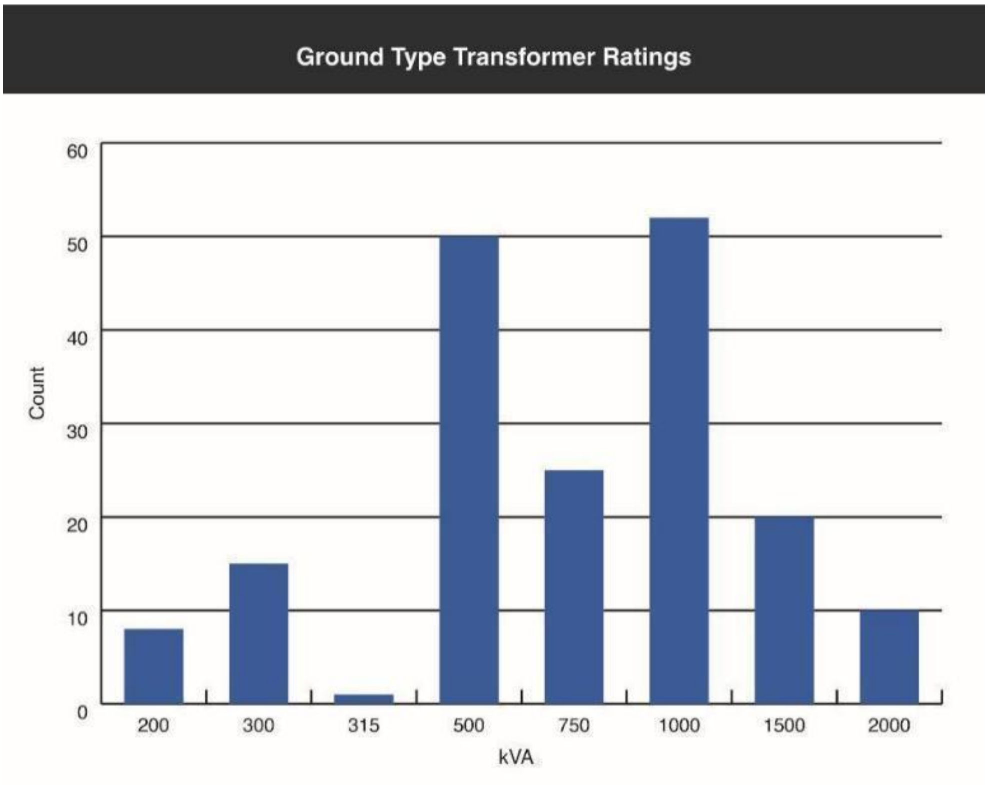


Figure 4-56: Indoor Type

Figure 4-57: Ground Type



4.6.5.2 *Asset Operation and Maintenance*

There are three (3) strategies applied to the management of non-pole type transformers:

- Asset Inspection and Condition Monitoring;
- Preventative Maintenance (Condition Based Replacement); and
- Reactive and Corrective Maintenance.

4.6.5.2.1 Asset Inspection and Condition Monitoring

All non-pole type distribution substations are inspected in accordance with the criteria set out in the JEN MA 0695 - Enclosed Distribution Substation Inspection Manual on a three year cycle in HBRA and a five year cycle in LBRA. All assets within the substations are recorded, with identification, compilation and scheduling of any defects or problems for rectification.

The inspection of these assets includes as a minimum:

- visual inspection of SF6 gas gauges and photographs of pressure gauges with abnormal levels;
- thermal scanning;
- inspection for the effects of corrosion;
- detection of abnormal audible discharge;
- inspection of cable and cable termination conditions;
- checks of transformer and switchgear oil leaks and oil levels; and
- site security.

In conjunction with the above inspection program all non-pole distribution substations located in non-CMEN areas have their earthing installations tested every ten years in accordance with the Earthing Inspection and Testing Plan. This is consistent with the JEN ESMS (refer to section 4.10 Earthing Sub-Asset Class).

For ground-type substations and the associated pole mounted switchgear, switch inspection will be included in the overhead line inspection program.

Defects identified in these inspections are to be scheduled for later repair in logical work packages to minimise the number of times customers are off supply.

Inspection of distribution circuit breakers within indoor and underground substations must be done when opportunities arise and as part of substation inspection and maintenance. Given the physical constraints imposed by switchgear front panels, an inspection will invariably be limited to the following:

- General check for cleanliness;
- Check condition of shunt trip fuses for any signs of creep from the fuse holder and/or deterioration of the fuse wire;
- Check for any obvious wiring insulation failures and/or loose connections;
- Check status and record information such as installation year and type of DC supply systems including batteries and battery charger; and
- Check and record information on the relay (if applicable)

Historically very little information has been retained on file with respect to the switchgear and protection systems employed in JEN non-pole type distribution substations. The initial program has gathered nameplates where possible but has not transferred this information from the photos to the system. Data gathering has a high priority in upcoming inspection programs.

In order to prevent HV indoor distribution switchgear failures due to HV fuse candling all general or back-up type fuses are to be replaced with full range fuses. A list of the correct fuse size for the various transformer sizes can be found in the ELE-999-GL-EL-001, previously JEN GU 0500 – JEN Fusing Guideline. If a suitably sized full-range fuse is not available, the fused switchgear should be replaced with a modern CB ring main unit.

Families of HV switchgear identified as being problematic or prone to failure will be phased out.

A planned replacement program will be introduced for all distribution substation DC supply systems, such as batteries and chargers, as these units require ongoing maintenance and have proved to be unreliable. Upcoming asset inspection programs should be used to collect information on substations with DC supplies.

Any LV switchgear found in a damaged condition, in an inoperable condition or with obvious overheating deterioration shall be replaced.

Buildings that contain asbestos are a potential health and safety risk. The replacement or major refurbishment of buildings may be governed by legislative changes in the future, requiring the safe removal of all asbestos within specified timeframes.

Suitably sizing substations will not only improve the quality of supply for customers but will generate improvements in supply reliability as the risks of failures will be reduced when the networks capacity is designed to align with customer loading demands. These improvements will include a reduction in the risk of network losses that are elevated when distribution transformers are overloaded, a reduction in the risk of environmental issues associated with oil leaks from overloaded/overheated transformers and a reduction in the risk of fire starts caused by catastrophic failures. The utilisation of distribution substations is reviewed as per the Distribution Substation Augmentation Program. For details, refer to the Distribution Substation Augmentation, Network Development Strategy ELE PL 0017.

The indoor transformers and kiosk substations which are taken out of service as a result of the augmentation program are then assessed in accordance with the requirements for refurbishment. When substations are removed from service for reasons other than defect repair, such as load growth, load decrease, noise, redundancy or maintenance, they are assessed using the criteria set out in the Distribution Transformer Refurbishment Procedure – ELE AM PR 0047, Substations that satisfy the criteria shall be refurbished and returned to stock for future use. Those that do not meet the criteria shall be scrapped.

The replaced substation will be assessed according to the below criteria to determine if the substation should be refurbished and returned to service or be scrapped:

- PCB Contamination;
- Voltage ratio and tapping range;
- Conditions including, internal faults, brown porcelain bushings, rust, impacts, distortion, confirmed noise complaints;
- Age and capacity;
- Configuration, size and weight; and
- Cost of refurbishment.

Kiosks shall also be checked for:

- Ring main switchgear with no gas pressure indicator;
- “Compact” LV switchgear with J type fuses;
- Oil insulated HV switchgear that is not fully fault rated; and

- Substantial corrosion or rust on the enclosure.

For more information, refer to Distribution Transformer Refurbishment Procedure – ELE AM PR 0047.

Generally Ring Main Units are not refurbished. They are typically tested and reused if they are still performing within specification. Otherwise, they are disposed of according to JEM PO 1600 – Scrap Materials.

Refurbishment shall only be carried out if the refurbishment cost is less than the residual substations value as described in the Distribution Transformer Refurbishment Procedure – ELE AM PR 0047.

The typical tapping range for old transformers is between 100% and 90% for 415/240V transformers and 102.5 to 92.5% for 433/250V transformers, these ranges fall outside of the retention range of 105-95% as depicted in the Distribution Transformer Refurbishment Procedure – ELE AM PR 0047. In general, transformer tapping ranges are not clearly defined in existing records. An emphasis will be placed on identifying and documenting the tapping range and set tap position while conducting upcoming Inspection programs.

4.6.5.2.2 Preventative Maintenance

4.6.5.2.2.1 Proactive Replacement

Proactive replacement programs are used whenever an issue is identified that has risk that requires management.

The following switchgear types will be targeted for proactive replacement.

- Gas filled RMU's without gas gauges;
- F&G RMU's;
- Calor Emag air insulated 22kV switches; and
- Indoor arc chute type isolators and bare HV bus systems.

In addition, problematic air break switches are CRO tagged and labelled as inoperable. Each year, condition information and failure history will be reviewed and priorities established for switchgear replacement in the following year within the planned CRO Switch replacement program.

4.6.5.2.2.2 Condition Based Replacement

The condition of non-pole type substations and the associated transformers is monitored via the substation inspection program and the thermal survey program. In addition, the operating environment as defined by transformer loads is monitored via the JENA application which uses connectivity data from GIS and AMI energy data to measure and report on the load profiles for the various elements of the distribution system.

The results of this condition monitoring activity is used to drive the condition based replacement of non-pole type transformers.

Transformers are designed for operation with an ambient temperature of up to 40ºC and a maximum top oil temperature rise of 60ºC above ambient at full load. Operating temperatures that exceed these limits can result in the degradation of the transformers insulation systems, initiate oil leaks and cause catastrophic failures. Transformers housed in enclosures such as indoor substations and kiosk substations have their cooling impacted by the enclosure and consequently the cyclic rating of these transformers is constrained. The management of substation loads via accurate substation loading data and load profiles are essential to ensuring that transformers achieve their designed asset life.

The secondary voltage ratings of distribution non-pole type transformers do not align with Australia's nominal supply voltages and the difference creates inconsistencies in the current ratings in ampere between network supply capacities and customer loads. A change in the standard transformer secondary voltage from 415/240V to 433/250V was adopted approximately 30 years ago, following this, the Australian nominal voltage shifted from 415/240V to 400/230V. Discrepancies between transformer rated and customers nominal voltages have widened with these changes. As a result, a transformers' rated current is 8% lower than customers nominally rated current for an equivalent load expressed in kVA. That is to say that there is a difference between the currents associated with loads expressed in kVA that is dependent upon the voltage reference. A future adoption of a 400/230V secondary voltage would result in the need to increase the current carrying capacity of network elements required to deliver a particular load in kVA.

Transformers are static and not subjected to wear and tear, the only moving component is the off-load tap changer which is rarely adjusted and only when the transformer is isolated from supply. Consequently, there are no ongoing wear related maintenance requirement for transformers when operating within their capabilities.

The HV switchgear on the other hand has moving components and is used to operate and isolate various network elements. The condition of HV switchgear and its functional health is managed via condition based maintenance. This is informed by a number of inspection programs and the CRO protocol.

4.6.5.2.3 Reactive and Corrective Maintenance

Reactive and corrective maintenance is carried out when faults occur or after asset inspection programs identify any urgent maintenance, for example, in service electrical faults or excessive oil leaks.

Undersized Neutrals, refer to section 1.3.5.3

4.6.5.3 *Non-Pole Type Transformer Forecast Replacement Volumes*

As detailed in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

Table 4-51 lists the forecast replacement volumes for non-pole type distribution substations from 2025 to 2031 required to maintain network performance at current levels. In addition to this the Distribution Substation Augmentation Program drives the replacement of overloaded substations.

Table 4-51: Non-Pole Type Distribution Substations Forecast Replacement Volumes

Unique ID	Service Code	Non-Pole Type Distribution Substations	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A243	RHD	Transformer Ground/Indoor	10	8	9	9	9	9	9
A143	RHE	Indoor/Kiosk RMU Gas Gauges & Fault Replacement	1	-	2	3	3	3	3
A148	RHK	Transformer/Substation Failure Kiosk	2	2	4	4	4	4	4
A108	RHM	Kiosk Refurbishment	6	6	6	6	6	6	6
A142	RHF	LV Switchgear Replacement	1	2	2	2	2	2	2
A195	RHF	Distribution S/S switchgear replacement (indoor and ground type)	-	-	32	75	72	70	68
A399	RHF	Compact LV boards (J type fuses) in indoor subs	-	-	6	15	14	14	14

4.6.5.4 *Asset Disposal*

Failed or damaged substations that are considered unsuitable for refurbishment are scrapped. The substation is taken out of service, returned to the depot, and stored in a bunded area. The substation oil is tested for PCB content and disposed of appropriately under a contract arrangement.

As a result of the initial EDSIP, a total of 81 non pole type distribution substations containing asbestos were identified, primarily found in cable entry conduits, arc chute type air-break switchgear and zelamite switchboard materials. Following the Enclosed Substation Inspection Notification (ESIN) project, an external asbestos contractor has been engaged to undertake regular audits (5-year cycle) of the substations found to contain asbestos. All effected sites have been risk assessed and recorded in JEN's asbestos register. The condition of the asbestos containing equipment is monitored so as to manage the risk associated with historically installed asbestos.

Disposal of all materials shall be in accordance with JEM PO 1600 – Scrap Material Policy.

4.6.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who engage in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.6.5.6 *Spares*

Emergency non-pole type distribution substation stock is determined based on the quantity of the items in service on the network and its historical usage. Emergency stock levels are shown in Table 4-52.

Table 4-52: Non-Pole Type Distribution Substation Emergency Stock Levels

Material	Material Description	Min	Max. level
11000018	TRANSFORMER,11-6.6KV/433-250V,1000KVA, CE	1	1
11002271	KIOSK,22KV/433V, 500KVA, IFT,4FS	2	2
11004361	TRANSFORMER,11-6.6KV, 500KVA,3P,433V, CE	2	2
11004377	TRANSFORMER,11KV,1500KVA,3P,433-250V, CE	1	1
11004794	TRANSFORMER,22KV/433-250V 2000KVA 3PH CE	1	1
11004804	TRANSFORMER,22KV/433-250V 500KVA 3PH CE	1	1
11004813	PAD,22KV/433V 100KVA LOOP THROU,1 FS	1	1
11004817	KIOSK,22KV/433V, 500KVA, RING,4FS	2	2
11004819	TRANSFORMER,22KV/433-250V 1000KVA 3PH CE	2	2
11005057	TRANSFORMER,11KV,1000KVA,3P,433-250V, CE	1	1
11005247	PAD,22KV/433V, 315KVA, RING, 4FS	2	2
11005248	PAD,22KV/433V, 500KVA, RING,4FS	4	4
11005249	PAD,22KV/433V,1000KVA, RING,1FS	2	2
11005251	PAD,22KV/433V, 2000KVA, RING,1FS	1	1
11005252	PAD,11-6.6KV/433V, 500KVA, RING, 4FS	1	1

Material	Material Description	Min	Max. level
11005352	TRANSFORMER,22KV,2000KVA,3P,433-250V	1	1
11005369	PAD,22KV/433V, 500KVA, RAD, 4FS.DNR	1	1
11005420	PAD,11-6.6kV/433V,1500KVA, RMU	1	1
11012802	TERM, TEE SPLICE, FOR PIN ELBOWS	1	2
11012821	PAD,22KV/250V,50KVA, LOOP THRU,1PH	0	0

4.6.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determine the information required to manage and operate an Asset Class.

The Electricity Distribution ACS facilitates the safe, efficient and reliable delivery of electricity to JEN's customers.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives (Table 4-53).

Table 4-53: Non-Pole Transformer Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-54 below identifies the current and future information requirements to support the Asset Class's critical decisions and their value to the Asset Class.

Table 4-54: Non-Pole Transformer Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Non-pole transformers acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied non-pole type substations and associated plant and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Sub Name - Type - Operating level - Feeder - Circuits - Date Installed - Live Line Clamp - CMEN - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Utilisation • Load balance on each circuit by phase • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-55 provides the information initiatives required to provide the future information requirements identified in Table 4-54. Included within this table is the risk to the Asset Class from not completing the initiative.

Information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

Table 4-55: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improve/review MAT Code definitions	Ability to align to AER service classification structure.	High	Precise definition
Improved Asset Attributes	Review current asset attribution fields to ensure attributes being collected are asset specific.	Medium	Appropriate and Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.7 OVERHEAD LINE SWITCHGEAR SUB-ASSET CLASS

4.7.1 INTRODUCTION

The overhead line switchgear sub-asset class applies to pole mounted:

- HV air insulated load break switchgear;
- HV gas insulated load break switchgear;
- HV disconnectors (isolators and live line clamps); and
- LV isolators, LV fused isolators, LV ABC isolators and LV ABC fused isolators.

There are approximately 431 HV air break switches, 2,038 HV disconnectors, and 1,317 gas switches installed on the JEN. There are 232 high voltage (HV) feeders on JEN and each feeder supplies an average of 1,613 customers. Each feeder has an average of 2 air break switches, 9 sets of isolators and 6 gas switches; therefore, a failure to operate can adversely affect the operational efficiency and flexibility of the network.

The gas insulated switches come in two forms, manual and remote controlled. The remote controlled units together with remote controlled Automatic Circuit Breakers (ACR's) are the principal devices used to facilitate the remote control and automation of the distribution network.

There are an estimated 13,000 LV three phase switching devices on the LV overhead network. These are hook stick operated switch links and fused isolators of two types. Those that are bare, generally crossarm mounted, and designed for use with the open wire LV system and those that are insulated and designed for use with aerial bundled conductor LV distribution systems or LV ABC. Some of the LVABC devices are three phase gang operated and some are three phase sets comprised of single phase units (These are sometimes referred to as Krone boxes or FSD's).

The details of all LV switching devices are stored in the GIS and SAP systems however, on a macro scale it is difficult to distinguish between those that are installed on the overhead LV network and those that are installed in switching cabinets or non-pole type substations.

Table 4-56 provides details of the number of HV overhead switchgear installations, by type and operating voltage, on the JEN.

Table 4-56: HV Overhead Line Switchgear

Overhead Switchgear Type	Operating Volume			Total
	22kV	11kV	6.6kV	
Air Break Switches				
Arc Chute	31		1	32
Ganged Arc Chute	191	3	2	196
Ganged Flicker Blade	144	59		203
Horn Deflector	1			1
HV Disconnectors				
Isolator	1,304	283	187	1,774
Ganged Isolator	1			1
Live Line Clamp	234	28	1	263
Gas Switch	**1,115**	**166**	**36**	**1,317**
Total	**3,021**	**539**	**227**	**3,787**

4.7.2 ASSET PROFILE

4.7.2.1 *Life Expectancy*

As prescribed in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for HV overhead switches is 50 years and 45 years for LV pole tops (which includes pole mounted LV switchgear).

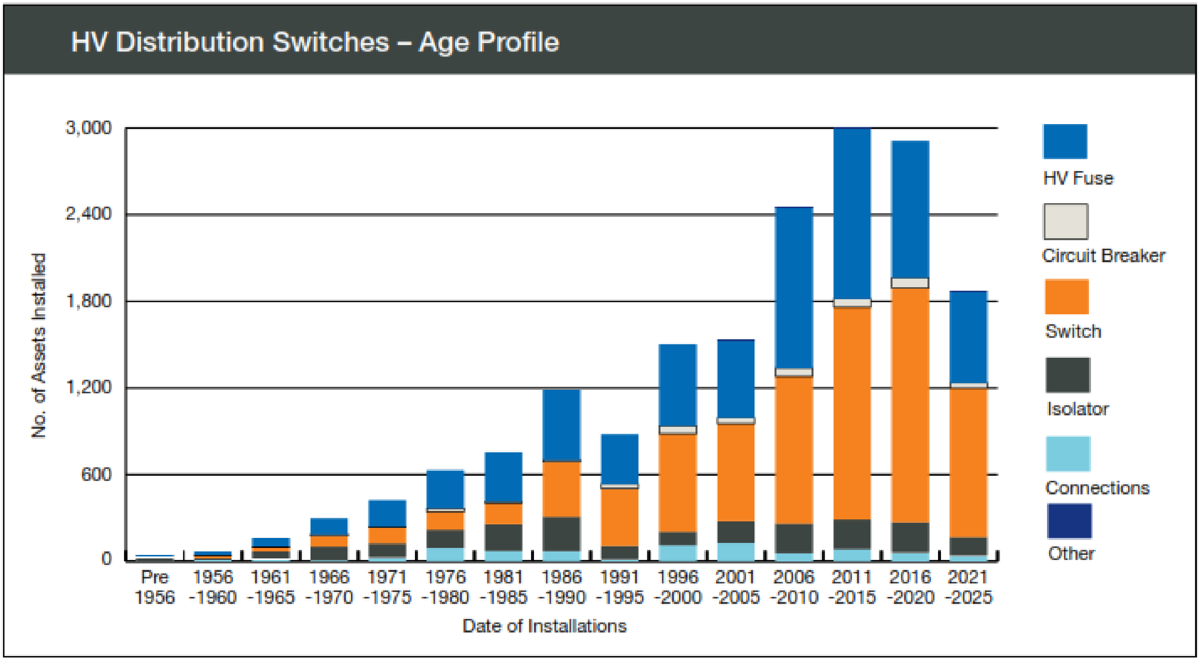
This Procedure lists asset useful lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has undertaken a number of reviews of asset useful lives utilizing consulting agencies and cross-referencing other DB's. With the increasing knowledge and experience on the asset performance of overhead gas switches, manual operated and remote controlled, the useful lives of this asset category within the HV overhead switches family are likely to be reduced in the next review of the procedure.

4.7.2.2 *Age Profile*

There are approximately 3,800 pole mounted HV overhead switches installed on the JEN. These include air break type switches, disconnectors (isolators and live line clamps) and gas switches. The age profile of the HV overhead switchgear population is shown in Figure 4-58. Fully enclosed, metal clad, gas insulated load break, fault make, switches have been installed on JEN as standard equipment since 1995. Air break switchgear has not been used as standard since this time due to problems associated with bird and animal strikes and maintenance requirements. A small number of air break switches have been installed since 1995 but it is probable that these are specialised, high capacity, project specific installations.

Consequently, the mix of switch types in this sub asset class is changing with the population of air break load break switches slowly being retired and replaced with gas switches. To a lesser extent this is also happening with HV isolators.

Figure 4-58 Age Profile of HV Overhead Switches



4.7.2.3 *Utilisation*

The HV and LV overhead switchgear is used to facilitate maintenance and construction activity and to reconfigure the network and manage network load. Automated or remote controlled HV gas switches facilitate the remote control of the network and are critical to JEN's future plans for self-healing network capabilities.

4.7.3 PERFORMANCE

4.7.3.1 *Requirements*

The requirements for all new overhead line switchgear are set out in JEN's technical specification for the purchase of this equipment. This specification sets out the performance standards to be met and the design features of the switchgear. The specification references a number of Australian Standards. Unless otherwise specified, all HV overhead line switchgear shall be designed, manufactured and tested in accordance with the following Australian Standards (refer to Table 4-57).

Table 4-57: Relevant Australian Standards

Standard	Title
AS 1852.441	International Electrotechnical Vocabulary – Switchgear, Control gear and Fuses
AS/NZS 60265.1	High-Voltage Switches – Switches for Rated Voltages above 1kV and less than 52kV
AS 62271.1	High-voltage switchgear and control gear – Common specifications
AS 62271.200	High-voltage switchgear and control gear – A.C. metal-enclosed switchgear and control gear for rated voltages above 1kV and up to including 52kV
AS 62271.102	High-voltage switchgear and control gear – Part 102 Alternating current disconnectors and earth switches

Standard	Title
AS/NZS IEC 60947.3	Low-voltage switchgear and control gear – Switches, disconnectors, switch-disconnectors and fuse-combination units

The equipment must be able to operate with the required performance parameters when exposed to climatic conditions in the state of Victoria.

Load break switchgear shall have the following features:

- Load breaking capacity equal to its rated current;
- Fault current making capacity to match the network design fault levels;
- Short circuit withstand levels that match the network design fault levels;
- Lighting impulse withstand level of 15kV for the 22kV network; and
- A.C. dielectric withstand levels between phases, to earth and across the open contacts that comply with the requirements of the above standards for the nominated operating voltage.

Disconnectors shall have the following features:

- Short circuit withstand levels that match the network design fault level;
- Lighting impulse withstand level of 150kV for the 22kV network; and
- A.C. dielectric withstand levels between phases, to earth and across the open contacts that comply with the requirements of the above standards for the nominated operating voltage.

In addition, pole mounted gas switches (manual and remote controlled) are required to have an indicator to show the gas pressure level and a ”Low Gas” lockout feature which will be activated upon reaching an unsafe gas pressure level. The indicator must be clearly visible from the ground when mounted on the pole structure and give a clear indication of the serviceability of the switch.

The requirements for the installation of overhead line switchgear are specified in the JEN Distribution Construction Manual (ELE 999 OM CN 001). This includes the requirements for the installation of overvoltage protection on normally open switches.

4.7.3.2 *Assessment*

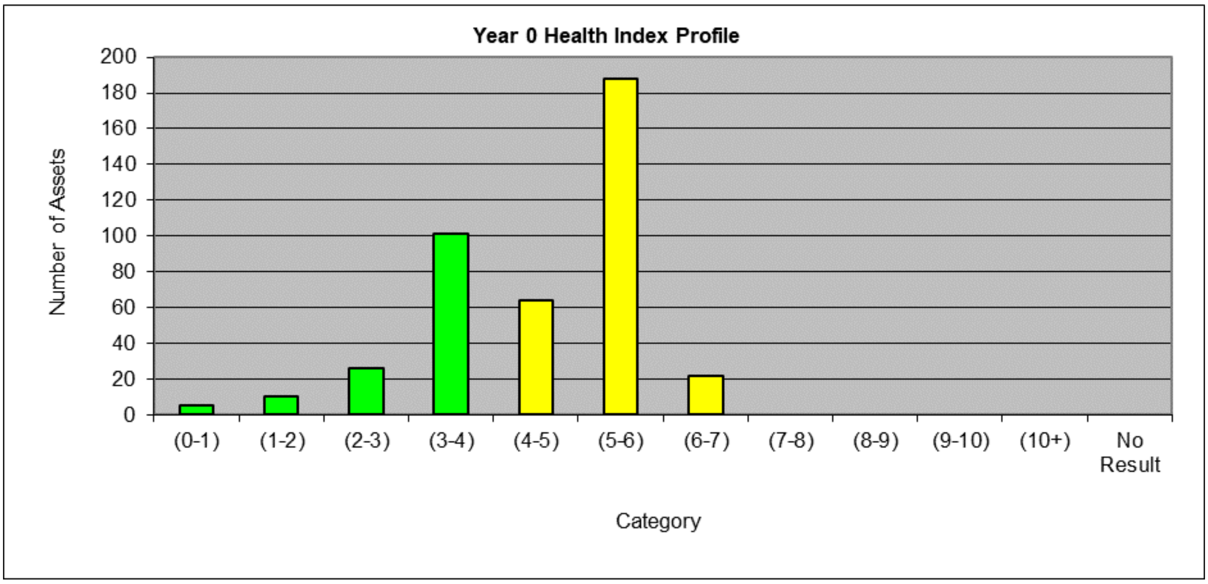
The operational performance of overhead switchgear is assessed by the examination of fault reports and the monitoring of maintenance notifications that relate to overhead switchgear. In addition, the Caution Re Operation (CRO) tagging system which is used to identify problems associated with the operation of distribution switchgear also provides a clear indication of the condition of this equipment.

4.7.3.2.1 CBRM Assessment – Air Break Switches

The results of the CBRM modelling indicate that the current (Year 0) health index is as shown in Figure 4-59.

The total cost of risk for all failure scenarios at Year 0 is calculated to be $192k with a current failure rate of 3.28 per annum. These failures can range from a minor failure (maintenance work required) to a major failure that includes replacement of the unit.

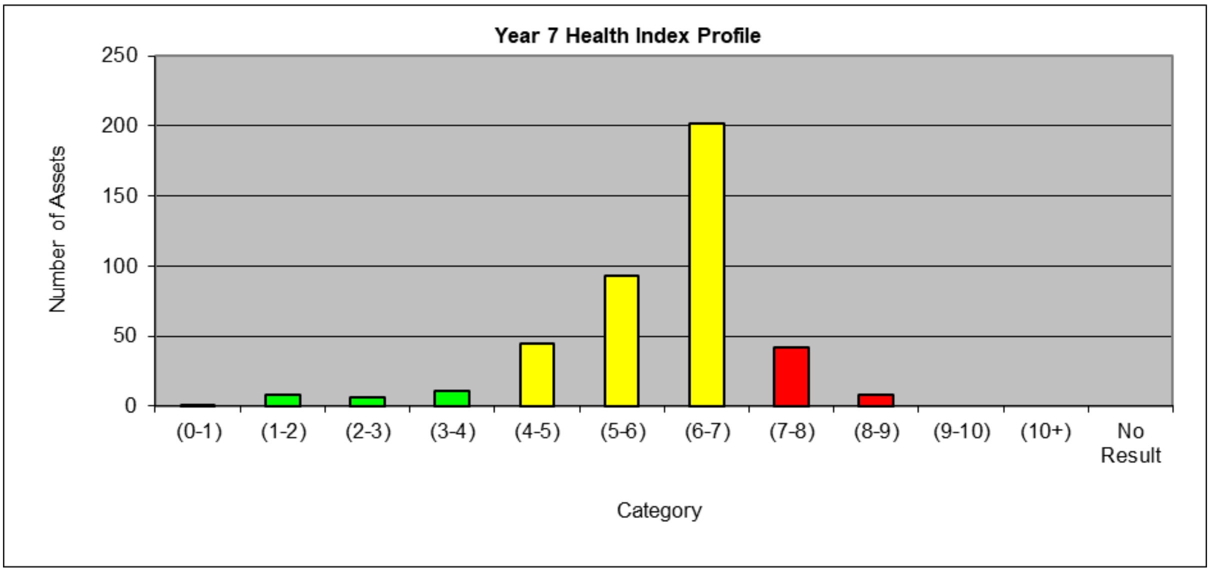
Figure 4-59: Year 0 Health Index Profile, Air Break Switches



If asset replacement is deferred until 2031 (Year 7) the health index deteriorates as shown in Figure 4-60.

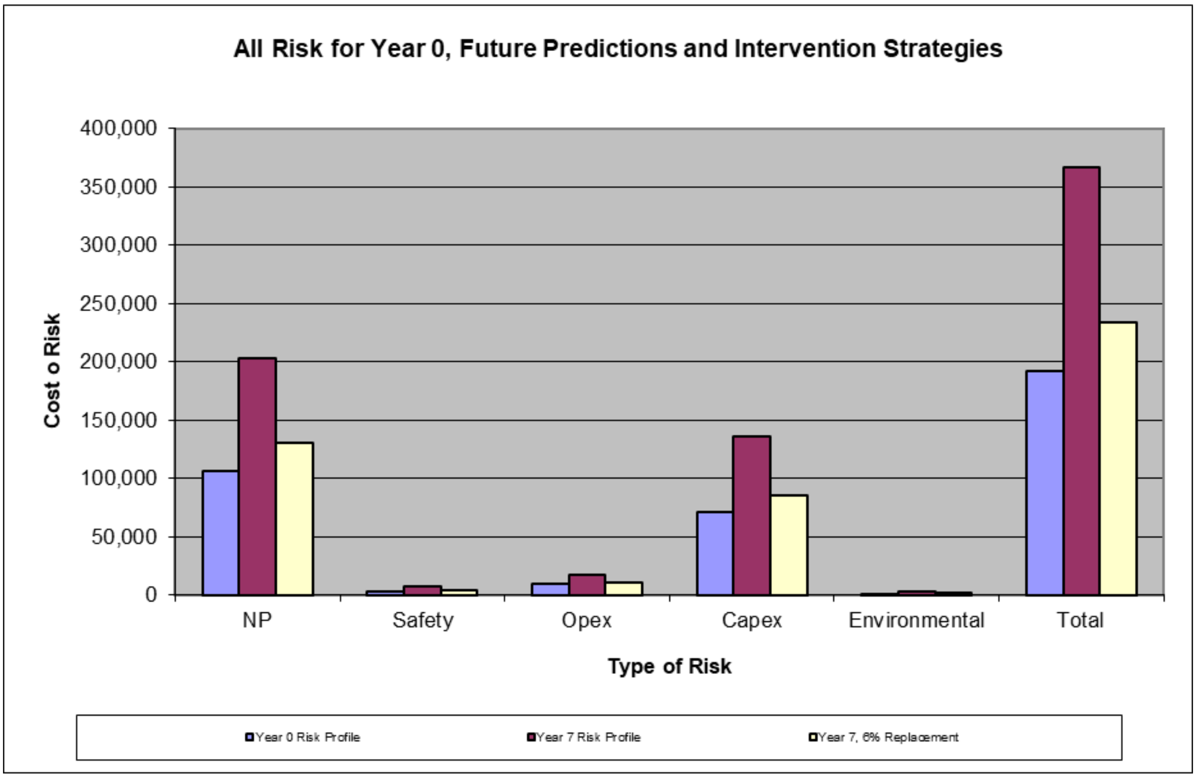
The total cost of the risk for all the failure scenarios at Year 7 is calculated to be $366k with a predicted failure rate of 6.2 failures per annum.

Figure 4-60 Year 7 Health Index Profile, Air Break Switches



The forecast health index at year 7 indicates that the population of air break switches are approaching their expected useful life. Switchgear and isolator failures affect the switching flexibility of the network, therefore the consequence of failure is primarily related to the network reliability and the STPIS incentive as indicated in Figure 4-61.

Figure 4-61: Risk Profile for Year 0 & Year 7, Air Break Switches



The CBRM model for air-break switches is used to assess the current risk level in in terms of the cost of the risk and failure rates. The model can then be used to forecast the risk level for various scenarios, such as do nothing and various asset replacement and maintenance strategies.

Figure 4-61 above indicates the current level of risk (at year 0), the level of risk at year 7 if no replacement occurs and the risk at year 7 if 6% of the air-break switches are replaced each year.

To maintain the risk profile for air-break switches at approximately current levels (year 0) the model forecasts a need for a 6% per annum replacement rate which is equivalent to a total of 25 air break switch replacements per annum over 7 years. The actual air-break switch replacements will continue to be driven by the results of the various inspection programs and CRO tagging system.

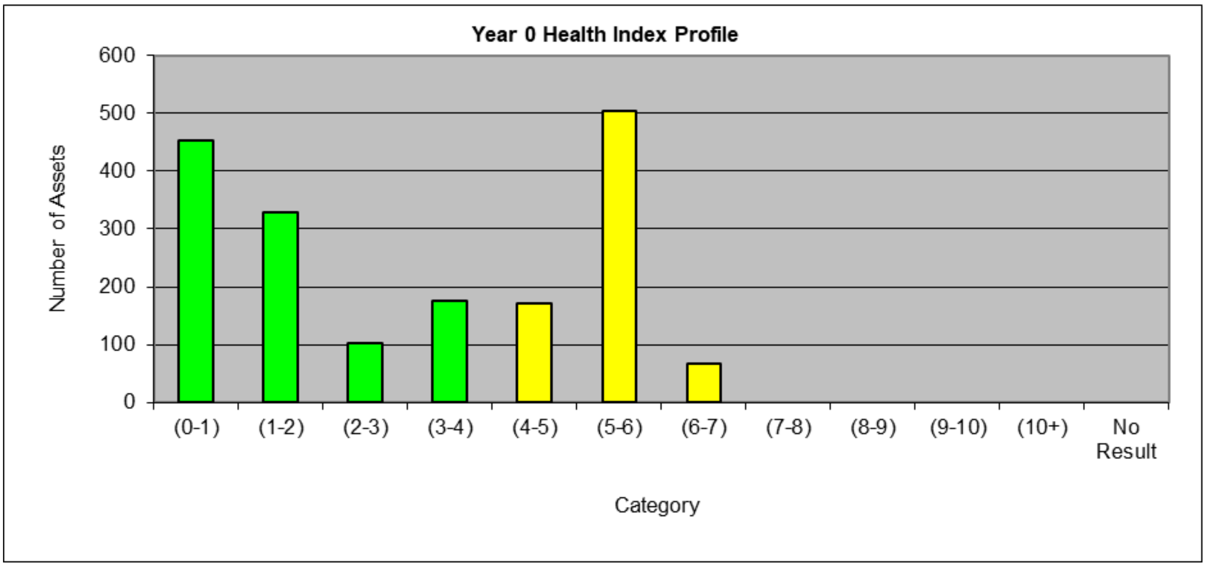
In order to maintain the assessed risk associated with the operation of these assets at current (year 0) levels this strategy proposes an increase in the current replacement rates to approximately 25 air break switches per annum with gas switches over the course of the next 5 years. As air-break switches are obsolete they are either removed completely or replaced with manual or remote controlled gas switches or ACR's when required. The CBRM model generates a list of the highest priority replacements based on health index to assist with and planned replacement program.

4.7.3.2.2 CBRM Assessment – HV Isolators

The results of the CBRM modelling indicate that the current (Year 0) health index is as shown in Figure 4-62.

The total cost of risk for all failure scenarios at Year 0 is calculated to be $900k with a current failure rate of 15 per annum. These failures can range from a minor failure (maintenance work required) to a major failure that includes replacement of the unit. In general replacement is the most common maintenance activity for this asset type.

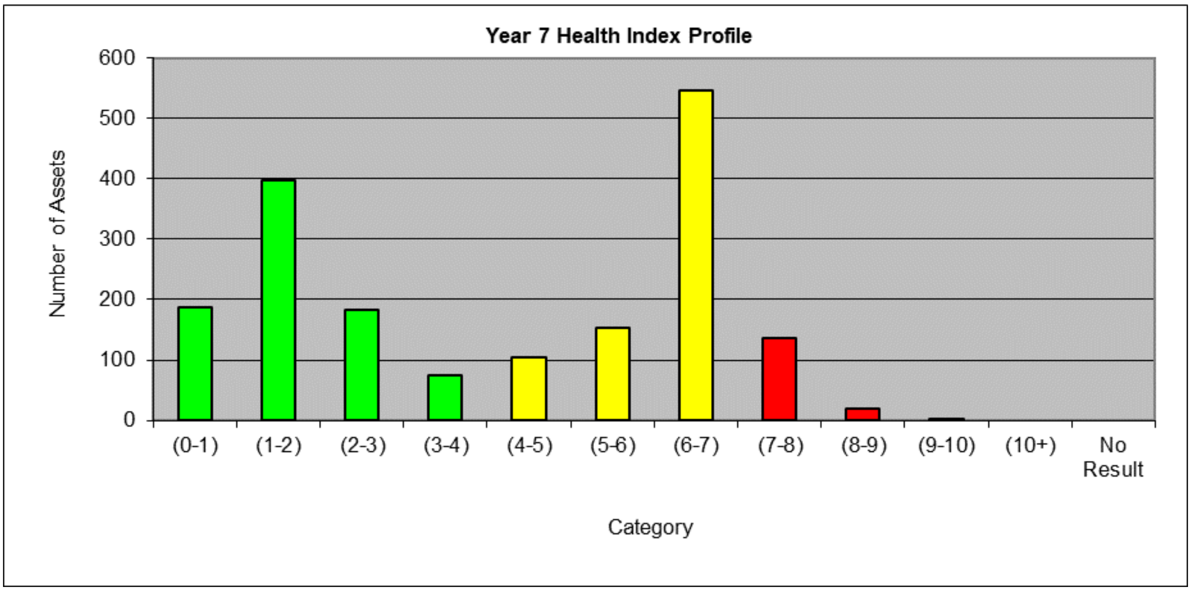
Figure 4-62: Year 0 Health Index Profile, HV Isolators



If proactive replacement is deferred until 2031 (Year 7) the health index deteriorates as shown in Figure 4-63.

The total cost of the risk for all the failure scenarios at Year 7 is calculated to be $1,466k with a predicted failure rate of 25 failures per annum.

Figure 4-63: Year 7 Health Index Profile, HV Isolators



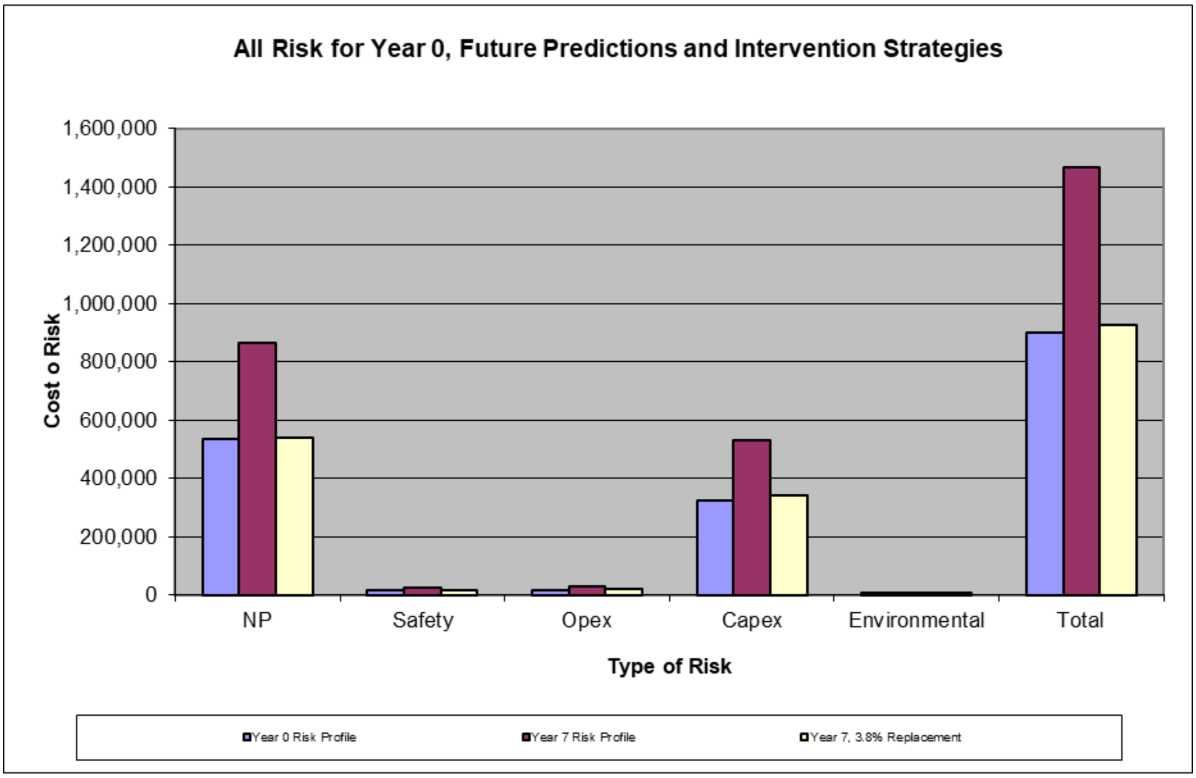
Switch and isolator failures affect the switching flexibility of the network, therefore the consequence of in service failure is primarily related to the network reliability and the STPIS incentive as indicated in Figure 4-64.

The CBRM model for HV isolators is used to assess the current risk level in terms of the cost of the risk and failure rates. The model can be used to forecast the risk level for various replacement scenarios, such as do nothing and various asset replacement and maintenance strategies.

Figure 4-64 indicates the current level of risk (at year 0), the level of risk at year 7 if no replacement occurs and the risk at year 7 if 3.8% of the HV isolators are replaced each year.

To maintain the risk profile for air-break switches at approximately current levels (year 0) the model forecasts the need for a 3.8% per annum replacement rate which is equivalent to a total of 68 HV isolator replacements per annum over 7 years. The actual HV isolator replacements will continue to be driven by the results of the various inspection programs and CRO tagging system. The options for the replacement of HV isolators include removal, like for like replacement or replacement with a gas switch or an ACR where required.

Figure 4-64: Risk Profile for Year 0 & Year 7, HV Isolators



In order to maintain the assessed risk associated with the operation of these assets at current (year 0) levels this strategy proposes an increase in the replacement rate to approximately 68 HV Isolators per annum over the next five years.

4.7.3.2.3 CBRM Assessment – Gas Insulated Switches

Gas insulated switches have been deployed on the network since approximately 1990 in both the manual and remote controlled form. As such the age of the population is quite young with the oldest units at approximately 60% of their expected life. No units will exceed the expected life by 2029.

In October 2022 an incident occurred in which a gas gauge fell from a pole mounted ILJIN 24kV SF6 gas load break switch on the United Energy Network during operation. The incident was caused by corrosion of the aluminium gas gauge. Following this incident, JEN's population of 238 Iljin switches has been inspected and assessed. It has been identified that over 54% of the JEN Iljin switches have an aluminium gas gauge showing signs of deterioration. In addition to the corroded gas gauge, some of the ILJIN switches low gas interlocking mechanism have found seized, and not functioning as required due to the build-up of corrosion, dirt and grime during performance testing. Although it has also been noted on other networks that the pressure relief device on the end of the tank is made of aluminium and may be prone to corrosion, this has not been observed on the JEN during inspection. As a result of these defects and the associated safety hazards, a replacement program has been initiated. In addition, all Iljin switches are flagged for opportunistic replacement. Due to the timing of the incident investigation, the Iljin switch defects have not been included in the CBRM modelling, but may have a significant influence on the CBRM models in future.

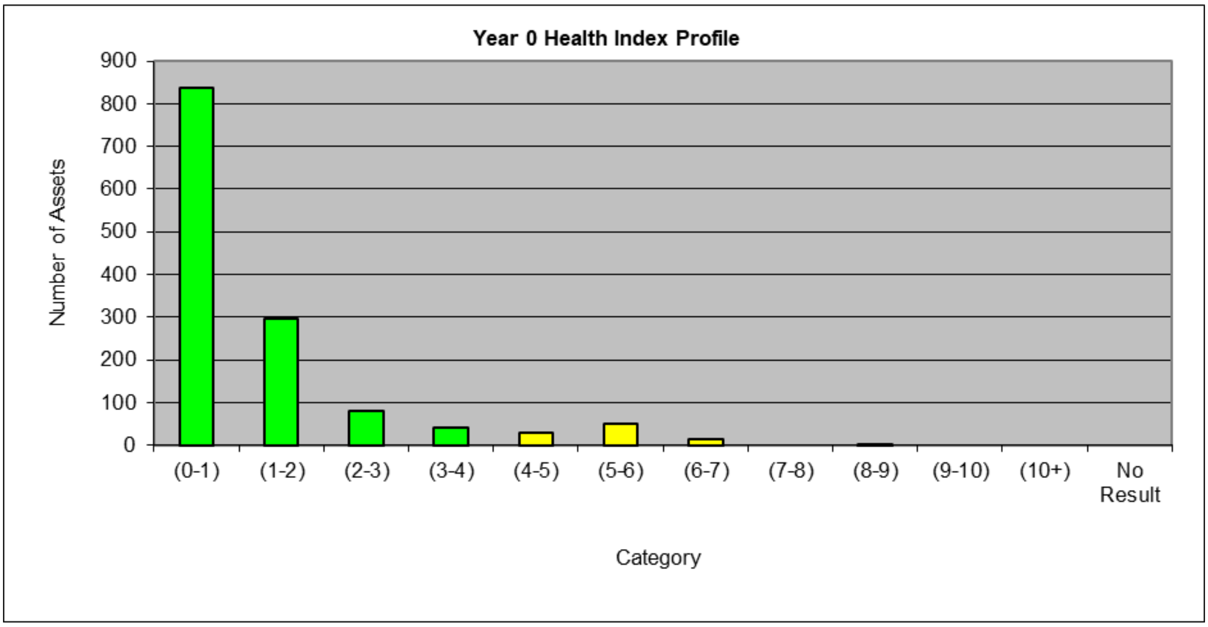
The only other common issue relates to minor defects associated with the communications facilities on the remote controlled gas switches. There is a currently developing issue with batteries swelling in NGK remote controlled switches. Also there are two units which were in service for less than a year, locked out from operation due to its gas pressure dropped below the safe operation level. These defects are under investigation and have not been included in the CBRM modelling.

There have been some units damaged by direct lightning strike.

The results of the CBRM modelling indicate that the profile of the current (Year 0) health index is as shown in Figure 4-65.

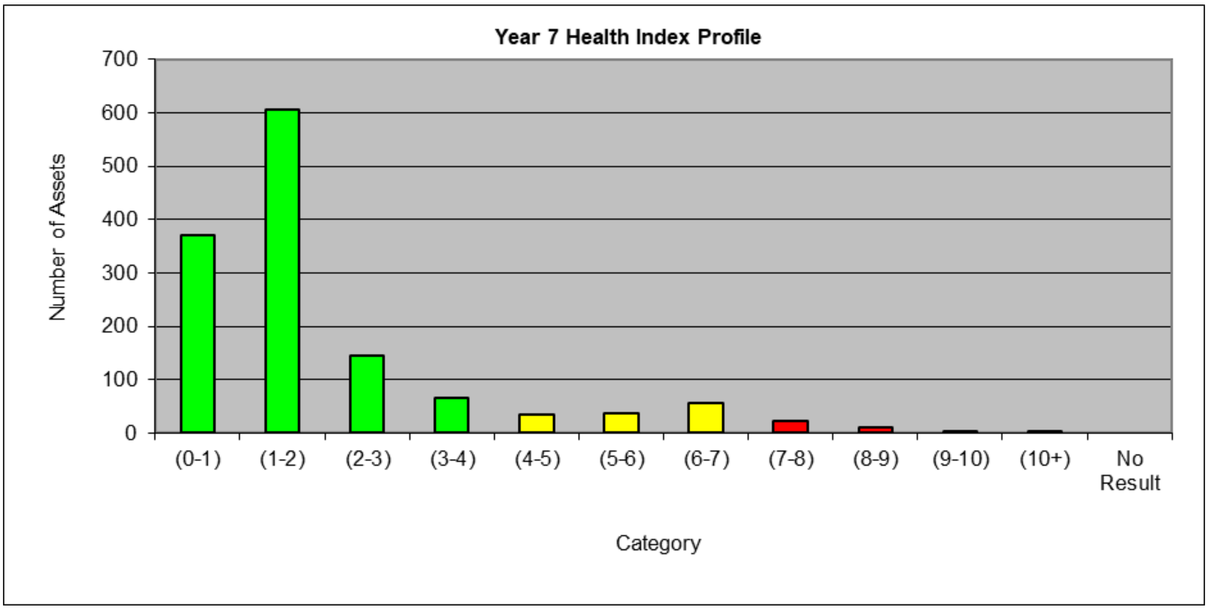
The total cost of risk for all failure scenarios at Year 0 is calculated to be $492k with a current failure rate of 28 failures per annum. These failures are all categorised as minor failures (maintenance work required) associated with the communications facilities. The current population have health indexes that reflect the relatively young age of this asset class.

Figure 4-65 Year 0 Health Index Profile, Gas Switches



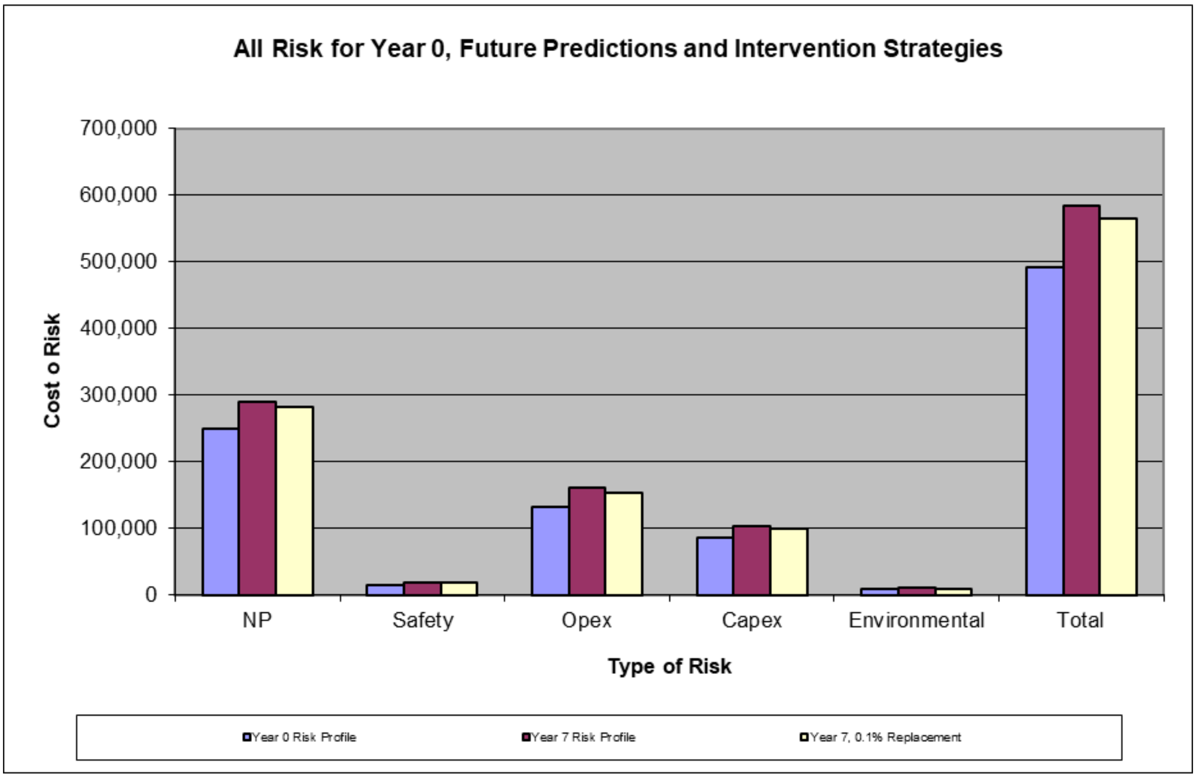
If asset replacement is deferred until 2031 (Year 7) the CBRM model of the health index profile does not change significantly, as indicated in Figure 4-66, and this reflects the age profile of the asset class.

Figure 4-66 Year 7 Health Index Profile, Gas Switches



The total risk of the risk for all failure scenarios at Year 7 is calculated to be $492k with a predicted failure rate of 27 minor and one major failure per annum. It can be seen in Figure 4-67 below that the risk profile does not change much over the 7 years as there are very few major failures predicted in this period.

Figure 4-67: Risk Profile for Year 0 & Year 7, Gas Switches



In order to maintain the risk associated with the operation of these assets at current (year 0) levels this strategy allows for the replacement of approximately 1 gas switch per annum over the course of the next 7 years or a 0.1% replacement rate per annum as a result of asset failure. The majority of gas switch installations included in this strategy are to facilitate the retirement of air break switches.

4.7.4 RISK

4.7.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. An asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). The results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is also used to rank the importance of dissimilar sub-asset classes (e.g., transformers and buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

The overhead HV switchgear sub-asset class has an asset criticality score of AC1 (Low) due to the consequence rating being minor.

Similarly, LV switchgear has a low criticality score due to the minor consequence of a failure.

Overhead line switchgear impacts on the JEN overall network reliability and Service Target Performance Incentive Scheme (STPIS) via the minimisation of customer numbers off supply during an unplanned outage.

4.7.4.2 *Failure Modes*

Failure modes for this sub class include:

- Fail to operate – either open or close, for air break switches this is often due to seized, or misaligned mechanisms, faulty latching mechanism or contact system. For air break switches this includes defective handles or down rods. For manual gas switches this include SF6 gas leak and pressure dropped below the lockout threshold. For remote controllable gas switches this includes the failure of the communication or control system;
- Fail to carry load – due to deteriorated or high resistance internal components; could lead to thermal overheating and explosive failure;
- Overheating - due to high resistance external connections/components; could lead to thermal overheating and damage;
- Insulation breakdown - internally, due to contamination or lack of SF6 or externally due to insulator or bushing failures;
- Hardware mechanical failure – Includes operating mechanisms, handles and earthing connections;
- Failure due to external factors – includes animal contact and extreme weather condition; and
- Failure due to operational errors or third party – includes operator not closing and latching the switch properly and vandalism.

4.7.4.3 *Current Risks*

This section provides information about specific overhead line switchgear issues, as well as general issues. For details of the risk assessment, refer to the relevant section in JEN's Risk and Compliance Management System (OMNIA).

The following list of current and emerging network risks includes those which are for information purposes only, as well as items which require further development of inspection, maintenance or replacement programs:

- Given the age of the air break switch population and the ongoing maintenance requirements, only minor corrective maintenance will be undertaken as a result of the inspection program. In all cases wherever significant component replacement, adjustment or repair is required, the air break switch shall be replaced with a gas switch or an ACR;

- Recurring issues on 22kV air break switches include, adjustments needed as a result of incorrect installation, the early use of green timber segments in operating rods, operating handle diameters, the earthing of operating handles, brown insulators and identification plates;

- A visual inspection of gas switches is required to be carried out every 10 years. As these switches are inspected as a part of the line inspection program every 3 or 4 years and this can be undertaken from ground level, no allowance is made for additional gas switch inspection. In addition, gas switches are inspected by ENO's when they are operated to check for low gas indications;

- In late 2003, the first of a series of ABB HV isolator failures was observed with the mode of failure being cracks forming on the porcelain insulator. These cracks resulted from corrosion of the supporting pin where it was cemented into the insulator. The cracks caused the insulator to fail mechanically resulting in breakage often when the isolator was being operated. An initial survey identified and subsequently replaced 18 ABB isolators with the new standard type isolators. A project was then setup to replace these isolators which replaced all ABB isolators manufactured between 1996-1998. Current programs have replaced 207 ABB isolators since 2011, with 59 replaced between 2015 to 2017. All of the remaining ABB isolators need to be surveyed and scheduled for replacement. Asset records indicate that there are between 30 and 80 sets of isolators remaining on the network of this type. These will be scheduled for replacement in order to completely remove this population from the network;

- From approximately 2002 to 2009 the make of HV isolator used was a non-latched NGK model. In 2009 a number of outages were attributed to non-latched isolators 'falling' open. Upon investigation it was suspected that bolts that had not been sufficiently tightened during manufacturing were allowing the isolators to be closed incorrectly (too much lateral movement in the arm). The manufacturer, NGK, changed their isolator design to one with a latching mechanism when closing and is now standard design. Monitoring of faults attributed to isolators will continue to identify whether pro-active measures are warranted;

- Manual handing issues are always present in the operation of overhead switches, in particular switches that are operated by an operating rod and handle from ground level. Older switches can become stiff and difficult to operate. Safe operating procedures and correct manual handing practices are mandatory for operating any switch and adherence to these practices mitigates potential health and safety risks. The increased use of manual gas switches also improves the conditions for field staff required to operate a switch;

- All gas insulated switches are currently fitted with gas pressure indication in the form of low pressure lockouts. Some early versions did not have this indication system and these units have been proactively retired; and

- Iljin gas insulated load break switches have been found to suffer from galvanic corrosion of the low gas lockout mechanism. There are 235 of these switches in service on the distribution network. A program has been implemented to inspect the condition of all of these switches. Based on the results of these inspections a prioritised program has been developed to repair or replace these switches as required.

- NGK remote controlled gas insulated load break switches with new control box model GSS100 REV2 have had three inadvertent opening of the switches without the command signal sent since the installation started in late 2021. The root cause is being investigated. There also found 27 control box batteries swelling since the installation due to the overcharge as a result of the new battery charging circuit design. The supplier recommended to install a voltage limiting cable (VLC) in series with the charging circuit to prevent overcharging the battery. The installation of VLC's and inspection/replacement of batteries are in progress and the effectiveness of the VLC is yet to be confirmed.

4.7.4.4 *Existing Controls*

The controls that are applied to this group of assets in order to maintain their performance and manage risk include the following:

- Inspection - All overhead line switchgear is inspected in conjunction with the asset line inspection program which involves a visual inspection of insulator condition, mounting hardware, operating arm and connections. For HV gas insulated switchgear, visual inspection also includes switch OPEN/CLOSE status indicators, gas pressure indictors and tank condition;
- Infra-red thermal surveys are conducted on all HV overhead feeders and associated HV switchgear on a 1-3 year cycle dependent on priorities. All LV circuits on HV poles are also surveyed. Any identified defects are prioritised and maintained accordingly;
- Functional checks – all manually operated overhead line switchgear is inspected by field operators before it is operated. Any defects or malfunctions are reported, and maintenance notifications created. Defective plant will be CRO (caution regarding operation) tagged;
- Routine maintenance - the control and radio communications equipment in remote controllable gas switches is maintained at 8 yearly intervals and battery replacements occur is at 4 yearly intervals;
- Future network development – JEN has standardised the installation of remote controlled switches (RCS) and ACR's for all overhead line switching installations. This will facilitate the automation of the distribution network. HV isolators are no longer installed in new installations and are only used for maintenance and fault repair of existing installations; and
- Proactive replacement – JEN has identified certain HV switches that require proactive replacement as highlighted in Section 4.7.4.3 Current Risk (Issues).
    - Vertically or horizontally mounted Taplin two insulators type switches (all 1977) with 25mm drive shafts are prone to twist and this results in the three phases of the switches not operating together. These shall be identified and removed or replaced with a gas switch where operationally required;
    - Due to increasing problems with insulators breaking, any vertically or horizontally mounted Taplin D209 switches shall be identified and where required scheduled for replacement with a gas switch;
    - ABB manual gas switches have no gas pressure indication, and these have been retired;
    - A program has been established to replace CRO tagged switches. When they are identified they are scheduled for replacement or minor maintenance.

4.7.4.5 *Future Risks*

Single phase switching of any network segment with a significant length of three phase underground cable disrupts the normally balanced and self-cancelling capacitance in the cable resulting in capacitive current flow to earth. With the increasing utilisation of underground cables in JEN, the potential for single phase switching to create capacitive current flow of sufficient capacity to trip the sensitive earth fault protection on a feeder is substantial and potentially growing. This in turn can result in the unplanned interruption of customer supplies. JEN has ceased the installation of new HV isolators in favour of remote control switches (RCS) or ACR's on the distribution network. This will ensure the progressive movement away from single-phase switching in JEN however, care will still need to be taken with the legacy installations of HV isolators and the increasing installation of underground cable.

4.7.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy covers time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance.

4.7.5.1 *Creation*

The various assets within the overhead line switchgear group are typically purchased under period contracts and installed in accordance with the standards described in the distribution construction manual and specification requirements.

They are deployed to sectionalise the distribution network in accordance with the principals set out in the JEN Planning Manual – JEN MA 0010 and to facilitate the remote control of the network. Consequently, they are installed in conjunction with projects that involve load growth and also as a result of projects aimed at the improvement or maintenance of network reliability performance.

As part of JEN's strategy, as it relates to the automation and remote control of the HV network, as from 2022 only remote controllable switches (RCS) or ACR's will be installed as switching devices on the HV overhead distribution network. This is to apply to all future HV overhead switch installations.

Proposals for future improvements in this document will be incorporated in the contents of future plant specifications. Refer to Section 4.7.3.1 (Performance-Requirements) for overhead line switchgear design and construction standards.

4.7.5.2 *Asset Operation and Maintenance*

There are four (4) life cycle management strategies applied to the operation and maintenance of overhead line switchgear:

- Asset Inspection and Condition Monitoring;
- Preventative Maintenance;
- Reactive and Corrective Maintenance; and
- Run to Failure.

The preferred maintenance strategy for overhead line switchgear is one driven by condition monitoring via the various inspection programs and work practices together with reactive and corrective maintenance activities.

The strategy applied to the lifecycle management of LV overhead switchgear is a run to failure strategy. The consequence of failure of these assets is minor.

4.7.5.2.1 Asset Inspection and Condition Monitoring

All overhead line switchgear is inspected in conjunction with the asset line inspection program which involves a visual inspection of insulator condition, mounting hardware, operating arm and connections.

For HV gas insulated switchgear, visual inspection also includes switch OPEN/CLOSE status indicators and tank condition. Furthermore, for remote controllable gas switches, the control box and radio communications equipment are monitored via SCADA and also checked at 4 yearly intervals as part of the battery replacement program.

Pole mounted switches for non-pole type substations (ground type substations) are included in the asset line inspection program. Non-pole type switchgear is included in the non-pole type substation policy and substation inspection program.

In addition to the 3-4 yearly visual inspection, HV overhead line switchgear is included in the 1-2 and 3 yearly thermal survey of overhead lines. Any defects detected are programmed for repair.

Functional checks and inspections are carried out on all manually operated overhead line switchgear by field operators before it is operated. Any defects or malfunctions observed or detected are reported and maintenance notifications created. Defective plant is CRO (caution regarding operation) tagged.

These programs help identify and resolve issues with the overhead line switch population to prevent in service failures.

Individual switches or particular families of switches which are identified as having a current or emerging issue may be placed on a more frequent inspection cycle or included in a routine maintenance program to ensure the switch is maintained in a safe and reliable condition.

Remote controllable switches have the ability to report asset condition indicators via SCADA. Condition indicators that can be remotely monitored include low gas alarms, AC supply alarms, DC battery alarms and Comms Fail alarms.

4.7.5.2.2 Preventive Maintenance

The necessity for maintenance activities on overhead line switchgear is primarily determined by the results of the scheduled inspections and the priority assigned to any defects found. If no switchgear defects are detected, then no maintenance is necessary.

Preventive maintenance is applied to remote controllable switches which are maintained every eight years to check the functionality and integrity of the control box and the switch mechanism. The control box battery is scheduled for replacement every four years.

Preventive maintenance is not considered cost effective for disconnectors, isolators and LV switchgear and therefore only corrective maintenance is to be performed on these assets.

4.7.5.2.3 Reactive And Corrective Maintenance

Reactive and corrective maintenance is conducted when asset inspections and checks identify defects or when in service failures occur.

The scope of reactive and corrective tasks undertaken on HV air break switchgear and disconnectors is limited to minor maintenance. In all cases where the need for major maintenance is identified then JEN’s policy is to replace the switch with a gas switch or remove the switch altogether.

- Minor Maintenance
    - Items classified as ‘Minor Maintenance’ can be performed without removing the switch from the pole or making significant adjustments to the switch whilst remaining mounted to the pole.
    - In possum and bird prone areas, an economic assessment shall be conducted to assess the benefit of a gas switch to minimise the frequency of animal contacts. If a positive economic assessment is achieved, a gas switch shall be installed.
- Major Maintenance
    - Items classified as ‘Major Maintenance’ generally require the switch to be removed from the pole in order to complete the maintenance. Typical work required will include; replacing insulators, main contacts & moving blades and fitting of expulsion interrupters.

- If it is identified that major maintenance is required on a switch, the switch shall either be retired or replaced with a gas switch (refer to JEN GU 0010 - JEN Planned & Opportunistic Maintenance & Workmanship Guideline for more information).

Gas switches are sealed, and no maintenance is performed on the switch itself. If there are mechanical issues, the switch is replaced. Remote controllable gas switches are monitored via the Supervisory Control and Data Acquisition (SCADA) system and the equipment is maintained as required.

HV isolators can be removed and or replaced due to in service failure described by the following damage causes:

- Failed mechanical integrity (mechanical failure/deterioration);
- Failed required mechanical support;
- Failed to carry load (electrical overload);
- Failed to close;
- Failed to maintain physical clearances; and
- Failed to open.

No maintenance is undertaken on LV overhead switchgear. In all cases when defects are detected the switching device is to be replaced.

4.7.5.3 *Asset Replacement*

4.7.5.3.1 Proactive Replacement

Proactive replacement of overhead line switchgear will generally take place as a result of failure of a family, type or model of switch which may present significant risk to network reliability or safety. For example, a family of ABB isolators manufactured between 1994 and 2000 and installed on the JEN suffered in service failures when being operated due to a design fault. This posed a risk to personnel when the isolator was being operated so a program was implemented to replace the entire family of isolators.

It is proposed that a prioritised replacement program for air-break switches commence targeting the switch types listed above in section 4.7.4.3. The proposed program would replace 25 air-break switches per annum.

4.7.5.3.2 Proactive Retirement

Proactive retirement of overhead switchgear is not common but can occur as a result of network augmentation. When switches are left in inappropriate positions due to the reconfiguration of the network then they may be proactively retired. Refer to JEN GU 0010 - JEN Planned & Opportunistic Maintenance & Workmanship Guideline for more information.

4.7.5.3.3 Condition Based Replacement

Condition based replacement is JEN's preferred asset replacement strategy as it ensures assets are replaced at a time in their life cycle that ensure maximum utilisation. All overhead line switchgear is replaced based on condition. The replacement activity is driven by the asset inspection programs and JEN's policies as they relate to the maintenance of obsolete and air break type switches and disconnectors.

The replacement of LV overhead switchgear is based on condition and reactive replacement as a result of in-service failure. Currently approximately 1% of the population or 150 units are replaced annually. In addition, these assets are replaced as part of the pole and pole top replacement programs.

4.7.5.3.4 Overhead Line Switchgear - Forecast Replacement Volumes

As identified in this strategy, a number of projects have been created to ensure the maintenance of network performance, and also address JEN's compliance requirements.

Table 4-58 lists the forecast replacement volumes for overhead line switchgear from 2025 to 2031.

Table 4-58: Forecast Replacement Volumes - Overhead Line Switchgear

Unique ID	Service Code	Overhead Line Switchgear	Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A144	RHG	Gas Switch Replacement	8	-	12	26	26	26	26
A285	RHG	Replace ILJIN and HV overhead GFB switches	-	-	38	-	30	62	62
A147	RHH	HV Isolators (set)	43	59	68	68	68	68	68
A900	RHJ	HV Isolators (single)	-	-	10	10	10	10	10
A149	RHL	LV Isolators (set)	122	146	150	150	150	150	150
A149	RHL	LV Isolators (single)	56	59	58	58	57	58	58

4.7.5.4 *Asset Disposal*

Disposal of all replaced or retired gas switchgear shall be in accordance with JAM PR 0060 WI 16 – SF6 Gas – Identification, Storage, Handling and Disposal.

All other assets shall be disposed of in accordance with JEM PO 1600 – Scrap Material Policy.

4.7.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.7.5.6 *Spares*

As part of the criticality assessment consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following the Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). It was determined that adequate spares are maintained at Tullamarine depot.

Note: All arc-chute switches recovered from concrete poles and/or as a result of the removal of unnecessary switches from the network are not to be reused or refurbished.

4.7.6 INFORMATION

The Information required to support asset strategies, performance and risks is recorded in SAP, the GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determine the information required to manage and operate an Asset Class.

The Electricity Distribution ACS facilitates the safe, efficient and reliable delivery of electricity to JEN's customers.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives (Table 4-59).

Table 4-59: Overhead Line Switchgear Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-60 identifies the current and future information requirements needed to support the Asset Class's critical decisions and their value to the Asset Class.

Table 4-60: Overhead Line Switchgear Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Overhead line switchgear acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied overhead line switchgear and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Type - Operating voltage - Connection type - Switch No. - Operating state - Normal state - Switch location - Ganged - Remotely controllable - Design Environment - Insulation type - Earthed - Mass of SF6 - Manufacturer - Load breaking - Pole No. - Feeder - Date Installed • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Switch rating • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-61 provides the information initiatives required to provide the future information requirements identified in Table 4-60. Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-61: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.8 LV OVERHEAD SERVICES SUB-ASSET CLASS

4.8.1 INTRODUCTION

An LV overhead service is defined as the terminating span that connects the distribution low voltage overhead mains (JEN asset) to the point of supply (customer's asset), including the associated hardware such as termination clamps, brackets, and connectors. Whilst low voltage overhead services are singularly one of the least expensive items on the distribution system; as an asset class the volume and value is significant.

There are in excess of 158,000 overhead services owned and operated by JEN and 97% of these are of three main types:

- Neutral Screened;
- Grey twisted PVC; and
- LV ABC.

Large scale batch replacements of service cables result in minimal gains in SAIDI, etc. as most low voltage overhead service faults result in single customer short duration outage.

4.8.2 ASSET PROFILE

4.8.2.1 *Life Expectancy*

As prescribed in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for an overhead service line is 40 years.

The review of asset useful lives considers asset lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered.

4.8.2.2 *Age Profile*

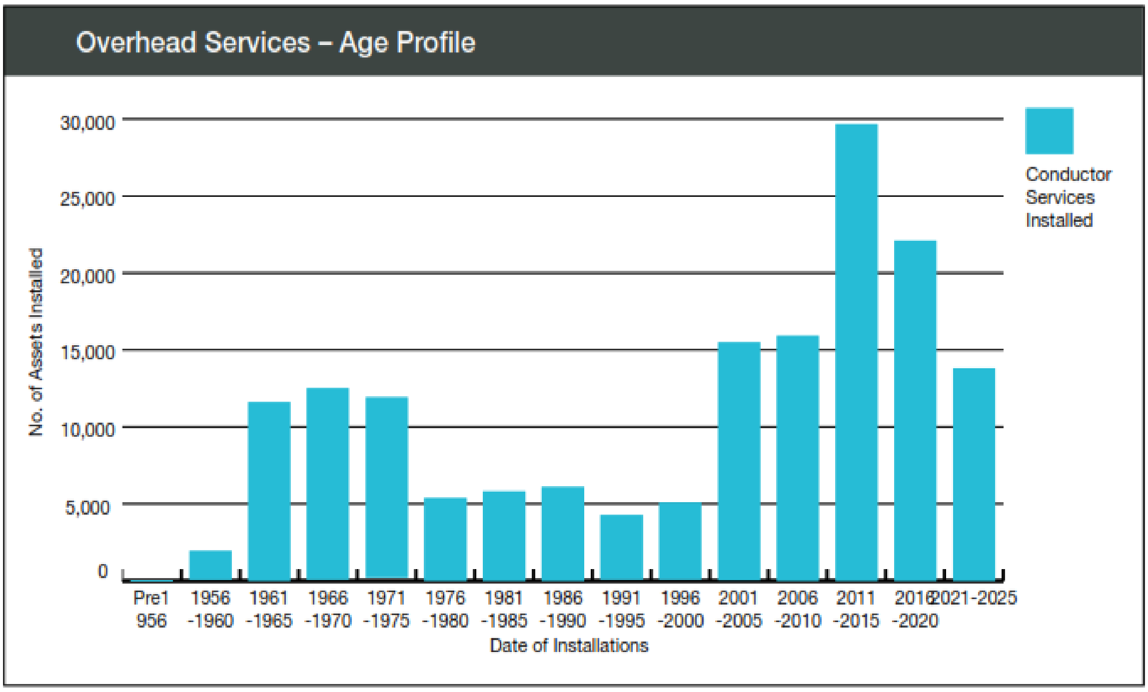
The LV overhead service age profile encompasses a broad timespan, with some of the LV services dating back to the 1930's. LV overhead services installed on JEN are listed in the Table 4-62.

Table 4-62 LV Overhead Service Population by Type

Service Type	First Used	Last Used	Population	Percentage of Overhead Population
Bare/Open Wire	1930's	1990's	1,215	0.77%
Red Lead	1940's	1960's	33	0.02%
Neutral Screened	1960's	1974	37,621	23.70%
Twisted Wire	1976	1989	14,820	9.33%
ABC	1989	Present	102,147	64.34%
Total			**158,767**	**100.00%**

Figure 4-68 below indicates the age profile of the LV Overhead Service population.

Figure 4-68: LV Overhead Services - Age Profile



4.8.2.3 *Utilisation*

Overhead services are provided to service single phase, two phase and three phase customer installations. Current overhead service lines range in capacity from 80 ampere single phase to 250 ampere three phase. They are limited to one span length (approximately 20m maximum) and normally terminate on the customers premises, but they can terminate on a Private Overhead Electric Line (POEL).

Traditionally they provided energy to a customer's installation but today they also facilitate the reverse flow of energy from a customers embedded generation system to the grid.

4.8.3 PERFORMANCE

4.8.3.1 *Requirements*

The Electricity Safety (Management) Regulations 2019 require that JEN comply with its internal technical standards (JEN's ESMS). JEN's internal standards reflect the requirements of the Electricity Safety (Network Assets) Regulations 1999. JEN's network assets have been designed, constructed and are maintained in accordance with these regulations. In addition, JEN has conducted a Formal Safety Assessment as part of its Electricity Safety Management Scheme (ESMS). This included a risk assessment of the adequacy of JEN's current internal technical standards.

JEN uses internal construction standards when building LV services. These are prescribed in the "Distribution Construction Manual". These standards include design parameters which address areas including clearances and equipment types.

All LV ABC overhead service cable shall comply with the requirements of:

- AS/NZS 3560.1 – Electric Cables – Cross-linked polyethylene insulated – Aerial bundled – For working voltages up to and including 0.6/1kV – Aluminium conductors; and

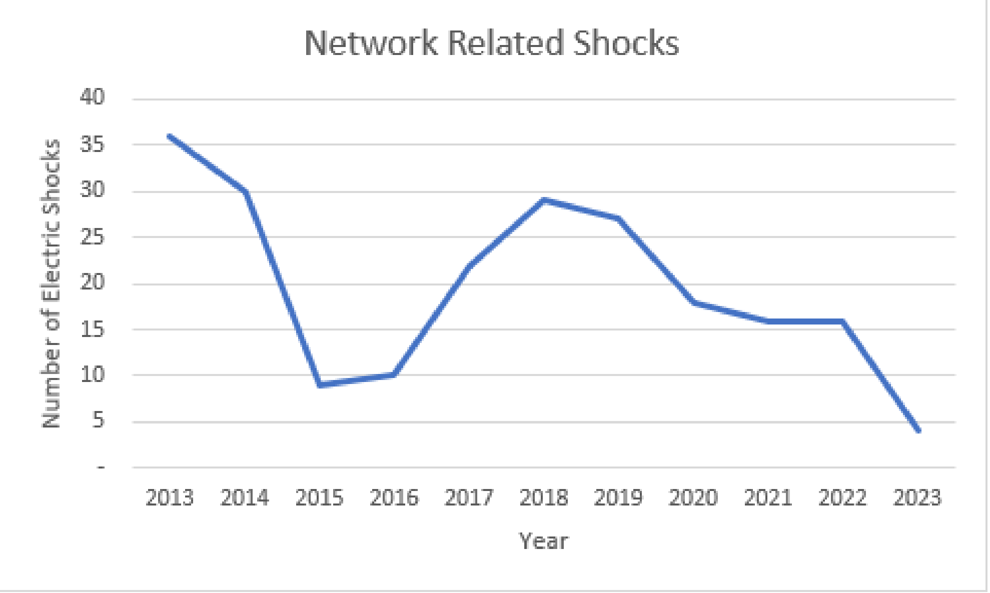
- JEN's Technical Specification for Overhead Conductors and Underground Cables.

4.8.3.2 *Assessment*

The performance measures for LV overhead services are based on shocks, fire starts, height non-conformance and NST failures.

Figure 4-69 below shows the number of reported electrical shocks related to JEN assets in that calendar year. When this data is examined over a twenty year period the trend line is flat however, in recent years, there is a decreasing trend in the number of reported electrical shocks. These are typically minor shocks such as tingles from taps. This is monitored using the JEN Analytics application. This application proactively monitors the impedance of services (wherever an AMI meter is installed) and has the potential to identify and thus facilitate the repair of defective neutrals before shock hazards materialise.

Figure 4-69 Electrical Shocks due to Network Assets



4.8.4 RISK

4.8.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. An asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is used to rank importance of dissimilar sub-asset classes (e.g., transformers and buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

The overhead service line sub-asset class has an asset criticality score of AC4 (High) due health and safety risk to staff and the general public caused by electrical shocks associated with broken or high impedance neutrals.

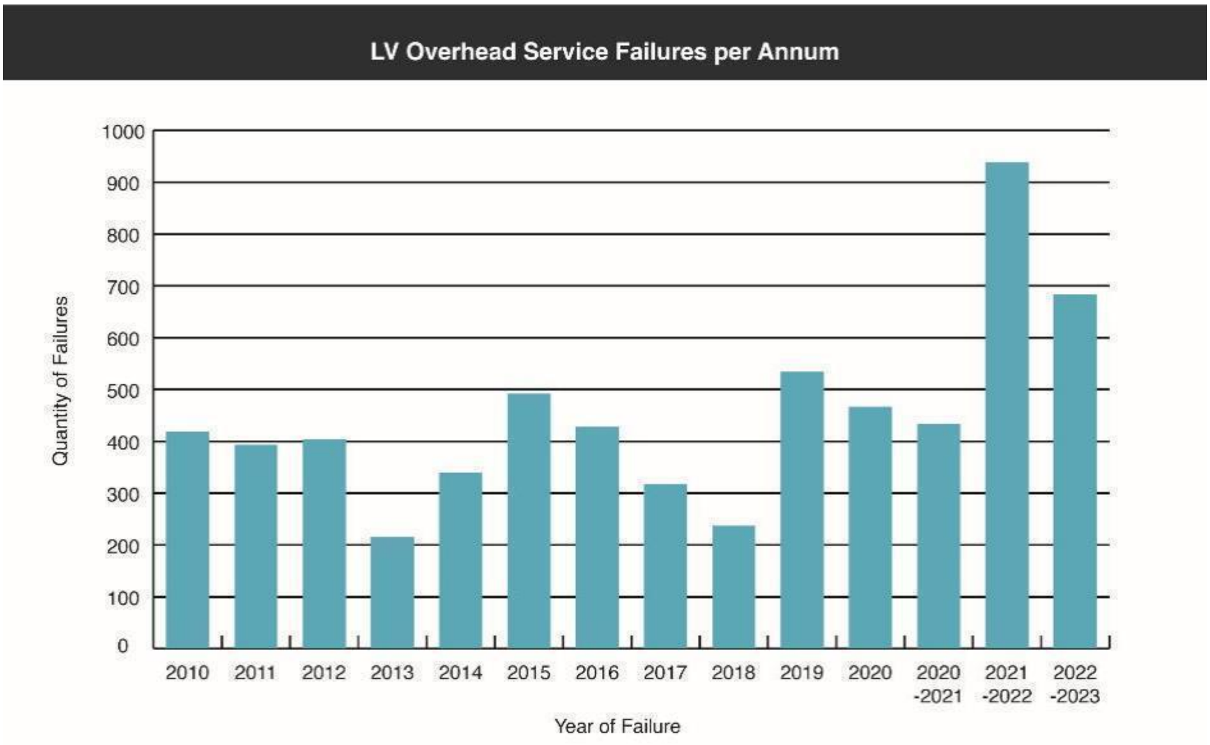
4.8.4.2 *Failure Modes*

Failure modes for the sub class include:

- Electrical failure of cable insulation material and joints/terminations;
- Corrosion of neutral screen causing high resistance or open circuited neutrals and lack of earth bonding;
- Mechanical failure of cable and or anchoring fixtures due to deterioration, and physical impacts; and
- Cable damage associated with abrasion of the insulation by vegetation.

Figure 4-70 below indicates LV Overhead Service failure volumes by year since 2010.

Figure 4-70 LV Overhead Service Failures by Cause Category



The dominant mechanism which may lead to an electrical shock is failure of the service neutral, customer installation neutral or neutral connections, to the extent that the neutral impedance is unacceptably high. When the neutral impedance becomes high, the parallel return path for neutral currents provided by the customers' installation earth connection becomes important. If this earth impedance is also high, then as current flows in the installation, a voltage rise will occur, and it is possible for the potential of the metalwork bonded to the earth system to also rise relative to the general mass of the earth.

When there is a potential rise on bonded metalwork there is the risk of electrical shock to persons who contact the metalwork and conducting earthed material simultaneously. Typically, this occurs in showers where wet conditions and contact with both live taps and the waste pipe allows a small current to flow.

The failure rates are low in relation to the number of LV overhead services installed. This indicates that the proactive service replacement programs appear to be having a positive effect on the performance of this asset class. However, failures continue to occur across the service population and ongoing replacement is required.

4.8.4.3 *Current Risks*

For details of the risk assessment, refer to relevant section in JEN's Compliance and Risk System (OMNIA).

The major risk associated with LV overhead services and terminations is electrical shocks that result from damaged service neutral conductors or connections.

Current risks include:

- Investigations into reports of minor electrical shocks continue to identify failure of neutral screened services as a contributor to the incident. Of the incidents allegedly caused by network service assets, about 66% are attributable to a failure in a neutral screened service. Aluminium neutral screened cable is particularly problematic. It is not possible to distinguish between aluminium and copper neutral screened cables externally. The remainder of incidents are made up of other non-preferred services.
- The risk of electric shock associated with the inadvertent contact of the active service conductor with the supporting structures at the customer end. There have been a small number of incidents that have caused raiser brackets and building spouting to be made live due to damage to the insulation on the active conductor and contact with these structures.
- Due to the fire hazard associated with Private Overhead Electric Lines (POEL) in the HBRA, the Victorian Service and Installation Rules (VSIR) requires that where "a POEL has to be substantially re-constructed in a hazardous bushfire risk area the line is to be placed underground". Hence all POEL's in the HBRA will eventually be placed underground. As a further encouragement, customers within the HBRA and LBRA are offered the free installation of a pit at their boundary to facilitate the undergrounding of their POEL.
- A Safety Gram from Energex highlighted that some Low Voltage XLPE service cables installed during 2005 and 2006 (LV ABC) have experienced insulation failure on the top surface of the cable through UV degradation. The insulation failures have originated from batches of 25mm^2 Aerial XLPE service cable imported from an overseas factory. XLPE service cable from the same manufacturer was received during the same timeframe and installed on JEN. No similar premature failure of XLPE has been observed. Monitoring of this situation continues via the line inspection program.

4.8.4.4 *Existing Controls*

The existing controls that are intended to mitigate the risks associated with the operation of overhead service lines includes the following:

- All LV overhead services are visually inspected for electrical and mechanical integrity as part of the standard asset inspection program, every 3 years in the HBRA and every 4 years in the LBRA. Refer to the Asset Inspection Manual, Chapter 12 - JEN MA 0500. This is to ensure that the service line remains clear of surrounding supporting structures, that strain clamps are correctly attached and supported and the integrity of the insulation on the service cable is maintained;
- The JEN Analytics Application (JENA) uses data from, and technology installed in AMI meters to constantly monitor the impedance of service lines and cables. When service impedances are detected that exceed expected levels then an alert is generated, and the service is inspected by a faults crew to determine if a problem exists or is developing. In this way defects associated with service neutrals are detected and addressed proactively.
- The Neutral Integrity Testing program requires the testing of all service neutral impedances that are not monitored by the JENA application on a ten year cycle. This covers sites with legacy meters, unmetered supplies and AMI meters with minimal loads.

- The non-preferred service replacement program aims to replace obsolete or non-preferred services over the next 13 years (to be completed by 2035) at a rate of approximately 4,000 services per year. This replacement rate is further increased by other drivers of service replacements such as faults.

4.8.4.5 *Future Risks and improvements*

Improvements to the management of LV overhead services:

- The JENA application has the potential to facilitate a change to the life cycle management practices applied to this group of assets. The potential exists to move away from proactive replacement programs that target particular families of non-preferred services to a strategy for the management of LV services that is based on the constant condition monitoring of the service impedance. This would mean that service replacement would be based on the service impedance (neutral integrity) as assessed by the JENA application and or the results of the line inspection program.

4.8.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy involves condition monitoring, time based inspections, condition based maintenance and replacement, proactive replacement as well as in-service failure based reactive maintenance.

4.8.5.1 *Creation*

LV overhead services are created and installed in response to requests for new connections from network customers.

4.8.5.2 *Asset Operation and Maintenance*

There are three (3) life cycle management strategies applied to the operation and maintenance of LV overhead services:

- Asset Inspection and condition monitoring;
- Preventative Maintenance; and
- Reactive and Corrective Maintenance.

4.8.5.2.1 Asset Inspection and Condition Monitoring

All LV overhead services are visually inspected for electrical and mechanical integrity as part of the standard asset inspection program, every 3 years in the HBRA and every 4 years in the LBRA. Refer to JEN MA 0500 – Asset Inspection Manual for details. Visual inspections of overhead services are also conducted as part of vegetation management, height measurements and opportunistically during maintenance. The routine inspection and testing of services is mandated by the Electricity Safety (Bushfire Mitigation) Regulations 2013. Defective services identified during inspection and testing are replaced.

In addition, Neutral Integrity Tests are required every 10 years if the impedance of the service is not monitored by the JENA application.

Asset Inspection activities include:

- Check service integrity from the pole end to the premise end (e.g., tree damage, UV degradation, broken/wrong fittings, conductor clearance to supporting brackets, etc);
- Low voltage overhead services shall be visually inspected from ground level during any fault investigation;
- Service Clearance Inspections as specified in the JEN Electricity Safety Management Scheme (ESMS) for low services; and
- Neutral Integrity testing of the service with a Neutral & Supply Tester at the supply metering equipment.

4.8.5.2.1.1 Neutral Supply Test (NST) Program

JEN has conducted a Formal Safety Assessment as part of its Electricity Safety Management Scheme (ESMS) submission to Energy Safe Victoria (ESV) which incorporated a risk assessment of the adequacy of JEN's current internal technical standards, in particular the NST program which requires that all overhead services have a neutral to earth resistance of less than 1Ω and that this must be verified at least once every 10 years. The ESV has reviewed and approved JEN's ESMS which includes the NST program.

The initial NST program was completed at the end of 2009. The program has been suspended for the duration of the advanced interval metering (AMI) roll out because the obligation for the 10 year period (2010 to 2019) will be met by the AMI program with respect to resistance testing of all service neutrals.

4.8.5.2.1.2 Metering Data Analytics (JEN Analytics Application)

JEN has implemented a "supply monitoring" project which involves the collection of time synchronised data (voltage, current and power factor) from every AMI meter at 5-minute intervals. In 2017 the software system for the acquisition of 5-minute data was commissioned. A hardware platform for running advanced data analytics has been installed and a number of data analytic algorithms have been developed as follows:

- Supply neutral integrity monitoring – provides round-the-clock monitoring of the integrity of the service line. High impedance connections on the service line/cable can indicate the presence of a health & safety hazard for individual customers or could indicate upstream problems with the potential to impact the wider area;
- Customer phase connection identification – is used to identify the phase connection of low voltage customers based on voltage correlation studies. Correct phase identification allows JEN to develop an accurate LV network model which can be used to balance loads between phases, improve asset utilisation and improve quality of supply to its customers; and
- Proactive quality of supply monitoring – the time series voltage data collected can be used to assist with voltage complaint investigations and general improvements to supply quality.

In 2019 the data analytic algorithms were verified by site measurement and this was followed by operational implementation.

Neutral integrity testing (NST) will continue on a 10 year cycle (from 2019) for customers who do not have AMI metering.

4.8.5.2.2 Proactive Maintenance

LV overhead services are replaced according to ELE-999-GL-EL-003, JEN - Overhead Service Line Procedural Standard.

Replacement of an LV overhead service will occur in the following circumstances:

- Proactive replacement programs in poor performing suburbs based on the number of shocks and service rectifications;
- Failure of or damage to a service line or service termination;
- When a maintenance notification has been created following inspection and testing as prescribed by the Electricity Safety (Installations) Regulations 2009;
- In conjunction with asset replacement or project work involving pole or pole top assembly replacement or conductor replacement, see JEN GU 0010 – JEN Planned and Opportunistic Maintenance and Workmanship Guidelines; and
- Where re-sagging of the service line does not achieve minimum regulated heights as prescribed by the Electricity Safety (Installations) Regulations 2009. See ELE-999-GL-EL-003 JEN - Overhead Service Line Procedural Standard

Non-preferred low voltage overhead service cable types include:

- Red lead;
- Open wire for residential supply;
- Aluminium neutral screen;
- Rubber (neoprene) insulated copper neutral screen;
- Flat type (non-twisted) PVC insulated services with 10mm^2 aluminium conductor; and
- Grey twisted, PVC insulated 25mm^2 and 35mm^2 aluminium service cable

Note: Three-phase open wire commercial or industrial services are acceptable services and assessed for replacement based on condition.

4.8.5.2.3 Reactive and Corrective Maintenance

All defective LV overhead services shall be replaced. Service lines are not repaired or maintained. LV overhead service conductor (of any construction type) shall not have a straight joint or repair made mid-span.

Undersized Neutrals, refer to section 1.3.5.3

4.8.5.3 *Asset Replacement*

Overhead services are replaced based on condition. All service defects result in the replacement of the service line.

Proactive replacement programs for LV overhead services lines involve the identification and replacement of all non-preferred services in a targeted area based on asset performance. All new LV overhead services lines are constructed using Aerial Bundle Cable (LV ABC), typically either 25mm^2 or 35mm^2.

4.8.5.3.1 LV Overhead Service Lines - Forecast Replacement Volumes

As indicated in this strategy, a number of projects have been identified to ensure that we maintain network performance, and also address our compliance requirements.

Table 4-63 lists the forecast replacement volumes for LV overhead services from 2025 to 2031.

Table 4-63: LV Overhead Service Line - Forecast Replacement Volumes

Unique ID	Service Code	LV Overhead Services	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A152	RMF	Service Fault Replacement	607	607	900	900	900	900	900
A153	RMJ	Replace Service and Alter Terminations	408	386	380	380	380	380	380
A155	RML	Install Disconnect Device	50	126	212	212	212	142	65
A156	RMP	Replace Services – Planned	764	745	541	745	745	745	745
A157	RMP	Service Rectification Program (Non-Preferred Service)	2,169	2260	5519	5260	4000	4000	4000

4.8.5.4 *Asset Disposal*

LV overhead services are typically not repaired but instead are replaced as required.

LV overhead services should be disposed of in accordance with JEM PO 1600 – Scrap Materials Policy.

4.8.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.8.5.6 *Spares*

As part of criticality assessment consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (JEM AM PR 0015). Adequate spares are maintained at Tullamarine depot and stock holdings are managed by the Service and Projects team.

LV overhead services parts and components are stocked in the stores and on the faults trucks and replenished as required.

4.8.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level The ACS provides the context for and determine the information required to manage and operate an Asset Class.

The Information required to support asset strategies, performance and risks is recorded in SAP, the GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

From these business objectives, it is possible to identify at a high-level the content of the business information systems' required to support these objectives (Table 4-64).

Table 4-64: LV Overhead Services Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-65 identifies the current and future information requirements to support the Asset Class critical decisions and their value to the Asset Class.

Table 4-65: LV Overhead Services Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
LV overhead service acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied service conductor and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Usage - Phase Conductor Material - Phase Cross Sectional Area - Neutral Cross Section Area - Construction Type - Termination Type - No of Wires - Computed Length - Date Constructed - Date Removed - Circuit - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Breakaway device and date installed • Phase Colour • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-66 provides the information initiatives required to provide the future information requirements identified in Table 4-65. Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-66: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improved Asset Attributes	Review current asset attribution fields to ensure attributes being collected are asset specific.	Medium	Appropriate and Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.9 PUBLIC LIGHTING SUB-ASSET CLASS

4.9.1 INTRODUCTION

Public lighting has long been recognised as contributing to public safety and as a road accident counter-measure by enhancing the visibility of pedestrians, vehicles, objects and hazards. To achieve this, lighting has to enable a relatively crude visual task, without the need to distinguish fine detail and colours, but by merely providing contrast.

The major road lighting system mainly caters for the motorist, whilst the minor road or residential street lighting system principally caters for pedestrians. As pedestrians move slower than vehicles, they have more time to adapt to changes in brightness, therefore requiring lower lighting levels and lower uniformity of lighting than that required by motorists.

Assets included in this sub-asset class are:

- Public lighting luminaires
- Lamps;
- Control gear and PE cells; and
- Public lighting brackets

JEN owns, operates and maintains over 77,000 public lighting luminaires across the JEN territory. JEN manages all public lighting infrastructure on behalf of public lighting customers. The two major customer groups are Municipal Councils and the State's Road Authority (VicRoads). The AER has issued an industry guideline which describes the relationship between major electricity distributors (e.g., JEN) and all public lighting customers. JEN’s technical standard, i.e., the Public Lighting Technical Standard - JEN PR 0026, describes the commonly used and JEN approved assets such as luminaires and poles. It also provides guidance for public lighting customers who wish to utilise approved non-standard public lighting poles and lanterns fitted with standard lamps and Photo Electric (PE) cells, on the public lighting system. All poles and lanterns are owned and maintained by JEN for a fee set by JEN and approved the AER. Public lighting customer are required to hold approved non-standard spares, in lieu of the additional administrative effort required by JEN to procure these assets. Public lighting customers may elect to own and maintain public light infrastructure by installing metered electricity supplies for their schemes, e.g., in parks, barbeque areas, freeways and major roads.

4.9.2 ASSET PROFILE

4.9.2.1 *Life Expectancy*

As described in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for major and non-major public lighting lanterns and public lighting support structures is as follows:

- Public Lighting Lanterns - Major Rd 20 years[7];

[7] For new lantern types such as LED types, an asset life of 20 years is applicable. For conventional street lighting lanterns such as those using MV80 lamps, the asset life is 30 years (now obselete).

- Public Lighting Lanterns - Non-major Rd 20 years[8];
- Wooden Pole LV/Street lighting – 54 years;
- Steel Pole LV/Street lighting – 35 years;
- Concrete Pole LV/Street lighting – 70 years;
- LV OH public lighting services – 40 years; and
- LV UG public lighting services – 50 years.

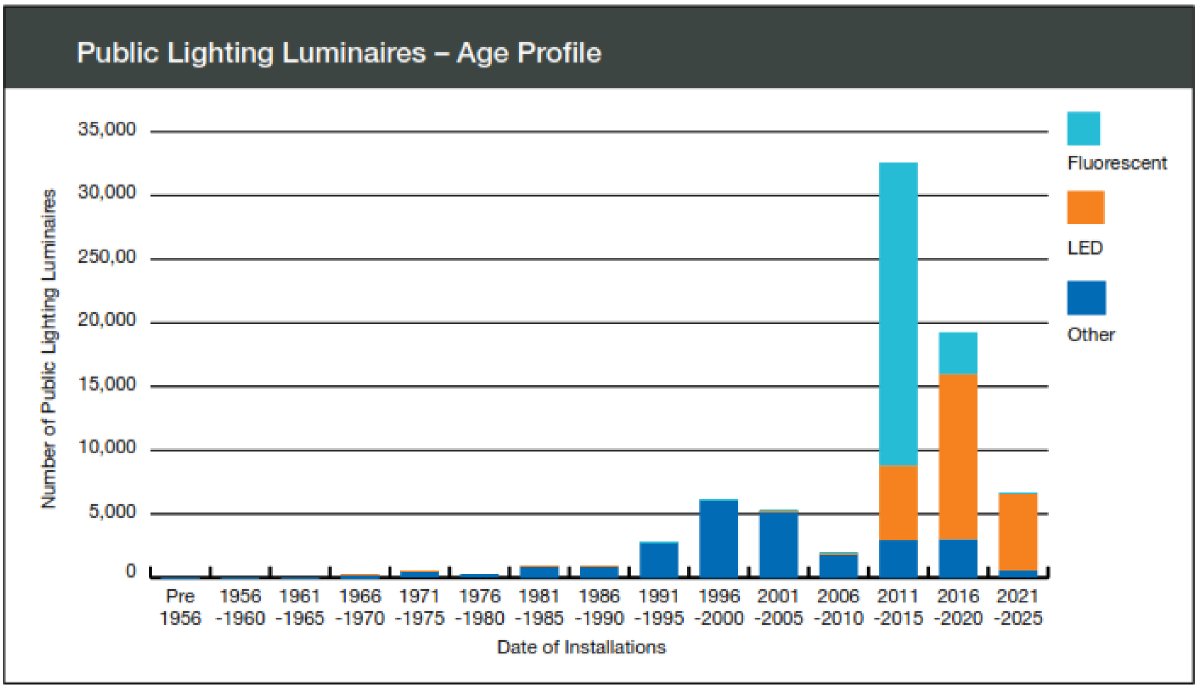
The Network Asset Useful Lives Procedure prescribes asset lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has referenced a number of reviews of asset useful lives by consulting agencies and discussions with other Electricity Distribution Businesses to inform this process.

4.9.2.2 *Age Profile*

The population of public lights can be characterised as follows:

- Public Lighting Lanterns - Major Rd; and
- Public Lighting Lanterns - Minor Rd.

Figure 4-71 Public Lighting Luminaire - Age Profile



[8] For new lantern types such as LED types, an asset life of 20 years is applicable. For conventional street lighting lanterns such as those using MV80 lamps, the asset life is 30 years (now obselete).

Table 4-67 Analysis - Public Lighting Luminaire - Age Profile

Test	Analysis/Comments
The installation of minor road luminaires has increased in the last 10 years	This is consistent with the installation of new residential estates and the widespread replacement of old technologies with new high efficiency luminaires and lamps.

4.9.2.3 *Utilisation*

The public lighting sub-asset class facilitates JEN's obligations in relation to the provision of public lighting services on major and minor roads and in public open spaces for public lighting customers. These services are provided in accordance with the requirements of the Essential Services Commission's Public Lighting Code. Each public lighting luminaire operates for approximately 4,400 hours per year to provide a safe visual environment for pedestrian and vehicular movement at night.

All public lighting asset information is recorded and maitained in the GIS system. JEN sets and charges an agreed reasonable fee approved by AER to own, operate and maintain these assets on behalf of its public lighting customers.

4.9.3 PERFORMANCE

JEN's Public Lighting Technical Standard - JEN PR 0026, contains the current standards in regards to public lighting within the JEN. This document outlines the approved standard and non-standard fittings available for use by customers within the JEN.

4.9.3.1 *Requirements*

The requirements for the perfomance of public lighting assets relate to:

- Dedicated public lighting poles and brackets; and
- Public lighting luminaires and lamps

4.9.3.1.1 Dedicated Public Lighting Poles and Brackets

The requirements for the performance of these poles and brackets includes;

- The maintenance of structural integrity under all normal operating conditions and loads;
- The security and safety of the poles and the prevention of access to live parts installed in or on the poles (particularly in relation to the security of access covers); and
- The correct operation of frangible and slip based poles (dependent upon the correct installation procedures) in the event of vehicle impact.

The requirements for all new Public Lighting Poles and Brackets are set out in the following JEN material specifications:

- Steel Public Lighting Pole Specification;
- Concrete Pole Specification; and
- Wood Poles and Logs Specification.

The requirements for the installation of these poles are set out in the Distribution Construction Manual – ELE 999 OM CN 001 and the Public Lighting Technical Standard – JEN PR 0026.

4.9.3.1.2 Major and Minor Road Lanterns

The requirements for public lighting luminaires are set out in following JEN material specifications:

- Public Lighting - Luminaires, Technical Specification;
- Public Lighting – Photo Electric Control Switches and Bases, Technical Specification; and
- Public Lighting – Electric Discharge Lamps, Technical Specification (now obsolete as these types of lamps are used for maintenance of existing installations only).

The requirements for the installation of these assets is set out in the Distribution Construction Manual – ELE 999 OM CN 001 and the Public Lighting Technical Standard – JEN PR 0026.

The requirements for these lanterns is the maintenance of the public lighting of major roads, minor roads, intersections and public open spaces in accordance with the public lighting standards and associated lighting levels. The lanterns are required to operate reliably on a daily basis with light outputs that remain in the allowable design range over the maintenance interval.

Regular main road streetlight patrols are undertaken to identify and pro-actively repair faulty main road lighting equipment thus ensuring defective lights do not remain on the system for prolonged periods of time.

Minor road lighting relies on the reporting of failed luminaires to drive repair and maintenance. Guaranteed Service Levels (GSL) dictate a response time of less than two days to repair a fault, unless otherwise agreed to between the authorised body and the member of public who reported the fault. GSL payments are only made to customers if they are an immediately neighbouring resident (Public Lighting Code clause 2.5).

Bulk relamping programs are used where appropriate to maintain the light output of public lighting luminaires at the required design levels.

The above specifications and manuals set out the performance standards to be met and the design features required of public lighting assets. The specifications reference a number of Australian Standards. Unless otherwise specified, all public lighting assets shall be designed, manufactured and tested in accordance with the following principal Australian Standards (refer to Table 4-68).

Table 4-68 Public Lighting - Relevant Australian Standards

	Title
AS 2878	Timber Classification into Strength Groups
AS 3818.1	Timber-Heavy Structural Products-Visually Graded, Part 1 General
AS 3818.11	Timber-Heavy Structural Products-Visually Graded, Part 11 Utility Poles
AS 5604	Timber – Natural Durability Ratings
AS 4680	Hot Dipped Galvanized Coatings on Ferrous Articles;
AS/NZ 1163	Cold-formed Structural Steel Hollow Sections.
AS/NZS 1158 (series)	Lighting for Roads and Public Spaces
AS/NZS 60598.1	Luminaires – Part 1 – General Requirements and Tests
JIS C 8369	Photoelectric controls for public lighting

	Title
SA/SNZ TS 1158.6	Lighting for Roads and Public Spaces
SA/SNZ TS 1158.6	Part 6: Luminaires - Performance

4.9.3.2 *Assessment*

The performance of public lighting poles is assessed via the pole and line inspection program. Routine inspection of public lighting poles is consistent with inspections carried out on power poles. The prime purpose of pole inspection is to identify defects that could potentially lead to health and safety incidents affecting the general public and JEN personnel if left unchecked. JEN has had a number of incidents of damaged and or missing pole access cover plates resulting in the potential for unauthorised access to live wires.

The correct installation of frangible poles is essential to ensure the pole behaves as it is intended in the event of a vehicle collision. Routine inspections will ensure any incorrectly installed poles are identified and rectified.

The performance of electricity distribution power poles which also support public lights is detailed within the section 4.1 Poles sub-asset Class Strategy. It documents the frequency of breakdowns and in service pole failures. It applies to poles whether they have public lighting assets attached or otherwise.

4.9.3.2.1 Metrology Auditing

On an annual basis, JEN is required by AEMO to undertake metrology audits of its public lighting data. This audit ensures that the energy consumption charged to public lighting customers from the data held in our GIS system matches the actual field inventory. The number and size of audits is dependent on previous audit results. For more information refer to the AEMO Metrology Procedure.

4.9.3.2.2 Public Lighting Performance Reporting

The monitoring and optimisation of the performance of public lights is achieved via the preparation of the following reports:

- Quarterly Public Lighting Performance Report; and
- Annual Public Lighting Performance Report.

The data included in Table 4-69 is extracted from the annual public lighting performance reports.

Table 4-69: Performance of Public Lighting from 2012 to 2022

Measure	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total lights reported out (GSL Applicable)	762	952	1,320	1,159	1,620	2,293	2,432	2,026	1,811	1,410	1,431
Total Lights reported out (Not GSL Applicable)	2,693	2,102	2,396	3,803	4,235	3,566	2,978	3,185	2,747	2,822	2,663
Total Lights reported out – All Lights	3,455	3,035	3,716	4,962	5,855	5,859	5,410	5,211	4,558	4,234	4,094
Total GSL applicable not repaired within 2 working days	9	2	20	3	1	10	8	20	3	20	10
Total Not GSL applicable not repaired within 7 working days	3	2	139	17	22	16	21	24	6	5	6
Monthly average number of days to repair – All faults	3.3	3.3	3.4	2.4	2.9	2.9	3.0	3.1	3.2	4.6	7.7

Failure rates are relatively stable. As the public lighting population transitions to LED, failure rates are expected to trend downwards. Over the coming EDPR period, replacement activites will include both routine failed asset replacement as well as the transition to LEDs.

4.9.3.2.3 Major Road Lantern Patrols

Major road lantern patrols occur three times per year as per Public Lighting Code clause 2.3.1(f).

The results of the patrols can be seen in Table 4-70 .

Table 4-70 Number of Defective Lanterns Identified During Patrol

Measure	2012	2013	2014	2015	2016	2017	2018	2019	20/20	2021	20222
Number found out	1355	1155	907	690	1108	1093	927	880	1272	810	805

Failure rates are relatively stable. As the public lighting population transitions to LED, failure rates are expected to trend downwards. Over the coming EDPR period, replacement activites will include both routine failed asset replacement as well as the transition to LEDs.

4.9.4 RISK

4.9.4.1 *Criticality*

An asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A.

The public lighting sub-asset class has an asset criticality score of AC1 (Low) due to the low cost of replacement of public lighting luminaires and lamps.

Public lighting contributes to pedestrian and vehicular safety within the JEN area through the maintenance of lighting levels on both major and minor roads and in public open space. Public lighting assets are installed in accordance with the requirements of JEN's Overhead Line Design Manual and the Distribution Construction Manual. Street lighting spacing tables derived from Australian Standard AS1158 are used to determine the maximum spacing between lanterns. This is dependent upon the type of lantern, the height of the pole and width of the road.

For minor road lighting installations an average spacing of 70 metres is required to provide sufficient lighting levels. Therefore in the event of a single minor road lantern failure, vehicular traffic and pedestrians would transition through a non-uniform lit section of road or path for approximately 140 metres. Consequently the failure of an individual lantern can be considered as having a low health and safety impact and therefore low criticality. As a whole the public lighting system performs well and is considered very reliable at a system level.

4.9.4.2 *Failure Modes*

Failure modes for this sub-asset class include:

- The light output levels of mercury vapour lamps reduce with time and eventually fall below levels prescribed by standards;
- PE cell failure occurs resulting in either the lamp not turning on or the lamp not turning off;
- Control gear failure resulting in no light output;
- Lantern failure involving a component failure such as a lens, mounting bracket or fixing point breakage or corrosion of the lantern housing;
- Pole failure at the ground line due to corrosion or vehicle impact or severe leaning due to foundation deterioration; and
- Lantern fires due to internal component failures.

There were a number of incidents of lantern fires that occurred between 2011 to 2012. These failures have been attributed to the lighting control gear in the lantern overheating due to repeated attempts to re-strike an arc in the high pressure sodium lamp. This is associated with the end of life failure mode for high presssure sodium lamps (HPS). As the lamps age the operating presure in the arc tube increases and this results in cycling where the lamp turns off due to the high arc tube pressure. The lamp then cools down and the arc tube preasure drops allowing the lamp to restrike. The lamp continues to cycle in this way.

The manufacturer of these lanterns, Sylvania is aware of the issue and JEN now specify a new requirement of power factor correction metal can type capacitors together with timed igniters that are restricted in the number of times they will attempt to re-strike an arc in the lamps to prevent any future failures of this type.

4.9.4.3 *Current Risks*

Risks associated with the management of public lighting are documented in OMNIA and reviewed regularly.

Some of these risks include:

- Live unearthed street lighting brackets on timber poles caused by control gear insulation failure;

- Steel pole ground line failure due to corrosion;
- Missing access cover plates on public lighting poles exposing live apparatus;
- The existance of redundant bare switch wire results in a safety and bushfire risk as conductors and insulators are not maintain and the conductor continues to age; and
- Redundant switchwire can be mistaken for a neutral conductor resulting in reverse polarity hazards.

4.9.4.4 *Existing Controls*

The controls in place to manage the risks associated with the management of the public lighting system include:

- A planned switchwire removal program initiated in 2011. This is planned for completion in 2024;
- Major Road public lighting patrol program;
- GSL requirements for the repair of minor road lighting;
- Bulk MV relamping program;
- Linesman Handbook and refresher training for testing and handling unearthed streetlight brackets; and
- Pole and Line Asset Inspection Program (AIM)

4.9.4.5 *Future Risks and Opportunities*

The Minamata Convention on Mercury is an international treaty designed to protect human health and the environment from human caused emissions and releases of mercury and mercury compounds. As a result of the adoption of this treaty it is no longer possible to source MV and CFL lamps. Currently T5 type fluorescent lamps are still available but it can be expected that production of these mercury vapour based lamps will also cease in the near future.

JEN currently has approximately 58,000 lights installed on the minor road network, of which about 50% are Twin T5 fluorescent type, 10% are MV and the remaining 40% are LED types. The Minamata Convention and public lighting customers are increasingly seeking alternative, more efficient lighting sources are driving the large scale replacement of existing lighting technologies with solid state lighting (SSL) sources.

JEN is currently replacing all metal halide luminaires on the public lighting system due to the difficulties being experience sourcing these lamp types. There are approximately 100 of these luminaires in service.

JEN has adopted a range of approved LED luminaires as detailed in the Public Lighting Technical Standard (JEN PR 0026) and these are to be used for all new public lighting installations and for all luminaire replacements. LED technology has superseded all existing lighting technologies with improved efficiency, quality of lighting and lifespan.

Technology involving fault detection is also being developed within PE cells which transmit data about the luminaire back to a central location.

Our approach to public lighting is customer driven. If supported by our customers, we would implement smart lighting technologies in the next regulatory period. This could be involve the implementation of related hardware and software.

4.9.5 LIFE CYCLE MANAGEMENT

The strategy applied to the life cycle management of this sub-asset class includes time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance (some degree of a run to failure strategy).

4.9.5.1 *Creation*

The JEN Public Lighting Technical Standard – JEN PR 0026 specifies the standard public lighting luminaires, lamps and poles that are approved for use on the JEN public lighting system.

In accordance with the Public Lighting code, a public lighting customer is required to provide a design brief that is consistent with the JEN Public Lighting Technical Standard for JEN to construct new public lighting assets on their behalf. JEN is responsible for the necessary design work and documentation required to translate the design brief to the construction stage. Alternatively a public lighting customer can chose a party other than JEN to prepare design documentaion but they must liaise with JEN to ensure the relevant standards are met.

Open tenders are issued to which suppliers must provide solutions aligned to the requirements of JEN PR 0026. All items are typically purchased under period contracts in accordance with the requirements of the specification.

4.9.5.2 *Asset Operation and Maintenance*

There are three (3) life cycle management strategies applied to the operation and maintenance of the public lighting system:

- Asset Inspection;
- Preventative Maintenance – This takes the form of periodic bulk re-lamping based on council areas. This is only applies to minor road lamps and is a requirement of the Public Lighting Code clause 2.3.1(c). This is consistent with the characteristic loss of light output associated with the ageing of MV lamps; and
- Corrective Maintenance - Lamps that fail outside of the periodic bulk re-lamping scheme are replaced as they fail on an ad-hoc basis. Guaranteed Service Levels drive the response time to repairs. Major road luminaries are also patrolled at least 3 times yearly in accordance with the Public Lighting Code clause 2.3.1(f) and are repaired or replaced as they are identified.

4.9.5.2.1 Asset Inspection

The inspection of public lighting assets includes the following:

4.9.5.2.1.1 Pole and lantern inspection

This occurs in accordance with the requirements of Section 6 of the Asset Inspection Manual - JEN MA 0500. This details the requirements for the inspection of steel public lighting poles, concrete poles and frangible poles. All poles are inspected to the same criteria as power poles and incorporated into the normal power pole inspection cycle, 3-yearly in HBRA and 4-yearly in LBRA.

4.9.5.2.1.2 Major Road Lantern Patrols

Routine patrols of major road lanterns are programmed to occur three times per year across the JEN. The patrols are intended to identify defective lamps or sections of lights, lanterns, poles, brackets and access cover plates, which may otherwise remain defective for prolonged periods. If damaged or missing access cover plates are found during a major road patrol, replacement access cover plates secured with “band it” straps are to be installed immediately.

4.9.5.2.1.3 Low Voltage (LV) Supply

The LV supply to most lanterns on the overhead system has been upgraded to 6mm2 Cu cables as part of the 80W MV replacement projects and no inspection of this is required. However, if there are any lanterns identified that have their LV supply via 2.5mm2 Cu cables these should be noted for replacement as part of other works or maintenance projects.

There are no known issues with LV supply from underground LV distribution systems and no specific inspection or testing is required.

4.9.5.2.1.4 Asbestos and PCBs in Public Lighting Equipment

The control gear (remote ballast boxes) associated with older major road MV lanterns can contain asbestos and PCB's. The replacement of major road MV lanterns will result in the removal of any asbestos and PCB's associated with this equipment. These are to be disposed of in accordance with JAM PR 0060 WI 04 - Disposal of Public Lighting Equipment.

4.9.5.2.1.5 Metrology Audits

Auditing to check the accuracy of the public lighting metrology is carried out in accordance with the AEMO Metrology Procedure – Part A. This random auditing of street lights is carried out to confirm the accuracy of JEN's asset record in relation to the physical inventory of public lighting assets and the billing systems. These audits are based on the inventory for each National Meter Identifier (NMI) in a randomly selected geographic area.

Any defective items identified during inspections are captured in maintenance notifications raised in SAP and are programmed for repair in a timeframe commensurate with the priority assigned to the defect.

4.9.5.2.2 Preventative Maintenance

Preventative maintenance is applied to the public lighting sub-asset class in the form of the bulk replacement of some types of lamps and their associated PE cells. This is a requirement of the Public Lighting Code, and it is designed to maintain the light output of minor road lighting systems at code levels.

The preventive maintenance regime involves a bulk re-lamping cycle of 4 years and is applied to minor road lamps only (e.g., MV, T5 fluorescent, compact fluorescent and a small quantity of HPS). Bulk Photoelectric (PE) switch changes are programmed to coincide with the bulk lamp changes to minimise costs. PE switches are to be changed every second bulk lamp cycle (8-yearly).

The indicative program for minor road bulk re-lamping over a 4 yearly cycle and the transition to LED luminaires is shown in Table 4-71 below.

Bulk re-lamping programs shall be conducted in the first half of each calendar year to ensure optimum level of lighting for the period of maximum darkness.

4.9.5.2.2.1 Optimum Preventative Maintenance Interval

Until recently the majority of public lighting lamps used by JEN fell into two broad categories, namely 80W Mercury Vapour (MV) lamps and T5 energy efficient lamps for minor road lighting and 150/250W High Pressure Sodium (HPS) lamps for major road lighting. The development of SSL technologies has changed the mix and now the only approved luminaires for all public lighting are LED types. The ageing characteristics of LED lights means that preventative maintenance programs are not required.

On the other hand the ageing characteristics of the two legacy lamp types is very different. MV and Fluorescent type lamps suffer a reduction in light output as they age that means they require replacement to maintain the performance of the lighting system at desired levels. HPS lamps on the other hand maintain their light output over the life of the lamp. For these reasons MV lamps are suited to a preventative bulk replacement program to maintain peformance whereas HPS lamps are suited to a run to failure management strategy.

The selection of the optimum re-lamping cycle for MV lamp types is based upon the maintenance of minimum lighting standards in accordance with AS1158. AS1158 stipulates that for a complying lighting system to remain compliant the light output of lamps should not fall below 70% of initial levels. Test data indicates that the lumen output of 80W MV lamps and high efficency fluorescent tubes falls below 70% after 3 to 4 years and HPS (twin arc tube) lamps past 7 years. The average life of twin arc tube HPS lamps based on manufacturer's data is 7 years.

For these reasons the bulk re-lamping of legacy major road lamps is not a requirement of the Public Lighting Code due to the superior lumen maintenance of twin arc HPS lamps. These lamps are likely to fail before their lumen output falls below 70%.

Based on the above data a 4 year re-lamping cycle for MV and fluorescent minor road lamps has been implemented to ensure the maintenance of lighting levels in accordance with AS1158. However the Minamata Covention means that MV and CFL lamps are no longer available so consequently JEN has developed a transition plan which aims to retire these obsolete luminaires at their next scheduled lamp bulk change and replace them with approved Category P LED luminaires. Bulk relamping of T5 type luminaires will continue as long as replacement lamps are available. Bulk PE cell changes are to coincide with bulk lamp changes to minimise costs. PE cells are changed every second bulk lamp change. HPS lamps are run to failure.

If our public lighting customers want to accelerate the LED rollout we will discuss options, and funding arrangements with them. We cover the approach to cost recovery in our public lighting proposal put to the Australian Energy Regulator.

4.9.5.2.3 Corrective Maintenance Regime

Corrective maintenance of the public lighting system is driven by:

- The Guaranteed Service Levels are defined under the Public Lighting Code. In accordance with these JEN is required to respond to and repair reports of faulty public lights in the nominated time frames; and
- Main Road Lighting Patrols (at least 3 times a year) are conducted to identify and drive the corrective maintenance and repair of faulty main road lighting equipment. This ensures that defective lights do not remain on the system for prolonged periods of time as per the Public Lighting Code clause 2.3.1(f).

Table 4-71 Residential Bulk Re-Lamping and LED Transition Schedule

Year	Public Lighting Customer	Light Type	Transition to LED	Lamp	Lamp & PE Cell	PE Cell
2024	Darebin	LED				x
		Non-energy efficient & Decorative	x			
	Hobsons Bay	CFL	x			
		Non-energy efficient & Decorative	x			
	Hume	T5			x	
		Non-energy efficient & Decorative	x			
	Melbourne	LED				x
		Non-energy efficient & Decorative	x			
	Moreland	LED				x

Year	Public Lighting Customer	Light Type	Transition to LED	Lamp	Lamp & PE Cell	PE Cell
		Non-energy efficient & Decorative	x			
	Yarra	T5		x		
		Non-energy efficient & Decorative	x			
2025						
2026	Brimbank	T5		x		
		Non-energy efficient & Decorative	x			
	Moonee Valley	T5		x		
		Non-energy efficient & Decorative	x			
2027	Banyule	T5		x		
		Non-energy efficient & Decorative	x			
	Macedon Ranges	Non-energy efficient & Decorative	x			
	Maribyrnong	T5		x		
		Non-energy efficient & Decorative	x			
	Melton	T5		x		
		Non-energy efficient & Decorative	x			
	Whittlesea	Non-energy efficient & Decorative	x			
2028	Darebin	LED				
	Hobsons Bay	LED				
	Hume	T5		x		
		LED				
	Melbourne	LED				
	Moreland	LED				
	Yarra	T5		x		
		LED				

This list will evolve over the next few years as a result of the transition from MV and CFL luminaires to LED luminaires to include the preventative maintenance requirements of the new LED luminaires. This is expected to be comprised of cleaning and PE cell replacement at extended intervals.

4.9.5.3 *Asset Replacement*

The proposed assset replacement strategies including forecast replacement volumes and maintenance strategies are derived after consideration of the public lighting asset age profile (life expectancy/age), historical failure trends, risk profile (failure modes), the impact of the transition to LED luminaires and asset performance objectives.

Public Lighting asset replacement is being driven by changes in technology, the Minamata Convention, and the availability of new energy efficient lighting technologies. The current standard equipment suite used on the JEN has been adopted to take advantage of new technologies offering;

- Long lamp life;
- Low lamp cost;

- High light output stability; and
- High efficiency lamps.

4.9.5.3.1 Obsolete Lantern Replacements

A number of obsolete lanterns remain in service on the JEN public lighting system. In the minor road lighting category these include all luminaire types other than LED luminaires (Table 4-74). In addition there are a range of obsolete major road lighting luminaires as indicated in Table 4-73 below. These are being replaced via the transition plan and opportunistically when they fail with the current standard equivalent lantern as part of the bulk re-lamping and maintenance programs.

4.9.5.3.2 Minor Roads Mercury Vapour and CFL Luminaires

JEN is planning for the phase out (via targeted bulk replacement and the Transition Plan) of the existing population of 80W Mercury Vapour (MV80) and CFL luminaires and their replacement with an equivalent LED luminaire driven by the adoption of the Minamata Convention.

4.9.5.3.3 Replaced Asset Standards

The assets listed below are the current standards for public lighting. Also listed are the obsolete assets with their corresponding equivalent replacements.

It is common practice to change both the PE cell and lamp when only one may be defective.

4.9.5.3.3.1 Standard Lanterns

The current standard lanterns within the JEN are shown in Table 4-72 below. Each lantern is complete with integral PE switch.

Table 4-72: Standard Lanterns for JEN

Residential (Minor) Roads	Major Roads
Category P 12W -19W LED	70W .155W and 275W L1, L2, L4 LED Cat V
High Output Category P 12W – 22W LED	

4.9.5.3.3.2 Obsolete Lanterns

Table 4-73 lists the obsolete major road lanterns on the JEN public lighting system, together with the equivalent current standard replacement.

Table 4-73: Obsolete Major Road Lanterns and their Standard Replacement

Lantern	To be replaced with
250W MV and 150W HPS	L1 70W LED Cat V
400W MV and 250W HPS	L2 155W LED Cat V
400W HPS	L4 275W LED Cat V

Table 4-74: Obsolete Minor Road Lanterns and their Standard Replacement

Lantern	To be replaced with
2 x 20W Fluorescent	12W - 19 W Cat P LED
3 x 20W Fluorescent	12W - 19 W Cat P LED
50W Mercury Vapour	12W - 19 W Cat P LED
80W Mercury Vapour, 32W CFL and 2X14W T5	12W - 19 W Cat P LED
125W Mercury Vapour, 42W CFL and 2X24W T5	HO 12W – 22W Cat P LED

It is preferable that the lantern is replaced with one that is similar to the adjoining lanterns to ensure uniformity of lighting output.

4.9.5.3.3.3 Standard Poles

The current standard range of public lighting poles used by JEN are shown in Table 4-75 below. Refer to JEN PR 0026 – Public Lighting Technical Standard for further detail.

Table 4-75: Standard Poles for Major and Minor Roads

Major Road	Non-major Road
Concrete (spigot top), 10 metre/1.5kN, Ground setting (10 metre luminaire mounting height)	URD steel 7 metre/1kN, Ground setting (5.5 metre luminaire mounting height)
Concrete (spigot top), 13 metre/3 KN, Ground setting (12.5 metre luminaire mounting height)	URD steel 9 metre/1kN, Ground setting (7.5 metre luminaire mounting height)
Concrete (spigot top), 15 metre/3 KN, Ground setting (12.5 metre luminaire mounting height)	URD steel 10.8 metre/1kN, Ground setting (9 metre luminaire mounting height)
Centre hinged, 12.5 metre, plate setting	
Centre hinged, 15 metre, plate setting	

JEN is responsible for the construction and maintenance of standard public lighting poles as outlined in the Public Lighting Code and JEN PR 0026 – Public Lighting Technical Standard.

4.9.5.3.3.4 Non-Standard Poles

Public lighting customers may choose to use approved non-standard public lighting equipment in a VESI public lighting scheme. This includes poles, streetlighting brackets and luminaires. The public lighting customer is responsible for the supply of replacement parts for all approved non-standard equipment and any associated costs. This includes the supply of the non-standard equipment (pole and luminaire) both for the initial installation and for all subsequent maintenance requirements. For further details refer to Public Lighting Code clause 3.3 and JEN PR 0026 – Public Lighting Technical Standard Clause 8.0.

4.9.5.3.4 Public Lighting - Forecast Replacement Volumes

The proposed replacement volumes and the associated capital forecasts for the 2025 to 2031 period is relatively stable. A step change in the replacement strategy for obsolete luminaires on major roads is forecast for the next regulatory period. This is due to the change in strategy from current like-for-like replacement to the proposed LED replacement program to align with customer expectation and new technology. In addition, a CAPEX allocation is proposed for the proactive replacement of all minor road high pressure mercury vapour luminaires (MV80) in JEN.

Table 4-76 lists the forecast replacement volumes for public lighting from 2025 to 2031.

Table 4-76 Public Lighting Forecast Replacement Volumes

Unique ID	Service Code	Public Lighting	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A116	RLJ	Public lighting Replacement - Major Rd	403	271	481	4,197	4,387	1,567	3,880
A34	RLM	Public lighting Replacement - Minor Rd	3,508	508	1,659	8,245	7,986	4,162	8,995
A511	RLN	Single Lantern and Bracket Replacement - Major Rd	19	21	20	20	21	20	20
A512	RLO	Single Lantern and Bracket Replacement - Minor Rd	66	75	70	70	70	70	70
A78	RPA	Public lighting Pole Replacement - Major Roads	15	12	12	12	12	12	12

A513	RPB	Public lighting Pole Replacement - Minor Roads	123	101	180	180	180	180	180

4.9.5.4 *Asset Retirement and Disposal*

Due to the hazardous nature of some of the materials used in public lighting equipment particular attention is paid to their disposal. When replaced, obsolete public lighting assets will be disposed of in accordance with JAM PR 0060 WI 04 - Disposal of Public Lighting Equipment.

4.9.5.4.1 Overhead Public Lighting Switch Wire

A dedicated overhead switched active wire was historically used for the on-off control of the public lighting system. The “switch wire” is now obsolete as on-off control is now provided by PE cells integrated into modern luminaires. A significant amout of this “switch wire” remains installed on the JEN overhead network and there have been a number of incidents where it has been incorrectly identified. Its continued presence on the network constitutes a safety hazard.

Obsolete switch wire is to be removed on both an opportunistic basis during major maintenance works and via a planned program of removal. A program to remove switch wire was commenced by JEN in the previous regulatory period. The objective of this program is to remove the remaining public lighting switch wire to reduce operating inefficiencies and eliminate the risk associated with the incorrect identification of this conductor and the ongoing degradation of unmaintained assets. This program was completed in 2024.

4.9.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN’s activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.9.5.6 *Spares*

As part of the criticality assessment consideration is given to appropriate holdings of spare equipment. Spares requirements for critical assets are assessed by following the Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). It has been determined that adequate spares are maintained at the Tullamarine depot.

Standard public lighting equipment is kept in JEN stores with the quantities replenished as required.

Non-standard approved items are supplied by the customer.

4.9.6 INFORMATION

JEN’s AMS provides a hierarchical approach to understanding the information required to achieve JEN’s business objectives at the Asset Class level. The ACS provides the context for and determine the information required to manage and operate an Asset Class.

From these business objectives, it is possible to identify at a high-level the business information systems’ content required to support these objectives (Table 4-77).

Information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

Table 4-77: Public Lighting Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-78 identifies the current and future information requirements to support the Asset Class critical decisions and their value to the Asset Class.

Table 4-78: Public Lighting Sub-Asset Class Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Public lighting acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied public lighting equipment and detailed, repeatable installations appropriate to application.

Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Installation Use - Shared Cost Indicator - Maintained By - Road Class - Tariff Type - Feeder - Primary Customer - Date Commissioned - Date Lamp Changed - Zone - Ownership - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Lantern model • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-79 provides the information initiatives required to provide the future information requirements.

Included within this table is the risk to the Asset Class from not completing the initiative.

Table 4-79: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information capture	Ability to capture all relevant asset attributes from the field through mobility solution.	High	Complete, Current, Accurate attribution
Improved Asset Attributes	Review current asset attribution fields to ensure attributes being collected are asset specific.	Medium	Appropriate and Accurate attribution
Increased Timeliness	Decrease latency between fault/maintenance delivery and fault/maintenance record capture.	High	Complete, Current, Accurate attribution
Improved fault information capture	Ability to capture all relevant asset failure information from the field through mobility solution and photos.	High	Complete, Current, Accurate fault information

4.10 EARTHING SUB-ASSET CLASS

4.10.1 INTRODUCTION

The primary functions of an earthing system are as follows:

- To provide a voltage reference for the associated distribution system;
- To facilitate the passage of fault current at a level that will ensure the correct operation of network protection systems; and
- To mitigate the hazards associated with step, touch and transfer potentials that can occur under network fault conditions.

There are two performance criteria applied to the design of earthing systems. They are:

- The withstand strength; and
- The safety performance.

The withstand strength of an earthing system has to match the networks maximum designed fault level and longest protection clearance time. The safety performance of the earthing is assessed using a risk based approach and considers the probability of coincidence and the probability of a fatality occurring under normal network operating conditions. That is with all protection systems and primary plant in service.

Earthing systems are installed at:

- Every distribution substation;
- Every zone substation;
- All conducting structures and poles that house or support high voltage conductors or equipment;
- In conjunction with all high voltage cable heads and terminations;
- In conjunction with all high voltage surge diverter installations; and
- All high voltage metering structures and poles.

A variety of earthing systems have been historically uses across the JEN distribution substation network and these have included:

- Separate HV and LV earthing systems;
- Combined HV and LV earthing systems; and
- Common HV and LV earthing systems.

In order to improve the safety performance of distribution earthing systems generally JEN has adopted the Combined Multiple Earthed Neutral (CMEN) system of HV earthing wherever possible. This system uses the low voltage (MEN) neutral conductor to link all earthing systems and thus create a widespread low impedance earthing system to which all HV earths are bonded. This is combined with the installation of neutral earthing resistors at zone substations to reduce phase to ground fault levels and thus to improve the overall safety performance of the HV earthing system.

The CMEN system has been deployed, as far as is possible, in all of the urban neighbourhoods across JEN on the HV network. That is wherever the interconnected LV MEN neutral runs. In the remote parts of the network CMEN cannot be deployed as it requires the existence of an interconnected MEN neutral. In these locations the traditional earthing systems are deployed. It is acknowledged that these systems are not as effective as CMEN in the management of the hazards of step and touch potentials, but this is offset by the fact that these assets are located remotely and the probability of coincidence (the probability that someone is in a hazardous location at the time a fault occurs) is very low.

JEN has further extended the CMEN earthing system and bonded it to the zone substation earth grids. This has improved the safety performance of the zone substation earthing systems by lowering their impedance as well as improved the performance of the CMEN network by providing a direct path for the return of earth fault current on the HV network to the source zone substation. This reduces the magnitude of earth fault current in the ground, and this further mitigates earth potential rise on the distribution earthing systems.

This sub-asset Class Strategy for Earthing Systems is intended to ensure the ongoing performance of the JEN and to mitigate the network risk associated with the safety performance of earthing systems. Earthing and electrical protection systems must safely manage abnormal supply network conditions to avoid risk to people, or damage to property.

4.10.2 ASSET PROFILE

4.10.2.1 *Life Expectancy*

Table 4-80 outlines the useful life of earthing systems on JEN.

Table 4-80: Useful Life of Earthing Systems

JEN Asset	Useful Life of Earthing Systems
Earth Grids	50
NER (Neutral Earthing Resistor)	40
Resonant Earthing	40

4.10.2.2 *Age Profile*

The CMEN system of earthing has been implemented at all urban sites on JEN where it is the owner of the source zone substation.

A summary of the zone substation regions where and when CMEN has been introduced are listed in Table 4-81.

Table 4-81: CMEN implementation in the Zone Substation Regions

Year	Zone Substation Region
2020	Preston (PTN)
2017	Yarraville (YVE)
2015	Tullamarine Airport (TMA), Broadmeadows South (BMS)
2013	Heidelberg (HB), North Essendon (NS)
2011	Pascoe Vale (PV), Essendon (ES), Fairfield (FF)
2010	Footscray East (FE)

Year	Zone Substation Region
2008	Flemington (FT), Sydenham (SHM)
2007	North Heidelberg (NH)
2006	Coburg South (CS)
2004	Sunbury (SBY), Somerton (ST) Coolaroo (COO)
2003	Footscray West (FW), Tottenham (TH), Newport (NT)
2001	Airport West (AW), Braybrook (BY)
2000	Broadmeadows (BD), Coburg North (CN)

There are also small areas within the JEN distribution network (i.e., St Albans, Sunbury, Sydenham and Somerton) that are either supplied from adjacent Distribution Network Service Provider's zone substations that do not have NER's installed or are primarily in rural areas where no interconnected LV neutral conductor exists, and CMEN implementation has not occurred.

4.10.2.3 *Utilisation*

Earthing Systems are designed and installed to, as far as is possible, manage and control Earth Potential Rise (EPR) on the electrical apparatus they are connected to. On the JEN network they are generally passive devices that normally conduct little or no electrical current except under fault conditions. The exception to this is the earthing systems associated with the installation of LV Capacitance Balancing Units. These earthing systems can carry load current and special precautions need to be taken when approaching and testing these earthing systems.

Earthing systems are installed in contact with the general mass of earth utilising corrosion resistant materials that have a low impedance and a very long design life. They are generally comprised of a combination of stakes and conductor bonded together using reliable long life connection systems and laid out in a grid or pattern designed to spread the area of influence of the earthing system and achieve the desired earthing system impedance and thus manage any EPR.

4.10.3 PERFORMANCE

4.10.3.1 *Requirements*

Earthing systems must be made of corrosion resistant, high conductivity materials, specifically manufactured for the earthing of electrical installations. These materials include copper, copper alloy, brass and stainless steel. It should be noted that aluminium and steel are not suited for use in the construction of earthing systems as they readily corrode when in direct contact with the earth.

All metal and concrete structures located within 2.4 metres of the ground that support high voltage conductors and can be made alive in the event of primary insulation failure must be effectively earthed.

Table 4-82 outlines the earth resistance values that shall be achieved for various earthing installations as stated in the JEN internal standards.

Table 4-82: Earth Resistance - Installations

Equipment	Maximum Resistance of Earth System to ground			Maximum Resistance to Ground with Neutral Connected		Testing Requirements	
	HV	LV	Common	Common Earth System	Separate Earth System	Common Earth System	Separate Earth System
Pole/Ground/Indoor/Kiosk Substation	10Ω	10Ω ≥50KVA 30Ω <50KVA	10Ω	1Ω[9]	10Ω 30Ω	Common earth Common earth with neutral connected	HV earth LV earth
HV Switch/Fuse/Isolator	10Ω	N/A	N/A	N/A	N/A	N/A	HV earth
ACR	10Ω	N/A	N/A	N/A	N/A	N/A	HV earth
HV Surge arrester	10Ω	N/A	N/A	N/A	N/A	N/A	HV earth
HV Cable termination	10Ω	N/A	N/A	N/A	N/A	N/A	HV earth
HV concrete pole	10Ω	N/A	N/A	N/A	N/A	N/A	HV earth
HV Metering Structure/cubicle	10Ω	N/A	N/A	N/A	N/A	N/A	HV earth
HV Line Capacitors	10Ω	N/A	N/A	N/A	N/A	N/A	HV earth
LV Capacitance Balance Units	N/A	N/A	2Ω	N/A	N/A	Common earth	N/A

The requirements for the design, installation and performance of earthing systems on JEN are set out in the following manuals, standards and reports:

- The Distribution Construction Manual – ELE 999 OM CN 001 (previously JEN MA 0006)
- The Earthing Design Manual - SECV June 1995
- Strategic Planning Paper – Earthing Systems, Doc No. ST-PPDS-2013-087
- JEN Earthing Systems Report – 19/2/2019
- ZCMEN Program of Works
- HV Earth Testing Program in Non-CMEN Areas - JEN PR 2504

9 In CMEN systems the maximum resistance to ground of the common earth system prior to the neutral connection is 10Ω.

These JEN standards and reports are based on and reference a number of Australian Standards. Unless otherwise specified, all earthing systems shall be designed, manufactured and tested in accordance with the following principal Australian Standards and industry guides (refer to Table 4-83).

Table 4-83 Earthing Systems - Relevant Standards

Standard	Title
AS 2067 - 2016	Substations and High Voltage Installations Exceeding 1kV AC
AS/NZS 7000 - 2106	Overhead Line Design
ENA - EG-0	Power System Earthing Guide
IEEE 80:2000	IEEE Guide for Safety in AC Substation Grounding

4.10.3.2 *Assessment*

The CMEN system is being continually enhanced as new HV and LV assets are installed on the network and their associated earthing systems are bonded to the established CMEN system. There is no requirement to test the performance of earthing systems that are bonded to the CMEN earthing system. The requirements for the safety performance of the CMEN earthing system can be assessed using the criteria set out in AS 2067 and the ENA EG-0 guideline.

Non-CMEN earthing systems and the earthing installations associated with LV Capacitance Balance Units are tested every 10 years to ensure that the earth resistances comply with the performance criteria set out in Table 4-82 above. The safety performance of these standalone earthing systems can be assessed using the criteria set out in AS 2067 and the ENA EG-0 guideline.

The performance of Zone substation earth grids are tested every 10 years to ensure they comply with the safety requirements set out in AS 2067 and IEEE 80.

4.10.4 RISK

4.10.4.1 *Criticality*

An asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is used to rank importance of dissimilar sub-asset classes (e.g., transformers and buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

The earthing system sub-asset class has an asset criticality score of AC4 (High) due health and safety risk to staff and the general public associated with EPR and step and touch potentials.

4.10.4.2 *Failure Modes*

Failure modes include:

- Conductor corrosion causing high resistance or reduced fault current carrying capacity; and
- Conductor breakage due excavation, damage by machinery or vandalism.

Failure of earthing systems can also cause damage to equipment if protection systems are unable to operate in the manner in which the system was designed.

For details of the risk assessment, refer to relevant section in the JEN Compliance and Risk Management System (OMNIA).

4.10.4.3 *Current Risks*

The following table provides a summary of the current risks for earthing systems.

Table 4-84: Current Risks – Earthing Systems

Driver	Risk/Opportunity Description	Risk/Opportunity Description
Environment, Safety and Health	Earth potential rise (EPR)	This poses a risk to the public and employees and is something that needs to be actively managed on an ongoing basis, to ensure that changes in short circuit levels are managed appropriately.
Asset Integrity	Issues with theft of copper	On an annual basis, theft of copper (earthing) raises integrity issues for earthing systems that need to be managed on an ongoing basis.

For details of the risk assessment, refer to relevant section in JEN's Compliance and Risk System (OMNIA).

4.10.4.4 *Existing Controls*

There is no requirement to inspect and test HV earthing installations that form part of a CMEN system. The integrity of the CMEN earthing system relies on the application of construction standards that ensure all new high voltage installations are effectively connected to the CMEN network.

The inspection and testing of standalone HV earthing systems installed outside of the CMEN earthing system and zone substation earth grids is required at 10-yearly intervals in accordance with the requirements of the Electricity Safety (Network Assets) Regulations 1999 and JEN's Electricity Safety Management Scheme (ESMS). Any non-compliant earth grid or system found by test is reinstated to ensure the maintenance of compliant earthing systems.

Copper theft prevention guards are currently being installed to mitigate the risk of vandalism and theft targeting copper earthing cables. These guards act as physical barriers at vulnerable points along the distribution network, deterring unauthorized access and tampering.

4.10.4.5 *Future Risks*

Significant changes in network fault levels have the potential to impact upon the safety performance of JEN's earthing systems.

The maintenance of the engineered connections from zone substation earth grids to the surrounding CMEN earthing system needs to be monitored to ensure the safety performance of the ZCMEN systems.

4.10.5 LIFE CYCLE MANAGEMENT

The strategy applied to the life cycle management of this sub-asset class includes time based inspections followed by condition based maintenance and repair, as well as in-service failure based reactive maintenance (some degree of a run to failure strategy).

The earthing systems installed on JEN are designed, constructed and maintained in accordance with the requirements of the Electricity Safety (Network Assets) Regulations 1999 which have been incorporated in JEN's Electricity Safety Management Scheme (ESMS). JEN has conducted a Formal Safety Assessment as part of its ESMS submission to Energy Safe Victoria (ESV) which incorporated a risk assessment of the adequacy of JEN's current internal technical standards, in particular the requirement for inspection and testing of earthing systems in zone substations and non CMEN areas every 10 years. ESV has reviewed and approved JEN's ESMS.

4.10.5.1 *Creation*

Earthing systems are installed as part of any new installation of distribution and zone substation assets. New earthing systems are tested to ensure they meet the performance criteria specified for standalone earthing systems prior to bonding to the CMEN network.

4.10.5.2 *Asset Operation and Maintenance*

There are three (3) life cycle management strategies applied to the operation and maintenance of JEN's earthing systems:

- Asset Inspection;
- Preventative Maintenance; and
- Reactive and Corrective Maintenance.

4.10.5.2.1 Asset Inspection

The strategy for the maintenance of earthing systems through periodic inspections and tests is driven principally by:

- A duty of care requirement for the safety of our personnel and members of the public;
- A requirement for the business to comply with the JEN ESMS; and
- The need for correct and effective operation of network protection systems in the event of an earth fault, by ensuring there is sufficient fault current.

In general, with the exception of zone substation earthing systems, there is no requirement to inspect and test HV earthing installations that form part of a CMEN system. The inspection and testing of HV earthing systems installed outside CMEN schemes and zone substations are required at 10-yearly intervals.

4.10.5.2.1.1 Inspection and Testing - Non-CMEN Distribution Assets

Physical inspection of non-CMEN distribution assets (excluding non-pole distribution substations) is carried out every 3 years in the HBRA and every 4 years in the LBRA, to coincide with and as part of the standard asset inspection program. Refer to the JEN MA 0500 - Asset Inspection Manual for details.

Physical inspection of non-pole distribution substations is carried out every 3 years in the HBRA and every 4 years in the LBRA as part of the Enclosed Distribution Substation Inspection Program. Refer to the JEN MA 0695 – Enclosed Distribution Substations Inspection Manual for details.

The testing of these earths is required at 10-yearly intervals as part of the HV Earth Testing Program. Refer to JEN PR 2504 – HV Earth Testing Program in Non-CMEN Areas for details.

4.10.5.2.1.2 Inspection and Testing - Zone Substations

At 10-year intervals the following shall be undertaken to ensure earth grids continue to comply with safety criteria:

- Current injection tests to assess the impedance of the earth grid, the magnitude of the EPR under fault conditions, the magnitude and presence of any transfer hazards and the magnitude of any step and touch potentials;
- Sample inspections of underground conductors & conductor joints to check for any corrosion or damage.;
- A grid continuity test shall be conducted. This test measures the resistance between a main earth grid reference connection and each structure earthing point. This is particularly important for high energy dissipation points such as at surge arresters, portable earth points, and earth switch connection points;
- The condition of any crushed rock inside the substation for thickness and cleanliness. If the rock layer is filled with soil or grit its insulating properties may be compromised;
- Verify the integrity of all primary plant neutral earth connections; and
- Verify the integrity of engineered ZCMEN connections.

Whenever works occur in zone substations that involve the extension, modification or augmentation of the earth grid occur, the scope of works includes the conduct of the above tests to confirm the integrity and safety performance of the modified earthing system. This testing then resets the 10 year requirement for testing at the effected zone substation.

An annual physical integrity inspection shall be undertaken of all above ground structure earths, flexible earthing braids and bonds to equipment such as transformers, switchgear, cable sheaths, support framework and cubicles for all HV and LV equipment.

These earth tests are required even with the new strategy of bonding the zone substation earth grid to the CMEN network.

4.10.5.2.2 Preventative Maintenance

Condition based replacement or refurbishment is the preferred lifecycle management option for JEN’s earthing systems.

Replacement or augmentation of earthing system equipment results from the generation of maintenance notifications following asset inspection. Degradation can take the form of conductor and connector corrosion, vandalism or inadvertent damage due to excavation.

Earthing system augmentation is also undertaken when an earth resistance test result exceeds the maximum specified limits.

4.10.5.2.3 Reactive and Corrective Maintenance

Reactive and corrective maintenance is undertaken on earthing systems when inspection and testing activities have revealed that the system is damaged or degraded, or when a notification is received that an incident has damaged the earthing system (e.g., earths damaged by an excavator or vandalism).

The required earthing resistance for the various earthing arrangements shall be as specified on the appropriate earthing diagram for the particular installation and equipment.

4.10.5.3 *Asset Replacement*

There is no proactive replacement program for earthing systems.

4.10.5.4 *Asset Disposal*

Earthing systems are typically not removed from service, however, should disposal be required; it is scrapped according to the scrap material policy. Refer to JEM PO 1066 – Scrap Materials Policy for details.

4.10.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.10.5.6 *Spares*

As part of criticality assessment consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). It was determined that adequate spares are maintained at Tullamarine depot and stock holdings are managed by the Service and Projects team.

4.10.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determines the information required to manage and operate an Asset Class.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives (Table 4-85).

Table 4-85: Earthing Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-86 identifies the current and future information requirements required to support the critical decision making for the Asset Class and the value of the information to the Asset Class.

Table 4-86: Earthing Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Earthing materials acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied earthing materials and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Feeder - CMEN - HV/LV - Ownership - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-87 provides the information initiatives required to provide the future information requirements identified in Table 4-86. Included within this table is the risk to the Asset Class from not completing the initiative.

Information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

Table 4-87: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information	Field collection of incomplete asset attribution and assets	High	Complete, Current, Attribution Accurate
Network Performance Data	Ability to 'view' asset performance data from the GIS user interface or access an asset's historical performance data.	Medium	Complete, Current, Attribution Accurate, Consistent (GIS Asset ID to SAP Asset ID)
Improved Asset Attribution	Review of asset attribution fields to ensure attributes being collected are business specific	Medium	Attribution Accurate
Increased Timeliness	Latency between maintenance delivery and maintenance record capture decreased	High	Complete, Current, Attribution Accurate

4.11 HIGH VOLTAGE OUTDOOR OVERHEAD FUSE SUB-ASSET CLASS

4.11.1 INTRODUCTION

This section describes the type, specification, life expectancy and age profile of the HV outdoor pole mounted overhead fuses in service on distribution HV feeders on our network.

HV outdoor fuses are a simple and effective method of providing fuse protection. They are primarily employed as the protective device on pole type transformers, ground type substations and in some instances for the protection of indoor substations on cable head poles. They are also utilized to protect feeder backbones from faults on spur lines (mainly in the rural areas) and to protect under rated overhead conductor from burn down (fault level reduction).

There are three types of HV outdoor fuses used on the JEN on the 22kV, 11kV and 6.6kV distribution networks. They are expulsion drop out (EDO) fuses, powder filled (PF) fuses and boric acid (BA) fuses (refer to Table 4-88). The majority of fuses installed on the network are the BA type fuse, this is also the preferred fuse type. New EDO fuses are not installed on the network however stocks of fuse links are maintained to ensure ongoing operation of the existing population of EDO fuses. Where fault levels exceed the capabilities of BA fuses, PF fuses are used.

Table 4-88: HV Overhead Fuse Types

HV Overhead Fuse Type	Operating Volume			Total
	22kV	11kV	6.6kV	
Boric Acid (BA)	3032	433	102	3567
Expulsion Drop Out (EDO)	231	10	7	248
Powder Filled (PF)	816	86	19	921
Total	**4079**	**529**	**128**	**4736**

4.11.2 ASSET PROFILE

4.11.2.1 *Life Expectancy*

As prescribed in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for HV Outdoor Fuses is 40 years.

The above procedure considers asset lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has undertaken a number of reviews of asset useful lives with consulting agencies and held discussions with other Distribution Businesses to ensure assigned asset lives are realistic.

4.11.2.2 *Age Profile*

There are approximately 4,736 sets of HV outdoor overhead fuses in service on the network. These consists of 3,567 BA, 248 EDO and 921 PF fuses. Refer to the chart in section 4.7.2.2 for the age profile of HV outdoor fuses in service on the distribution network.

4.11.2.3 *Utilisation*

Approximately 75% of all HV outdoor overhead fuses in service on JEN are BA fuses, while EDOs only account for 5%. As per the JEN Fusing Guideline (ELE-999-GL-EL-001, previously JEN GU 0050), EDO type fuses are not to be used for new construction and replacement work. Any damaged EDO fuse mount shall be replaced with a new set of BA type fuses and mounts.

4.11.2.3.1 Expulsion Drop Out (EDO) Fuses

EDO fuses have been used in the VESI since 1952. An EDO fuse is a wire fuse (fuse wire in air) and consists of three parts; the fuse mount, the fuse holder or tube and the fusible link. When an EDO fuse operates, the molten fuse element is expelled explosively from the bottom of the fuse tube. These incendiary particles can result in the ignition of a fire when they hit the ground. Consequently, EDO fuses installed in the hazardous bush fire risk areas (HBRA**)** have a fire choke designed to catch and cool these particles to make the devices fire safe. Only EDO fuses fitted with fire chokes are permitted to remain in service in the HBRA and fault level at the location is below 2kA.

Once an EDO fuse has operated, the fuse tube is unlatched and swings down providing clear indication of fuse operation and isolation of the faulted equipment. They are inexpensive and when operated, the fusible links can be easily removed and replaced. Only three types of EDO fusible links are approved for use. They are Stanger “AK1”, ABB “Prolink” and AEM “Ultrafuse”. At very low fault levels EDO’s have been known to “hang-up” and candle. Candling occurs when the wire fuse element melts, but the fuse tube fails to drop. This results in the tube being electrically stressed and the resulting leakage current causes the fuse tube to burn.

As a result of the Ash Wednesday fires in 1983, ’unacceptable’ EDO fuses were identified for replacement throughout the VESI to mitigate fire risk. Since 1985, double vented EDO fuses were replaced by single venting fuses to reduce fire risks. EDO fuses have a limited fault interrupting capability and cannot be used where fault levels exceed 2kA. If these fuses are used in areas with fault levels in excess of 2kA, there is an increasing risk that the fuse tube will burst when attempting to interrupt fault current which will result in a possible feeder outage.

4.11.2.3.2 Power Filled (PF) Fuses

High Rupture Capacity (HRC) powder filled fuses have been used historically where the interruption of higher fault levels is required. A PF fuse consists of two parts, the fuse mount and the fuse body. The fusible elements are embedded in sand filler and are fully sealed in porcelain housings which therefore make the PF fuses significantly heavier than EDO fuses. Once the fuse has operated, the melting of the fusible elements turns the sand into glass and interrupts the fault current. The fault energy is all managed within the fuse with no molten material expelled from the fuse. For this reason, PF fuses are fire safe. The fuse is not rewireable and when blown the fuse must be replaced.

Although PF fuses are fully fault rated devices, care must be taken with their specification, selection and application. Full-range PF fuses offer fuse protection at all fault levels but are only available in a limited range of current ratings. General purpose PF fuse have a minimum breaking current limitation which means that if required to interrupt fault currents at levels below their minimum breaking current, then fuse candling and failure can occur. Fuse candling does have the potential to start a fire.

PF fuses do expel a small mechanical striker pin when they have operated to indicate that the fuse is blown. The fuse mounts that fit PF fuses are designed to use the expulsion of the striker pin to unlatch the fuse holder, so that when the fuse has operated the fuse swings down out on the holder in the same way as an EDO fuse does, providing clear indication of a fuse operation. The problem with this design is that the momentum associated with this action often causes the heavy PF fuse to be displaced from the mount and fall to the ground with the associated significant risk of injury. As a consequence, PF fuses are installed upside down in the fuse mounts so that when the fuse operates, the striker pin does not cause the unlatching of the fuse mount. This overcomes the safety issue but makes the identification of a blown fuse very difficult. The operation of these fuses is also difficult due to their weight and handling them on the end of a long HV operating stick can be hazardous as it is easy to lose control of the fuse and drop it during operations.

4.11.2.3.3 Boric Acid (BA) Fuses

Boric acid FSDs were introduced in the mid 1980's. The majority of fuses currently installed on JEN are boric acid fuses. BA fuses are a wire fuse that combines the advantages of EDO fuses with some of the capabilities of PF fuses. A BA fuse consists of two parts, the fuse mount and the fuse body or tube. BA fuses are not rewireable and when blown the fuse tube has to be replaced.

A BA fuse operates in the same way as an EDO fuse in that when the fuse operates, the wire fusible element melts and the molten products are expelled out of the bottom of the fuse tube. However, unlike an EDO fuse the BA fuse tube is lined with a solid boric acid material which cools the incendiary particles and makes the fuse safe for use in the HBRA. Similar to a PF fuse, when the BA fuse element blows a mechanical striker pin is expelled from the top of the fuse and unlatches the fuse holder. This causes the fuse tube to swing down and hang in this position providing clear indication that the fuse has blown and isolation of the faulted equipment. The BA fuse tubes are light weight, and this makes operation with a HV operating stick the same as for an EDO fuse.

BA fuses are full range fuses and have no minimum breaking current limitations. There is an upper limit on their interrupting capacity of 10kA. This means that these fuses can be installed in almost all parts of the network. A restriction has been placed on their use within 1km of a zone substation where a PF fuse should be used in these locations instead. However, the key consideration element is the fault level at the location of installation.

Fuse links with ratings up to 40 amps and manufactured prior to 1990 are particularly susceptible to "candling" and "hang-ups" with low current faults. The failures of these fuses result in burning of the fuse tube creating a fire hazard. These links can be readily identified, as they do not have green reflective tape or year of manufacture labels.

Moisture causes the Boric Acid liner to expand and in turn the operating rod to jam inside the tube resulting in the fuse tube not dropping out. This can lead to hang-ups and candling (slow burn). Hence fuse tubes are NOT to be stored hanging upside down in an open position in the fuse mounts for more than a day or left exposed to the weather e.g., awaiting commissioning. For details, refer to the Plant Bulletin for Handling of Boric Acid Fuses.

4.11.3 PERFORMANCE

4.11.3.1 *Requirements*

Unless otherwise specified, the HV fuses shall be designed, manufactured and tested in accordance with the following Australian Standards (refer to Table 4-89):

Table 4-89: Relevant Australian Standards

Standard	Title
AS 1033.1	High Voltage fuses (for rated voltages exceeding 1000V – Part 1: Expulsion type
AS 1033.2	High Voltage fuses (for rated voltages exceeding 1000V – Part 1: Current-Limiting (Powder-Filled) Type
AS 62271.105	High voltage switchgear and control gear – Alternating current switch-fuse combinations for rated voltages above 1kV up to and including 52kV

The equipment must be able to operate within the required performance parameters when exposed to climatic conditions in the state of Victoria.

For HV fusing technical requirements and fusing application tables, refer to ELE-999-GL-EL-001 JEN Fusing and HV & LV CB Setting Guideline document.

AS 1033.1 specifies the requirements for expulsion type fuses and this includes both Expulsion Drop Out and Boric Acid fuses. All fuses deployed in the HBRA parts of the JEN must be Class A type (sparkless) in accordance with the requirements of the standard and JEN's Bushfire Mitigation Plan. Powder Filled fuses are sparkless by virtue of their design and operating characteristics.

4.11.3.2 *Assessment*

Inspection of HV fuses is carried out as part of the standard asset inspection program. All poles and lines in the HBRAs are inspected every 3 years, and in the LBRAs every 4 years. A thermal survey of HV fuses is also performed to assist in the detection of potential failures before they occur and is aligned with the regular overhead line thermal survey cycle.

For details of the activities involved in the inspection program, refer to the JEN MA 0500 - Asset Inspection Manual.

On average maintenance notifications are raised on approximately 1.5% of the outdoor fuse population each year. In the main these relate to the operation of fuses. Asset replacement data reveals that as a result of these notifications approximately 0.2% to 0.3% (12 to 20 sets) of the population are replaced each year. This replacement rate points to a very reliable group of assets that are likely to have a service life that exceeds the forecast useful life.

4.11.4 RISK

4.11.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). Results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is also used to rank importance of dissimilar sub-asset classes (e.g., transformers and buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

The HV outdoor fuses sub-asset class has an asset criticality score of AC1 (Low) due to the consequence rating being minor.

4.11.4.2 *Failure Modes*

Common failure modes for HV outdoor fuses include:

- Insulator flashover due to deterioration, cracks or breakage of insulators and bird/animals;
- “Candling” which involves the overheating of fuse elements, particularly at low fault currents or overload currents, due to the fuse element not interrupting the current and continuing to conduct. These leads to failure of the fuse porcelain body or fuse tube;
- Failure of pivoting fuse holder to de-latch (hang up) on EDO and Boric Acid types; and
- Failure due to third party (e.g., weather and animal contact).

The major risks associated with HV outdoor overhead fuses are safety to people during maintenance and operation, supply reliability due to equipment failure or animals and the risk of fire start.

For details of the risk assessment, refer to the relevant section in JEN Risk and Compliance System (OMNIA).

4.11.4.3 *Current Risks*

This section provides information about HV outdoor overhead fuses, as well as general information about other potential issues. For details of the risk assessment, refer to relevant section in JEN's Compliance and Risk System (OMNIA).

There are currently no known systemic issues regarding HV outdoor overhead fuses. The performance of boric acid fuses is being monitored as there have been a small number of hang up failures related to failure of the striker pin to cause the fuse to drop out.

4.11.4.4 *Existing Control*

HV outdoor fuses are inspected as part of the standard asset inspection program. All poles and lines in the HBRAs are inspected every 3 years, and in the LBRAs every 4 years. A thermal survey of HV fuses is also performed to assist in the detection of potential failures before they occur and is aligned with the regular overhead line thermal survey cycle.

4.11.4.5 *Future Risks*

No future risks associated with HV outdoor overhead fuses have been identified.

4.11.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy covers time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance.

4.11.5.1 *Creation*

HV outdoor fuses are installed for the protection of distribution transformers and overhead spur lines. Every pole top transformer has a set of fuses installed to protect the distribution network from a fault on a transformer and its associated equipment and they serve as the HV isolating device for the transformer. The size and detail of the fuses to be installed at each location is described in JEN's fusing guide (ELE-999-GL-EL-001).

4.11.5.2 *Asset Operation and Maintenance*

The lifecycle management options of HV outdoor overhead fuses are:

- Asset Inspection;
- Proactive Maintenance;
- Reactive and Corrective Maintenance; and
- Run to Failure.

4.11.5.2.1 Asset Inspection

Inspection of HV fuses is carried out as part of the standard asset inspection program. All poles and lines in the HBRA are inspected every 3 years, and in the LBRA every 4 years. A thermal survey of HV fuses is also performed to assist in the detection of potential failures before they occur and is aligned with the regular overhead line thermal survey cycle.

For details of the activities involved in the inspection program, refer to the JEN MA 0500 - Asset Inspection Manual.

When opportunities arise, such as repair of overhead conductor faults, all fuses should be inspected for cleanliness, signs of tracking, cracks on fuse mounts and carriers and that the lead connections, and bird and animal covers are secured.

4.11.5.2.2 Proactive Maintenance

4.11.5.2.2.1 Condition Based Replacement or Refurbishment

Fuses are replaced according to the JEN GU 0010 – JEN Planned and Opportunistic Maintenance and Workmanship Guidelines and JEN MA 0500 – Asset Inspection Manual. This includes but is not limited to:

- signs of tracking, cracks on fuse mounts and carriers;
- unacceptable EDO fuses, e.g., old brown porcelain EDO;
- as part of planned work such as pole or HV fuse crossarm changes, EDO fuses are to be replaced with the current standard i.e., BA or PFF;
- as part of planned work such as pole or HV fuse crossarm changes, any BA fuse mounts within 1 km of a zone substation with maximum fault levels greater than 10kA shall be changed to PFF; and
- as part of planned work such as pole or HV fuse crossarm changes, any PFF fuse mounts more than 1 km of a zone substation with maximum fault levels less than 10kA shall be changed to BA.

4.11.5.2.2.2 Proactive Replacement Program

There are no proactive replacement programs currently for the replacement of HV outdoor overhead fuses. Opportunistic replacement in accordance with the above requirements will occur in conjunction with network augmentation or redevelopment.

4.11.5.2.3 Reactive and Corrective Maintenance

Corrective maintenance shall be used to repair defects and faults identified during inspections or problems that occur during service.

When blown fuses are replaced or repaired the following should be inspected:

4.11.5.2.3.1 EDO Fuses

- Mounts;
- Excess fuse link tails are cut off and not poked back in the fuse carrier;
- Carriers or tubes are clear of obstructions such as mud wasp nests;
- Check the carriers for warping, bowing, tracking and arcing damage and are not therefore prone to “hang-up” or candling; and
- Note: (EDO fuse mounts are not maintained, they are replaced with BA fuses)

4.11.5.2.3.2 Powder Filled Fuses

- Mounts;
- Contacts on the top and bottom clamping rings are in line and are clean;
- Striker pin is facing down (at the bottom clamping ring); and
- Correct size clamping rings are selected to fit the fuse link.

4.11.5.2.3.3 Boric Acid Fuses

- Mounts;
- Top and bottom clamping fittings are located on the fuse link correctly, (spigots are fitted on the fuse link to ensure correct location), and securely tightened;
- Breaking latch on the top contact of the mount hinges freely;
- Travel of the de-latching pin is not impeded (check the hole in the top of the top fitting is not blocked);
- When link is closed, the red plastic vent cover points down; and
- Fuse Links should have red plastic vent cover fitted.

4.11.5.2.3.4 All Fuses

- Porcelain is undamaged, free of tracking, cracking and chipping;
- Fixed contacts are clean and lightly graphite greased;
- Line connections are tight; and
- Fuse carrier hinges freely in the bottom mount and latches properly when closed.

4.11.5.2.4 Run to Failure

Apart from opportunistic replacement to ensure acceptable fuses are used, fuses are consumable assets and are designed for run to failure. Whenever fuse elements operate, they are replaced once a patrol establishes the likely cause of the fault.

4.11.5.2.5 HV Outdoor Overhead Fuse Forecast Replacement Volumes

Table 4-90 lists the forecast replacement volumes for HV outdoor overhead fuses from 2025 to 2031, based on condition.

Table 4-90: HV Outdoor Overhead Fuse Forecast Replacement Volumes

Unique ID	Service Code	HV Outdoor Overhead Fuses	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A217	RXF	Fuse unit replacement	20	19	20	20	20	20	20
A217	RXF	Fuse Units Replace (Single)	8	8	8	8	8	8	8

4.11.5.3 *Disposal*

HV outdoor overhead fuses are typically not repaired but instead are replaced as required. HV outdoor overhead fuses should be disposed of in accordance with JEM PO 1600 – Scrap Materials Policy.

4.11.5.4 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.11.5.5 *Spares*

Fuse mounts and components are stocked in the stores and replenished based on historical purchase orders and 75% of 6 month usage for summer preparation. A full range of spare fuse elements are kept at the Tullamarine depot and emergency stocks are held in satellite store locations to facilitate timely responses to network outages.

4.11.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determines the information required to manage and operate an Asset Class.

The Electricity Distribution ACS facilitates the safe, efficient and reliable delivery of electricity to JEN's customers.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives.

Table 4-91: HV outdoor Overhead Fuses Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-92 identifies the current and future information requirements required to support the critical decision making for the Asset Class and the value of the information to the Asset Class

Table 4-92: HV Outdoor Overhead Fuses Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
HV outdoor fuse acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied HV outdoor fuses and fuse mounts and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Use - Type (e.g., EDP, BA) - Physical Location (Melway reference, closest address / intersection) - Feeder - Operational Tag - Ownership - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Fuse rating • Manufacturer • Phase • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-93 details the information initiatives required to provide the future information requirements identified in Table 4-92. Included within this table is the risk to the Asset Class from not completing the initiative.

Information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

Table 4-93: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information	Field collection of incomplete asset attribution and assets	High	Complete, Current, Attribution Accurate
Network Performance Data	Ability to 'view' asset performance data from the GIS user interface or access an asset's historical performance data.	Medium	Complete, Current, Attribution Accurate, Consistent (GIS Asset ID to SAP Asset ID)
Improved Asset Attribution	Review of asset attribution fields to ensure attributes being collected are business specific	Medium	Attribution Accurate
Increased Timeliness	Latency between maintenance delivery and maintenance record capture decreased	High	Complete, Current, Attribution Accurate

4.12 DISTRIBUTION SURGE ARRESTERS SUB-ASSET CLASS

4.12.1 INTRODUCTION

This section describes the type, specification, life expectancy and age profile of distribution surge arresters on distribution HV feeders across JEN.

Surge arresters are passive overvoltage protection devices that are typically installed on pole mounted distribution substations, automatic circuit reclosers (ACR's), gas insulated switches and cable head poles. They are installed to protect these devices from damage in the event of network overvoltage's that are associated with lightning strike and network switching.

Table 4-94 indicates number of distribution surge arrestors in service by type and application. It should be noted that issues with asset data quality has resulted in a large number of surge diverter sets being listed as "other" in the list of applications below. It is reasonable to assume that the majority of these are in fact associated with pole top transformers as there are 4,255 of these installations and the vast majority are fitted with surge diverters.

Table 4-94: Distribution Surge Arresters by Type

Type	Applications							Total
	HVABC	Overhead Line	Regulator	Switches	Transformer	Cable Heads	Others	
Blue Porcelain	0	8	0	1	12	5	3	**29**
Brown Porcelain	0	4	0	2	9	12	0	**27**
Expulsion	0	0	0	0	1	0	0	**1**
Grey Porcelain	1	83	0	25	346	132	15	**602**
Polymeric	8	416	2	384	2,066	1,170	2,606	**6,652**
Total	**9**	**511**	**2**	**412**	**2,434**	**1,319**	**2,624**	**7,311**

4.12.2 ASSET PROFILE

4.12.2.1 *Life Expectancy*

As prescribed in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for Distribution Surge Arresters is 25 years.

The above procedure considers asset lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has undertaken a number of reviews of asset useful lives with consulting agencies and held discussions with other Distribution Businesses to ensure assigned asset lives are realistic.

4.12.2.2 *Age Profile*

There are a total of approximately 7,311 sets of distribution surge arresters in service. Furthermore, as shown in Table 4-94, approximately 90% of the total population of distribution surge arrester are the polymeric housed type. This is because of a number of large programs that targeted the replacement of 'unacceptable' surge arresters. The principle driver of these replacement programs has been the commissioning of Neutral Earthing Resistors at zone substations located across the entire JEN and the requirement for the installation of Class A surge arresters in the HBRA.

4.12.2.3 *Utilisation*

HV surge arresters are passive devices that do not operate or function under normal operating conditions. Modern surge arresters are non-linear varistors activated by over-voltage conditions that result from network switching or lightning events. They are designed to provide overvoltage protection of network assets by shunting over voltages to earth.

Historically, various over-voltage protection devices have been installed. Rod gaps and silicon carbide type surge arresters were used on the State Electricity Commission of Victoria (SECV) system. Prior to 1975, silicon carbide surge arresters were not fitted with pressure relief devices and their failures were known to be explosive. Subsequently, pressure relief devices and earth lead disconnects were introduced to mitigate this safety hazard and to assist with fault location. Earth lead disconnects were fitted to 5kA rated arresters and not 10kA rated arresters as these arresters had higher energy handling capabilities. These have not been installed since 2000 on the JEN network.

In 1985, zinc oxide type surge arresters were used for the first time as their operating voltages were more accurate than silicon carbide units. Their residual voltages were also lower than silicon carbide units, offering greater protection for network assets.

Whilst the electrical characteristics of surge arresters were improving, it was recognised that structural weakness still remained. Some surge arresters employing porcelain as the housing medium were failing explosively with the resulting hazards associated with shattered pieces of porcelain. To mitigate this safety hazard, surge arresters utilising polymeric housings were introduced in 1994. In general, the polymeric surge arresters are proving to be far more reliable than their old porcelain counterparts as they better seal the active components from the ingress of moisture.

There are 2 types of surge arresters approved for installation as standard within the JEN 22kV network. These are Class A, ABB Polim 24kV, 10kA arrester for the HBRA and Class C, ABB Polim 24kV, 10kA arrester for the LBRA. A third type of surge arrester is used as standard for the 11kV and 6.6kV network, these are Class C, Insulect 12kV 10kA arresters.

The surge arresters selected for use on the 22kV network are suitable for use with resonant earthing (REFCL) systems.

4.12.3 PERFORMANCE

Distribution surge arresters are designed, manufactured and tested in accordance with the following Australian Standards (refer to Table 4-95):

Table 4-95: Applicable Australian Standards - Distribution Surge Diverters

Standard	Title
AS 60099.4	Surge arresters – Metal-oxide surge arresters without gaps for a.c. systems
AS 60099.5	Surge arresters – Selection and application recommendations
AS 1768	Lightning Protection

All new surge diverter housings are polymeric thus reducing the risk rating for public safety and liability. Furthermore, distribution surge arresters are specified pressure relief category “NS” (Non-Shattering) as per AS 60099.4

4.12.3.1 *Requirements*

The requirements for surge arresters are specified in the JEN 22kV and 11kV Surge Arrester Technical Specification. The equipment must satisfy the required performance parameters when exposed to climatic conditions in the state of Victoria.

4.12.3.2 *Assessment*

The monitoring and optimisation of the performance of HV surge arresters is achieved through the following:

- Maintenance notifications;
- The monitoring of network outages as a result of surge arrester mal-operation or failure and subsequent failure of a distribution transformer or other distribution supply equipment, contributing to customer reliability and service target performance incentive scheme (STPIS) targets;
- The monitoring of fire starts, as a result of surge arrester failure, contributing to the JEN fire performance incentive scheme (F-Factor) targets; and
- The monitoring of network incidents reportable to Electricity Safety Victoria (ESV).

Each of these measures is reported on a monthly basis as part of the JEN Customer & Asset KPI's at an aggregate level.

These targets align with the JEN Strategic Objectives under Customer, Safety & Asset Management.

4.12.3.2.1 Maintenance Notifications

HV surge arresters are condition monitored via the asset inspection programs to ensure that they remain in a serviceable and operable condition. They are inspected as a part of the asset inspections that occur every 3 years in HBRA and 4 years in the LBRA. Consequently, maintenance notifications are raised when defects are detected via inspection and corrective maintenance, or replacement tasks are scheduled to ensure the safety, operability, and reliability of this group of assets.

Table 4-96 below shows the in-service failures associated with surge arresters and the corresponding cause descriptions. It can be seen that the rate of equipment failure is trending down, and this is consistent with the relatively young age profile associated with these assets. The reliability of these assets has benefited from the extensive asset replacement programs driven by the bushfire mitigation programs and the installation of NER's and REFCL earthing systems.

Bird and animal strike continues to be problem effecting the reliability of these assets. This is despite a large effort to ensure the installation of animal and bird guards on distribution assets such as surge arrestors.

Table 4-96: HV Surge Arrester In-service failures

Cause	Year							
	2015	2016	2017	2017/18	2018/19	2019/20	2020/21	2021/22
Animal/Bird	5	7	2	15	9	14	12	11
Asset Failure	7	8	5	3	2	2	1	1
Total	**12**	**15**	**7**	**18**	**11**	**16**	**13**	**12**

N.B. Asset failure includes failures due to 66kV injection.

4.12.3.2.2 Fire Starts

After the bushfires in the late 1970's and early 1980's, reports indicated that surge arresters were related to a number of fire starts and many arresters were deemed 'unacceptable'. These arresters have been removed from service as part of bushfire mitigation strategy. A small percentage of ‘unacceptable’ surge arresters may still exist in non-bushfire areas. A complete list of unacceptable surge arresters can be found in the ‘Acceptable HV Fuse and Surge Arrester’ handbook. Document number: SP 4147 (Sept 1997).

4.12.4 RISK

This chapter includes information about surge arrester risk profiles involving the way that asset class criticality is established, the risks posed by surge arrester failure (including the various failure types and their possible consequences), other measures being introduced to manage asset risk, and a list of the various issues currently confronting surge arresters.

This information specifically involves:

- asset class criticality;
- failure risks, types, and consequences; and
- asset issues

4.12.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. An asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). . Results of this assessment are presented in Appendix A. The asset criticality score is then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN’s operational objectives. This is also used to rank the importance of dissimilar sub-asset classes (e.g., transformers and buildings and grounds) to identify areas where risk should be managed first and control measures implemented. Distribution surge arrester sub-asset class has an asset criticality score of AC2 (Moderate).

Surge arresters contribute to JEN’s overall service level and network performance via the overvoltage protection they provide to the distribution asset class. There are approximately 7,311 surge arresters sets installed on the JEN, of which, approximately 4,000 sets are protecting transformers. The failure of the surge arrester to operate correctly exposes an in service transformer to network over-voltages which if left undetected could potentially result in a catastrophic transformer failure and subsequent network outages.

4.12.4.2 *Failure Modes*

Surge arrester failures include:

- External flashover of housing;
- Internal flashover, causing housing rupture, often due to moisture ingress in porcelain housed units; and
- Internal conduction of 50Hz current, often with housing rupture (e.g., 66kV injection).

The major risks associated with surge arresters relate to public safety. This is associated with the explosive failure of surge arresters, in particular porcelain housed types, which results in airborne shattered porcelain. This can result in property damage and/or personal injury and the associated liability and claims. It should be noted that this risk has been significantly mitigated by the replacement of porcelain housed surge arresters with polymeric housed surge arresters. Other risks include equipment failure resulting in a fire start, which has a financial impact on JEN under the regulatory bushfire F-Factor scheme.

For details of the risk assessment, refer to the relevant section in JEN Risk and Compliance System (OMNIA).

4.12.4.3 *Current Risks*

After bushfires in the late 1970's and early 1980's, reports indicated that surge arresters were related to a number of fire starts and many arresters were deemed 'unacceptable'. These arresters have been removed from service as part of bushfire mitigation strategy. A small percentage of 'unacceptable' surge arresters may still exist in non-bushfire areas. A complete list of unacceptable surge arresters can be found in the 'Acceptable HV Fuse and Surge Arrester' handbook. Document number: SP 4147 (Sept 1997).

Historically, Neutral Earth Resistors (NERs) were introduced on JEN to improve the quality of supply, reduce the risk of bushfire ignition during phase to ground faults, and reduce hazardous step and touch potentials present during fault conditions, in particular associated with conductive or concrete poles . The risk of bushfire ignition is proportional to the amount of energy let through during the fault (or I^2t). The NER limits the available phase to ground fault current to approximately 2kA, which is a significant reduction in the fault energy and therefore the risk of bushfire ignition.

The NER and related CMEN program was completed in 2010. As a result, in those parts of the JEN supplied by NER equipped zone substations the temporary over-voltages experienced by surge arresters under earth fault conditions increased significantly. This is a consequence of the change from an effectively earthed to a resistance earthed distribution network. Older specification or 'unacceptable' surge arresters were particularly prone to failure due to the higher phase to earth voltages experienced under fault conditions. These surge arresters were actively identified and replaced prior to the commissioning of the NER's.

The use of Rapid Earth Fault Current Limiter (REFCL) technology to mitigate bushfire risk by further reducing phase to earth fault current has further implications for the performance of surge diverters under fault conditions. Surge arresters installed on HV feeders associated with zone substations where a REFCL system is installed need to be able to withstand high phase to earth voltages (phase to phase voltages) for an extended period under fault conditions. In preparation for the implementation of REFCL systems new surge arrester specifications have been developed. The current specification for surge diverters of 24kV Class A and 24kV Class C surge diverters meet this criteria.

4.12.4.4 *Existing Control*

HV distribution surge arresters are inspected as part of the standard asset inspection program. All poles and lines in the HBRAs are inspected every 3 years, and in the LBRA every 4 years. A thermal survey program of HV feeders is also performed cyclically to assist in the detection of potential failures before they occur.

Pro-active replacement of surge arresters occurs as part of NER and REFCL implementation projects. This is a key objective of JEN's Asset Management strategy and focuses on maintaining network reliability and safety. The replacement of "unacceptable" surge arresters is related to successfully achieving this.

4.12.4.5 *Future Risks*

REFCL technology significantly reduces the risk of bushfire start. JEN has committed to a program that will introduce REFCL technology at all new and existing high exposure bushfire zone substations and the deployment of REFCL technology for low exposure bushfire zone substations over the next 10 years.

Consequently, as indicated above, the specification of distribution surge diverters for use on the JEN has been modified to ensure they are matched to the changed operating conditions that exist when a REFCL system of earthing is installed. Proactive programs to replace surge diverters located in these areas will be required before a REFCL system can be commissioned.

4.12.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy covers time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance.

4.12.5.1 *Creation*

Distribution surge arresters are installed on the network in conjunction with the installation of new distribution substations, cable head poles and overhead line switchgear in accordance with the current JEN standards. They are also purchased and held with minimum stock levels designed to support network development and maintenance requirements.

Currently JEN purchases Class A, ABB Polim 24kV, 10kA surge arrester for the HBRA and Class C, ABB Polim 24kV, 10kA surge arrester for the LBRA.

A third type of surge arrester is used as standard for the 11kV and 6.6kV network, these are Class C, Insulect 12kV 10kA arresters.

<u>Note:</u> As of early 2015, the 22kV Class C TE Tyco surge arrester (TE BOW_DA1-27H-B7F0N0-I-212) is no longer being procured or installed on the JEN.

Four scenarios trigger the need to acquire and connect new surge arresters:

- Installation of new equipment requiring overvoltage protection;
- The proactive preparation of the distribution network for REFCL implementation;
- Replacement due to failure or damage; and
- As a part of routine maintenance as a result of overhead line inspection programs

The various types of distribution surge diverters are typically purchased under period contracts in accordance with the Distribution Construction Manual and equipment specification requirements.

4.12.5.2 *Asset Operation and Maintenance*

There are four (4) life cycle management strategies applied to the operation and maintenance of JEN's distribution surge arresters:

- Asset Inspection;

- Preventative Maintenance;
- Reactive Maintenance; and
- Run to Failure.

4.12.5.2.1 Asset Inspection

As well as routine asset inspection programs, when opportunities arise such as repair of pole top structures, all surge arresters should be inspected to ensure that:

- Signs of tracking, cracks on porcelain or polymeric housing are reported;
- Earth lead disconnect devices (where fitted) are of the acceptable type and have not operated;
- Pressure relief device has not operated;
- Line and earth lead connections are secured;
- Bowthorpe fault indicators have not operated;
- Any "unacceptable" surge diverters are identified; and
- Bird and animal covers are fitted correctly with no bare HV exposed (except on cable head pole installations where there is an earth attachment point) and have not perished

Notifications are raised against each of the above listed criteria in accordance with the Asset Inspection Manual.

In addition to asset inspection infra-red (thermal) surveys are conducted on 1-2-3 year cycle and a notification will be raised to replace a surge arrester based on these surveys for proactive replacement.

4.12.5.2.2 Preventative Maintenance

4.12.5.2.2.1 Proactive Replacement

A number of programs of proactive replacement of distribution surge arresters has occurred over the past 20 years to address various performance issues. In each case the targeted surge diverters have been replaced with the current standard polymeric surge arresters. The prime driver for these replacement programs has been the replacement of "unacceptable" surge diverters in the HBRA and the replacement of distribution surge arresters that were not compatible with the roll out of NER's and REFCL earthing systems. – The Asset Inspection Manual (JEN MA 0500) defines a list of "unacceptable" surge arresters, and the suitable replacement devices dependent on location (within or outside of the HBRA).

"Unacceptable" arresters, are also shown in the document titled "HV Fuses & Surge Arresters Handbook", and these are to be replaced to mitigate the public safety risk due to the potentially explosive nature of their failure mode.

When surge arresters are inspected, the following should be checked and actioned as necessary.

4.12.5.2.2.1.1 ABB Surge Arrester TVI

Between 1997 and 1998, some of the type MVK and MWK surge arresters supplied by ABB were found to cause Television Interference (TVI). The problem was attributed to the use of a new type of resistor in the earth lead disconnector to replace parts that were no longer produced. When identified, all three surge arresters of this type shall be replaced.

4.12.5.2.2.1.2 Old ABB CHP Polymeric Surge Arresters – Horizontally Mounted

ABB CHP polymeric arresters are to be mounted on the correct bracket at an angle to ensure that the pollutants on the arresters will be washed and cleaned by rain. Horizontally mounted old ABB surge arresters and their specific mounting brackets are to be replaced when they are identified.

4.12.5.2.2.1.3 Surge Arresters on Transformers

For best protection, arresters on transformers are to be mounted directly on the tank. As an indication, for every metre of separation between the arrester and the transformer, the residual voltage on the transformer can rise by up to 5kV.

Where substations are found with surge arresters mounted on the pole top and some distance away from the transformer HV bushings, the surge arresters should be relocated downstream of the HV fuse and onto the transformer tank adjacent to the transformer bushings.

4.12.5.2.2.1.4 Surge Arrester Clearance on Cable Head Poles

When surge arresters are replaced, the existing cluster brackets must be removed, and new mounting brackets (Distribution Construction Manual SP9/7029/15) must be used to increase the phase to phase clearance of the arresters. If space is restricted, use an adaptor bracket arrangement (Drawing No SP17/115/38).

4.12.5.2.2.1.5 22kV Class C TE Tyco surge arrester (TE BOW_DA1-27H-B7F0N0-I-212)

These surge arresters were recalled by the manufacturer. A small number were installed in the field, and these were removed from service. If they are found in service, they should be replaced.

4.12.5.2.2.1.6 Review Following a Fault on a Line

If surge arrester disconnect leads have operated at an installation, the surge arresters must be isolated to avoid TVI and the risk of a feeder outage and scheduled for replacement.

If an installation is known to have experienced a recent 66kV injection, then all three arresters are to be replaced regardless of their physical condition.

4.12.5.2.2.1.7 Unacceptable Surge Arresters

In 1997 a recommendation was made to initiate a program to replace “unacceptable” surge arresters which were displaying evidence of increased failure rates. There were brown porcelain, single vented grey porcelain and Cooper polymeric (early polymeric versions) types of surge arresters.

In 1999 the program to replace the “unacceptable” surge arresters was completed. At the time Bowthorpe surge arresters were installed as replacements. Subsequently, approximately 18 months after their installation it was found that the Bowthorpe HEB24 & EGB24 series of EDPM type polymeric surge arresters were failing. As a consequence, these were also added to the “unacceptable” surge arrester list; refer to Table 4-97.

For visual identification of “unacceptable” arresters, refer to JEN MA 0500 - Asset Inspection Manual.

Table 4-97: Unacceptable Distribution Surge Arresters

Type	Comment
Brown Porcelain	Typically installed in the 50’s and 60’s when the feeders were constructed.
Grey porcelain	Exhibited elevated failure rates due to a fundamental design flaw.
Cooper Polymeric (1992 versions)	Identified with inadequate voltage ratings on stations where NERs are installed.

Bowthorpe HEB24 & EGB24	Failing due to a surface tracking problem caused by a build-up of air borne pollutants on sheds of the surge arresters

It is essential that all “unacceptable” surge arresters identified in the bushfire areas are replaced as priority items (within 12 weeks). In non-HBRA areas, the surge arresters are to be replaced during substation maintenance or as part of targeted replacement programs.

4.12.5.2.2.2 Condition Based Replacement

As distribution surge arresters are a component of HV overhead structures, inspection of surge arresters is conducted as part of the overhead line inspection program. Inspection criteria are documented in JEN MA 0500 - Asset Inspection Manual. Condition assessment of distribution surge arresters is conducted to identify defects in the electrical connections, evidence of tracking, cracks, splits and heavy build-up of pollution during which time notifications are raised for the rectification of defects or replacement of assets as identified.

The identification of defects and the raising of maintenance notifications against distribution surge arresters is only possible via visual and physical inspection of the asset. Early identification and replacement of damaged or failed surge arresters is crucial to maintaining the overvoltage protection of the distribution asset class. Ongoing asset inspections will identify any physical signs of asset failure before they occur. This is the preferred method for the lifecycle management of distribution surge arresters.

4.12.5.2.3 Reactive And Corrective Maintenance

Surge arresters are not repaired as they are not maintainable.

Surge arresters are considered to be maintenance free. They have an expected useful life of 25 years provided they are correctly installed. No preventive maintenance is undertaken for this asset class.

4.12.5.2.4 Run to Failure

Run to failure is a replacement strategy which can be employed on low cost / high volume and consumable assets, in which the consequence of failure is low or when failure rates are low. The application of this strategy requires that any resultant outage can be responded to in a timely manner and that the required spares and resources are available.

The data on surge arrester notifications indicates that between 2003 and 2022, 193 sets of HV surge arresters have had notifications raised against them due to network incidents related to the following damage codes:

- Failed mechanical integrity (mechanical failure/deterioration);
- Failed required insulation level;
- Failed required mechanical support;
- Failed to carry load;
- Failed to contain insulating medium;
- Failed to provide lightning protection;
- Open circuit; and
- Short circuit.

These codes provide an indication of the manner in which surge arresters have failed in service or have failed electrically due to an over voltage event.

As surge arresters are passive devices that do not operate until a transient overvoltage event occurs, it is not possible to analyse a unit's condition other than by visual inspection for obvious abnormalities such as surface tracking or damage to the housing and sheds.

4.12.5.3 *Surge Arrester Forecast Replacement Volumes*

Surge diverters are to be replaced at a rate aligned with historical expenditure which covers fault replacement and asset inspection notifications.

Table 4-98: Surge Arrester Forecast Replacement Volumes

Unique ID	Service Code	Surge Arresters	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A216	RXD	Surge Diverter Replacement (set)	24	31	40	40	40	40	40
A216	RXD	Surge Diverter Replacement (Single)	2	2	2	2	2	2	2

The age profile of this group of assest reflects the large amount of work that has been done to rid the network of underspecified or unacceptable types of surge diverters. The vast majority of the remaining population are polymeric housed surge diverters which has addressed the risks associated with the explosive failure mode associated with porcelain surge diverter housings. Given that the oldest surge diverters on the network are only 25 years old then it is not anticipated that large scale replacement programs will be needed for the next 10 years and replacement rates will remain modest and driven by the asset inspection programs.

4.12.5.4 *Disposal*

Surge arresters are not normally repaired they are always replaced after a surge arrester fault.

Surge arresters do not contain hazardous materials and should be disposed of in accordance with JEM PO 1600 – Scrap Materials Policy.

4.12.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.12.5.6 *Spares*

As part of criticality assessment consideration is given to appropriate levels of spare equipment. Spares requirements for critical assets are assessed by following the Critical Spares Assessment Procedure (ELE-999-PR-RM-002, previously JEM AM PR 0015). It was determined that adequate spares are maintained at Tullamarine depot.

4.12.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determines the information required to manage and operate an Asset Class.

The Electricity Distribution ACS facilitates the safe, efficient and reliable delivery of electricity to JEN's customers.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives (Table 4-99).

Table 4-99: Distribution Surge Arresters Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-100 identifies the current and future information requirements required to support the critical decision making for the Asset Class and the value of the information to the Asset Class.

Table 4-100: Distribution Surge Arresters Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Distribution surge arrester acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of quality of supplied surge arresters and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Manufacturer - Model - Rating - Voltage - Usage - Type - No of units - Earth Lead Disconnect Device - Feeder - Date Installed - Date Removed - Inspection Zone • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Surge arrester class • Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-101 provides the information initiatives required to provide the future information requirements identified in Table 4-100. Included within this table is the risk to the Asset Class from not completing the initiative.

Information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

Table 4-101: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information	Field collection of incomplete asset attribution and assets	High	Complete, Current, Attribution Accurate
Network Performance Data	Ability to 'view' asset performance data from the GIS user interface or access an asset's historical performance data.	Medium	Complete, Current, Attribution Accurate, Consistent (GIS Asset ID to SAP Asset ID)
Improved Asset Attribution	Review of asset attribution fields to ensure attributes being collected are business specific	Medium	Attribution Accurate
Increased Timeliness	Latency between maintenance delivery and maintenance record capture decreased	High	Complete, Current, Attribution Accurate

4.13 AUTOMATIC CIRCUIT RECLOSER SUB-ASSET CLASS

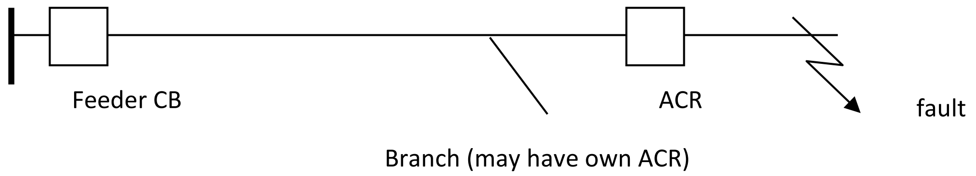
4.13.1 INTRODUCTION

This section describes the type, specifications, life expectancy and age profile of the ACR's in service on JEN's distribution feeders.

ACR's are self-contained light duty circuit breakers complete with overcurrent, earth fault and sensitive earth fault protection and automatic reclose functionality. They have traditionally been used on the overhead sections of high voltage distribution feeders which have a high frequency of both permanent and transient faults however they are now used across the network to improve network performance and to facilitate the remote control and automation of the HV distribution network.

Upon detecting a fault current greater than its programmed setting, the ACR will open and reclose automatically in order to attempt to restore supply. If the fault is permanent, the ACR will lock open after a pre-set number of reclose operations (rural 2-3, elsewhere 1) and isolate the faulted section of line from the remaining system. ACR's do not replace feeder circuit breakers but are an additional protection device.

Figure 4-72: Single Line Diagram of Distribution Feeder



Due to the high cost of ACR's, all ACR's are protected by surge diverters on both sides of the device, irrespective of whether it is located at a normally open (N/O) or normally closed (N/C) point on the network. For details, refer to JEN PR 0011 HV OH Switchgear & Cable Head Pole Surge Arrester Installation and Earthing Procedure. Table 4-102 shows the number of in service ACR's on the JEN.

Table 4-102: Automatic Circuit Reclosers

Operating Voltage	2000-2002	2003-2005	2006-2008	2009-2011	2012-2014	2015-2018	2019-2021	2022-2024	Total
11kV	0	1	0	7	3	0	0	2	**13**
22kV	29	15	22	22	17	7	0	25	**137**
Total	**29**	**16**	**22**	**29**	**20**	**7**	**0**	**27**	**150**

4.13.2 ASSET PROFILE

4.13.2.1 *Life Expectancy*

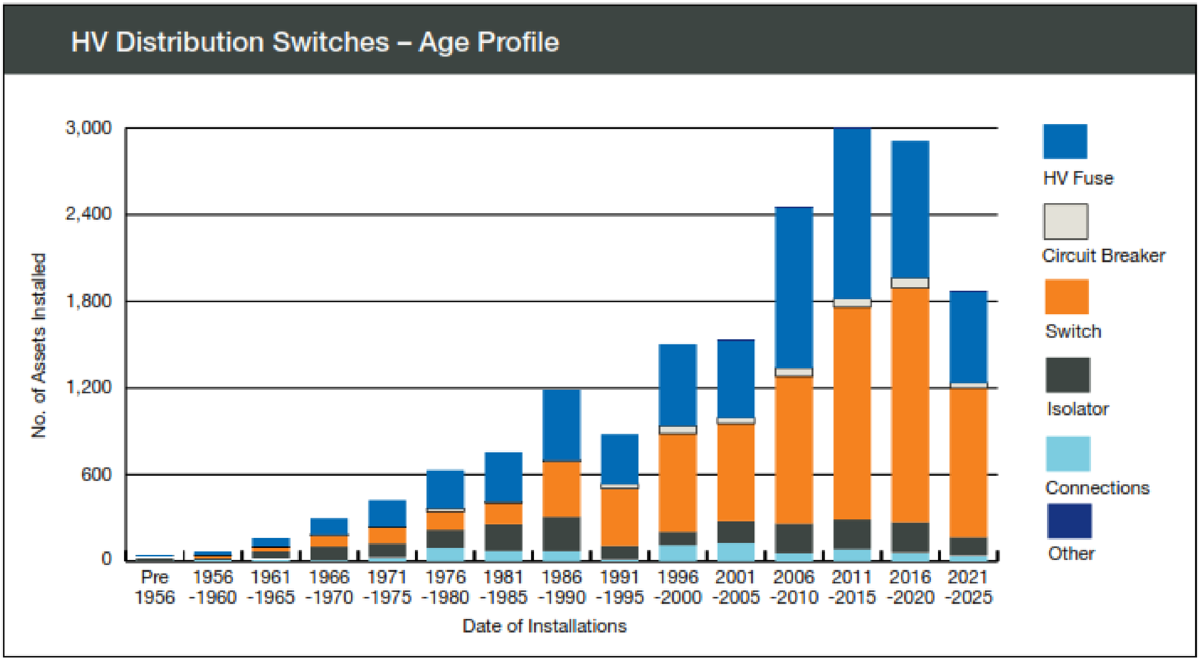
As detailed in ELE PR 0012 – Network Asset Useful Lives Procedure, the applicable useful life for overhead line switchgear assets is 50 years.

The above procedure considers asset lives based on good industry practice and specific JEN experience and represents the lives of assets at which end-of-life replacement will be considered. JEN has undertaken a number of reviews of asset useful lives with consulting agencies and held discussions with other Distribution Businesses to ensure assigned asset lives are realistic.

A number of ACR's have been replaced due to low SF6 gas pressure. These replacements are categorised as premature failures due to manufacturing defects and do not represent the typical life expectancy of an ACR.

4.13.2.2 *Age Profile*

Figure 4-73: HV Switches Age Profile



4.13.2.3 *Utilisation*

ACR's are utilised on the JEN as remote controlled sectionalising circuit breakers. They provide remote control and data acquisition capabilities to the JEN Control and Dispatch Centre and automate the protection of targeted HV feeder segments. Their deployment has resulted in significant improvement to the overall performance of the JEN in terms of a number of network reliability measures. In conjunction with remote controlled HV switches they have made a significant contribution to the automation of the JEN and have limited the impact of network outages on JEN's customers. The utilisation of these assets is very high. Typically, an ACR is not in service for a day or two every four years as a result of maintenance activities. Faults with battery alarms, communications etc. are generally rectified within a couple of days, however these faults do not require that the ACR be taken out of service.

4.13.3 PERFORMANCE

4.13.3.1 *Requirements*

Unless otherwise specified, Automatic Circuit Reclosers shall be designed, manufactured and tested in accordance with the following Australian Standards (refer to Table 4-103):

Table 4-103: Relevant Australian Standards – ACR's

Standard	Title
AS 62271.1	Common specifications for High Voltage AC Switchgear and Control Gear standards
AS 62271.100	High-Voltage Switchgear and Control gear – Alternating current circuit-breakers
AS 62271.200	High Voltage Switchgear and Control gear – AC Metal Enclosed Switchgear and Control gear for rated voltages above 1kV up to and including 52kV

The ACR's that are selected for use are designed and manufactured to achieve a service life of at least 50 years with minimum maintenance. The equipment must be able to operate within the required performance parameters when exposed to Victoria's climatic conditions.

W&B ACR's utilise vacuum interrupters for the arc interrupting process, and these are housed in a SF6 gas filled enclosure. This provides the insulation of the live parts in the body of the unit. W&B ACR's achieve a 150kV impulse withstand level at a pressure of 1.3bar (absolute).

NOJA ACR's similarly utilise vacuum interrupters for the circuit breaker function but these are housed in a solid dielectric which is enclosed in a metallic tank. The advantage that these offer is the fact that they are free of SF6.

4.13.3.2 *Assessment*

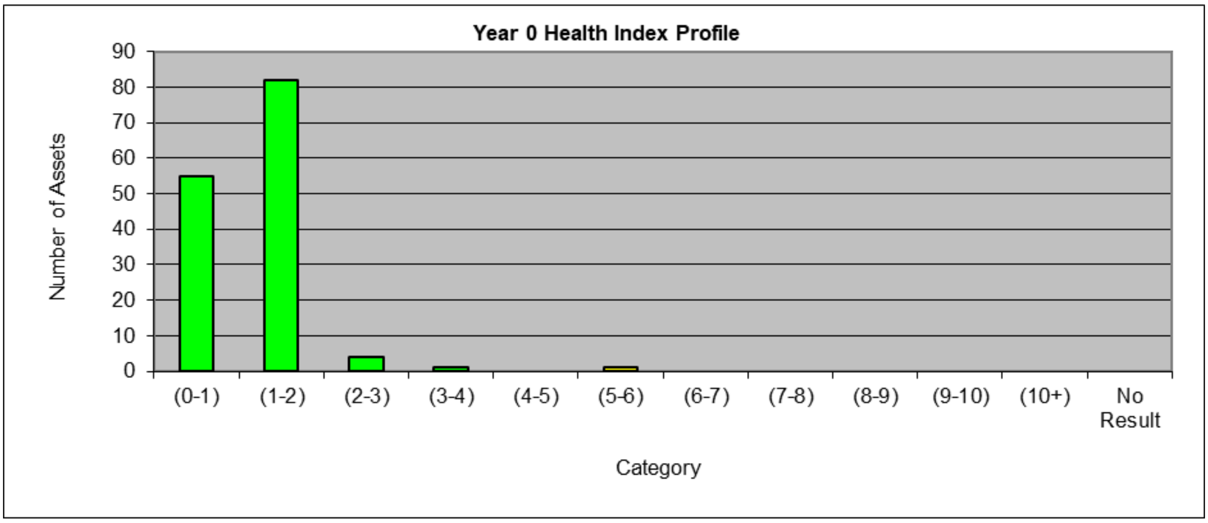
The performance of these assets is monitored via the asset inspection programs, both visual and infra-red. In addition, there is a degree of on-line monitoring of ACR condition via the SCADA system, this includes gas pressure monitoring of the W&B ACR's. Maintenance notifications are raised for any defect detected and these are used as inputs to the CBRM model.

4.13.3.2.1 CBRM Assessment – ACR's

The results of the CBRM modelling indicate that the current (Year 0) health index is as shown in Figure 4-74.

The total cost of risk for all failure scenarios at Year 0 is calculated to be $42k with a current predicted failure rate of 3 failures per annum. These failures can range from a minor failure, where maintenance work is required such as communications failure, to a major failure that includes replacement of the unit. The ACR's themselves have, to date, performed reliably with few significant failures.

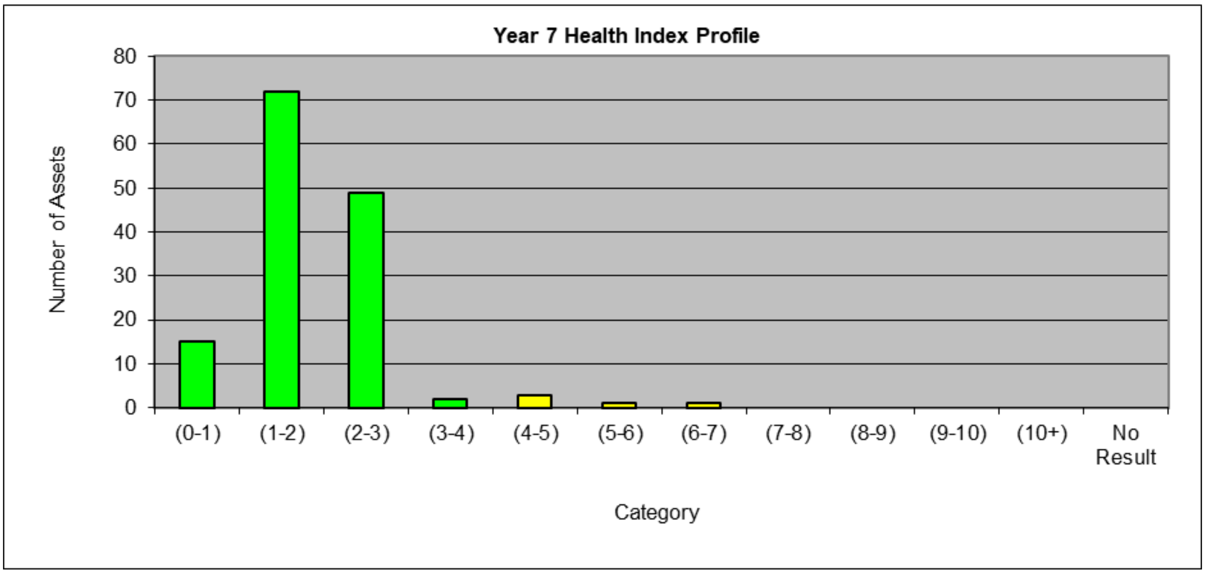
Figure 4-74: Year 0 Health Index Profile, ACR's



If asset replacement is deferred until 2031 (Year 7) the health index deteriorates slightly as indicated in Figure 4-75.

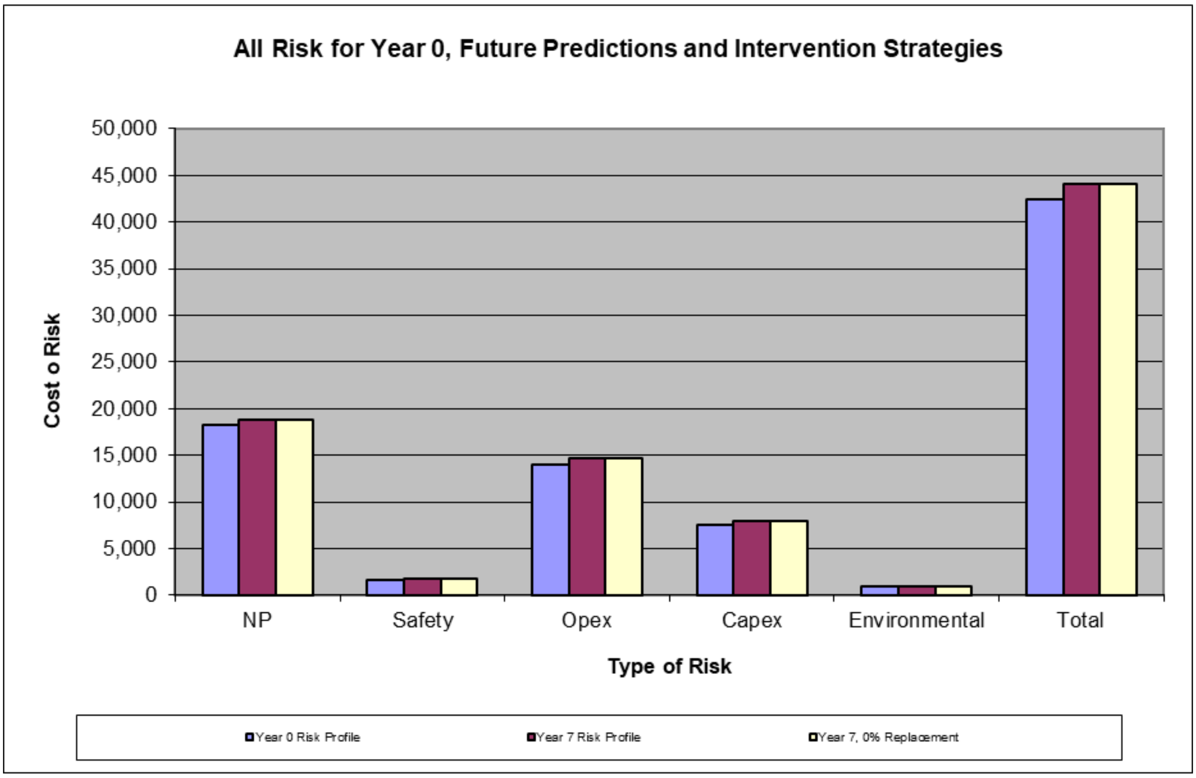
The total cost of the risk for all the failure scenarios at Year 7 is calculated to be $44k with a predicted failure rate of 3 failures per annum. That is there is no material change in the risk profile reflecting the young age of this group of assets.

Figure 4-75: Year 7 Health Index Profile, ACR's



ACR's are critical to the control and operation of the distribution network. The failure of an ACR affects the network's ability to isolate and recover from network outages. Consequently, the risk associated with the failure of an ACR is primarily related to the impact on network reliability as indicated in Figure 4-76. The CBRM modelling suggests that the risk of failure overall is very small, and this is reflected in the cost of the risk.

Figure 4-76: Risk Profile for Year 0 & Year 7, ACR's



The CBRM modelling indicates that no asset replacement is required over the next 7 years to maintain the risk profile at current levels. However, an allowance should be made for the replacement of one (1) ACR per annum over the coming 7 years to allow for failures associated with weather or other third party events such as vehicle impacts.

4.13.4 RISK

4.13.4.1 *Criticality*

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at sub-asset class level by following the JEN Asset Criticality Assessment Procedure (ELE-999-PR-RM-003, previously JEM AM PR 0016). . Results of this assessment are presented in Appendix A. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of JEN's operational objectives. This is used to rank importance of dissimilar sub-asset classes (e.g., transformers and buildings and grounds) to identify areas where risk should be managed first, and control measures implemented.

ACR's has an asset criticality score of AC1 (Low) due to the consequence rating being minor. Consequence of ACR failure may include SF6 gas leaks, cost of replacing failed/damaged asset and STPIS impact.

4.13.4.2 *Failure Modes*

There are several possible failure modes for ACR's which are summarised below:

- Fail to operate – either trip or close, possibly due to seized mechanism or worn components such as dry out capacitor on the tripping or closing circuit;
- Fail to interrupt – responds to signal but does not interrupt current, can be due to slow or incomplete operation, badly eroded contacts, ineffective insulation medium; could lead to thermal overheating and explosive failure;
- Fail to carry load – due to deteriorated or high resistance internal components; could lead to thermal overheating and explosive failure;
- Overheating- due to high resistance external connections/components; could lead to thermal overheating and damage;
- Insulation breakdown- internally, due to contamination or lack of SF6 or lightning impulse greater than LIWL rating, externally, bushing failure; and
- Auxiliary components failure- items such as auxiliary supply transformers, CTs protection relays, controllers, battery, radio and communication systems.

Whipp & Bourne (W&B) are the manufacturers of the majority of the ACR's installed on JEN currently. These ACR's employ vacuum interrupters for interrupting fault and load currents. The vacuum interrupters are housed in a controlled environment filled with SF6 gas. This gas facilitates the compact design of the ACR. All units are equipped with Schweitzer SEL electronic control relays.

With the exception of some issues with SF6 gas loss, these ACR's are generally very reliable devices with no evidence of field failure in the past.

The new NOJA ACR's employ vacuum interrupters housed in a solid dielectric. Little field experience has been gained at this stage, but the expectation is that these should also provide reliable service.

4.13.4.3 *Current Risks*

For details of the risk assessment of these assets refer to relevant section in JEN's Compliance and Risk System (OMNIA).

4.13.4.3.1 SF6 Gas Loss in W&B ACR's

SF6 gas pressure levels have been trending down in the fleet of in service W&B ACR's. W&B are aware of the loss of SF6 gas however, they have been unable to determine the cause of the leaks. As the SF6 is not associated with the arc interruption process, a minor reduction in SF6 gas pressure does not impact the reliable operation of the unit. The SF6 is required to achieve the voltage withstand performance of the ACR's. The SF6 gas pressure levels of all in-service W&B ACR's is monitored remotely via the SCADA system and maintenance notifications are raised by the control room to alert maintenance planners of a low gas condition. A W&B ACR will be replaced when the gas pressure falls to one atmosphere.

4.13.4.3.2 Sympathy Tripping

A small number of instances of sympathy tripping have occurred with the existing population of W&B ACR's. This has occurred where a feeder supplied from a zone substation bus common to a faulted feeder has incorrectly tripped due to the capacitive currents associated with underground cables. This is currently unavoidable as the protection systems fitted to the W&B ACR's are non-directional. Being non-directional the protection cannot differentiate between fault current flowing from a zone substation bus toward a fault through an ACR (a genuine fault) and capacitive currents from underground cable systems discharging back towards a zone substation bus that has suffered a voltage collapse due to a fault (sympathy tripping).

4.13.4.4 *Existing Controls*

Automatic Circuit Reclosers are inspected as part of the standard asset inspection program. All poles and lines in the HBRA are inspected every 3 years, and in the LBRA every 4 years. A thermal survey of ACR's is also performed as part of the regular overhead line thermal survey cycle to assist in the detection of potential failures before they occur.

On line condition monitoring of gas pressure levels and other alarm states such as battery health and auxiliary supply voltage occurs via the SCADA system. This is in addition to the monitoring and alarms associated with the protection systems.

4.13.4.5 *Future Risks*

The specification of future ACR's for use on the JEN needs to ensure that:

- Directional sensitive earth fault protection is included as this extra functionality will address the issue of sympathy tripping (refer to paragraph above); and
- The ACR does not utilise SF6 gas as this would eliminate the current maintenance issues associated with the gas loss and be consistent with JEN's desire to reduce the use of SF6 wherever possible given its properties as a greenhouse gas.
- AS 61850 is new standard communications protocol for the interface of power system elements and intelligent electronic devices (IED's) and is currently being evaluated prior to adoption on JEN. As such an AS 61850 compatible device will facilitate the future integration of these devices into a smart network.

4.13.5 LIFE CYCLE MANAGEMENT

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The aim is to achieve prudent and efficient operating expenditure and capital expenditure programs that manage the network risk and deliver improved safety outcomes that are associated with the replacement of unserviceable assets and the deployment of new technologies. The preferred asset lifecycle management option involves condition based replacement.

The strategy covers time based inspections followed by condition based maintenance and replacement, as well as in-service failure based reactive maintenance.

4.13.5.1 *Creation*

ACR's are deployed on JEN to facilitate the automation of the network and to maintain network reliability and address network performance issues. Installation of ACR's is driven by the identification and quantification of localised network reliability problems. They are sited so as to facilitate the sectionalisation of the HV network and to provide relief to underperforming parts of the HV distribution network. They are pole mounted devices where the majority of network faults occur and as such are an important part of the HV overhead distribution network.

4.13.5.2 *Asset Operation and Maintenance*

There are three (3) life cycle management strategies applied to the operation and maintenance of JEN's ACR's:

- Asset Inspection and Condition Monitoring;
- Preventative Maintenance; and
- Reactive and Corrective Maintenance.

A run to failure replacement strategy is not appropriate for ACR's as an in-service failure can have a large impact on network reliability and result in potential health and safety consequences.

4.13.5.2.1 Asset Inspection and Condition Monitoring

Inspection of ACR's is carried out as part of the standard asset inspection program. All poles and lines in the HBRA are inspected every 3 years, and in the LBRA every 4 years. A thermal survey of each ACR is also performed to assist in the detection of potential failures before they occur and is aligned with the regular overhead line thermal survey cycle.

For details of the activities involved in the asset inspection program, refer to the JEN MA 0500 - Asset Inspection Manual.

The gas pressure level for all in-service W&B ACR's is monitored remotely via alarms in the SCADA system.

ACR duty levels are also monitored. The vacuum interrupter's operating life is mainly dependent upon the number and magnitude of short-circuit operations. W&B estimates the life of the vacuum interrupter to be at least 20 years from the date of manufacture and the recommended maximum number of light load current switching operations to be 30,000. For details, refer to the manufacturer's manual.

The contact wear of the vacuum interrupter is calculated by accumulating the duty of the ACR which is remotely monitored, and an alarm is triggered in SCADA when it reaches 100%. The ACR's are not expected to reach their duty threshold during the operating life of the ACR.

4.13.5.2.2 Preventative Maintenance

4.13.5.2.2.1 Condition Based Replacement or Refurbishment

All ACR's are replaced based on condition as determined by inspection. In addition, W&B ACR's are replaced based on the monitoring of SF6 gas pressure. When a W&B ACR is found to have low gas pressure it is replaced with a spare ACR and the "low gas" ACR is returned to the manufacturer (if it is still under warranty - within 12 months) or inspected in the JEN workshop where the leak will be rectified before it is stored as a spare unit.

4.13.5.2.2.2 Proactive Replacement

There is no proactive condition based replacement of ACR's planned, as there are no known indicators of systemic or age related failure. There is, however, a plan to replace the protection systems associated with the ACR's so as to address the risk of sympathy tripping and implement directional sensitive earth fault protection on these devices. This may involve the replacement of the entire ACR rather than just the protection and control. The proposed volumes and associated capex are included in the forecast replacements listed below.

4.13.5.2.3 Reactive and Corrective Maintenance

As indicated above SF6 pressure levels in W&B ACR's are remotely monitored as part of condition monitoring. Where the gas pressure of an ACR has dropped below 1bar (absolute), the unit is replaced / swapped with a spare ACR, and the defective unit is taken to the JEN workshop and re-gassed.

W&B ACR's are fully enclosed and designed to be a maintenance free unit. With the exception of the SF6 gas loss, the ACR's are generally very reliable devices with no evidence of in-service failure in the past.

4.13.5.3 *ACR Forecast Replacement Volumes*

The forecast replacement volumes indicated in Table 4-104 are based on the output of the CBRM modelling and the maintenance of network reliability. In addition, the volumes associated with the implementation of directional protection and control systems are included.

Table 4-104: Forecast Replacement Volumes – ACR's

Unique ID	Service Code	Remote Controllable ACRs	Forecast Replacement Volumes						
			FY25	FY26	FY27	FY28	FY29	FY30	FY31
A469	RHH	ACR Replacement	-	-	6	6	6	6	6

4.13.5.4 *Asset Disposal*

Procedures for handling, storing and disposing of SF6 gas are detailed in accordance with JAM PR 0060 WI 16 – SF6 Gas – Identification, Storage, Handling and Disposal.

4.13.5.5 *Environment*

When decommissioning and removing assets it is important to assess the impact the JEN assets may have had on the environment. The JEN Environment Management Plan (ELE-999-PA-EV-010, Previously JEN PL 0061) has been developed to ensure that JEN's activities are undertaken consistently with minimal impact on the environment. This Plan applies to all personnel who are involved in the operation and maintenance of the electricity network, including capital and customer initiated projects.

4.13.5.6 *Spares*

The lead time to order a new ACR is approximately six months however there is a spare (refurbished) W&B ACR available at Tullamarine depot. The probability of an in service ACR failure is very low and there were only 4 failures over the population of 130 in the last 22 years due to direct lightning strike or animal strike.

4.13.6 INFORMATION

JEN's AMS provides a hierarchical approach to understanding the information required to achieve JEN's business objectives at the Asset Class level. The ACS provides the context for and determines the information required to manage and operate an Asset Class.

The Electricity Distribution ACS facilitates the safe, efficient and reliable delivery of electricity to JEN's customers.

From these business objectives, it is possible to identify at a high-level the content of the business information systems required to support these objectives (Table 4-105).

Table 4-105: Automatic Circuit Reclosers Sub-Asset Class Business Objectives and Information Requirements

Business Objectives	JEN Information Sources	Externally Sourced Data
Operational Excellence • Manage assets throughout their lifecycle in safe and environmentally responsible manner • Maintain assets in accordance with RCM principals • Maintain asset information/knowledge to enable efficient and effective decision making • Embed continuous improvement throughout asset lifecycle **Customer** • Maintain our current service levels • Incorporate customer feedback in our decision making process **Growth** • Acquire/install/maintain assets to meet future demand requirements **People** • Maintain safe work environment • Engage team leaders in assessment of new assets • Training	**GIS/JEN Viewer** • Geospatial representation of the JEN Network • Asset attributes **SAP** • Work schedule & status • Planned and corrective (faults) maintenance records • Asset inspection measurements • Financial information **ECMS** • Asset Inspection Manual, inspection methods & criteria • Policies, procedures and guidelines • General asset audits/surveys not stored in SAP • Incident investigations **Drawbridge** • Standards • Operations diagrams • Line design manual • Construction manual • Asset photographs **SCADA/RTS** • OMS & SCADA (DMS) • Planned and Unplanned outages **JEN Analytics** • Power quality data • Energy consumption	• Current cadastre (including land ownership) for JEN's geographical extent. • **DEECA** - HBRA and LBRA area boundaries • **CFA** for fires, warnings and restrictions, incidents • Emergency Management Common Operating Picture (**EM-COP**) • Aerial Imagery for JEN's geographical extent (NearMap) • Google 'Street View' • Melway • **Intertek Inform i2i** (Australian and International Standards) • **ESV / ESC / AER** for regulatory obligations

Table 4-106 identifies the current and future information requirements required to support the critical decision making for the Asset Class and the value of the information to the Asset Class.

Table 4-106: Automatic Circuit Reclosers Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Automatic Circuit Recloser acquisition and application	• Purchase specification (ECMS) • Distribution Design Manual (ECMS) • Distribution Construction Manual (ECMS) • Period contracts (ECMS) • Logistics system (SAP)		• **High** – strict control of the quality of supplied ACR's and detailed, repeatable installations appropriate to application.
Lifecycle Management • Asset identification • Condition monitoring • Condition assessment • Replacement / retirement strategy • Disposal	• Each asset identified by geospatial representation in GIS and equipment ID in SAP • Asset Inspection Manual (ECMS) • Maintenance plan (SAP) • JEN Analytics (e.g., deteriorated neutral) • Measurement record (SAP / ECMS) • PM Notifications/Orders (SAP) • Strategy detailed in this document • GIS asset attributes: - Asset status (e.g., existing/historical) - Status (in service, isolated, out of commission) - Type/Manufacturer - Switch No. - Operating State - Normal State - Physical Location (Melway reference, closest address / intersection) - Operational Tag - Controller Type • Fault / failure records: - Root Cause • Performance trends (shared network drive) • Customers impact • Maintenance costs (SAP) • Disposal Procedure	• Near real time updating of asset record • Photos database of all failed assets • Appropriate fault/failure data by failure mode (e.g., material degradation, age, workmanship, third party etc)	• **High** – allows more accurate, efficient management of assets through performance trends and cost monitoring

Table 4-107 details the information initiatives required to provide the future information requirements identified in Table 4-106. Included within this table is the risk to the Asset Class from not completing the initiative.

Information required to support asset strategies, performance and risks is recorded in SAP, GIS and ECMS. Additional fault related data is available in the OMS. Data from SAP can be extracted and analysed using SAP Business Objects.

Table 4-107: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Improved asset information	Field collection of incomplete asset attribution and assets	High	Complete, Current, Attribution Accurate
Network Performance Data	Ability to 'view' asset performance data from the GIS user interface or access an asset's historical performance data.	Medium	Complete, Current, Attribution Accurate, Consistent (GIS Asset ID to SAP Asset ID)
Improved Asset Attribution	Review of asset attribution fields to ensure attributes being collected are business specific	Medium	Attribution Accurate
Increased Timeliness	Latency between maintenance delivery and maintenance record capture decreased	High	Complete, Current, Attribution Accurate

5 CONSOLIDATED PLAN

5.1 ASSET INVESTMENT PLAN

The Asset Investment Plan (AIP) provides a snapshot of how JEN will be managed to achieve its AMP objectives and consequently JEN's strategic objectives. It also outlines the key asset strategies supporting JEN's goals and objectives and informs the proposed expenditure plans and programs of work. The purpose of the AIP is to:

- Detail the investment plan for the next seven years for the operating expenditure and capital expenditure programs of work including the drivers for expenditure, current issues and the strategies for managing current issues; and
- Outline the current and emerging financial risks and opportunities impacting on JEN and describe how JEN is positioned to mitigate or take advantage of the identified risks and opportunities.

The AIP defines the nature of the works to take place to manage JEN within the constraints of cost and risk whilst at the same time maintaining current levels of network reliability and safety. A high level view of program deliverables is provided that encompasses the major projects to be delivered to ensure supply security for our customers is maintained.

It also contains the rationale for asset management activities, operational and maintenance plans and capital investment (overhaul, renewal, replacement and enhancement) plans.

5.2 CAPITAL AND OPERATIONAL WORK PLAN

The Capital and Operational Work Plan (COWP) contains details on optimised capital and operational expenditures over a two-year period. It aggregates the required actions emanating from the JEN Asset Management Plan (AMP) and various Asset Class Strategies (ACS).

The COWP aids the development of the JEN Delivery Plan, the purpose of which is for Service Providers to critically evaluate field resource availability with the program of work required to be delivered. Refer to Figure 1-2 for the JEN AMS, which identifies where the COWP is positioned within the AMS document hierarchy.

6 GLOSSARY

6.1 ZONE SUBSTATION ABBREVIATIONS

Substation	Suburb	Substation	Suburb
AW	Airport West	HB	Heidelberg
BD	Broadmeadows	MAT	Melbourne Airport
BKN	Brooklyn	NEI	Nilsen Electrical Industries
BMS	Broadmeadows South	NEL	North East Link
BY	Braybrook	NH	North Heidelberg
CBN	Craigieburn North	NS	North Essendon
CN	Coburg Nth	NT	Newport
COO	Coolaroo	PTN	Preston
CS	Coburg South	PV	Pascoe Vale
EPA	East Preston A	SBY	Sunbury
EPB	East Preston B	SHM	Sydenham
EPN	East Preston	SSS	Somerton Switching Station
ES	Essendon	ST	Somerton
FE	Footscray East	TH	Tottenham
FF	Fairfield	TMA	Tullamarine Airport
FT	Flemington	VCO	Visy Board
FW	Footscray West	YVE	Yarraville

7 APPENDICES

7.1 APPENDIX A – ASSET CRITICALITY ASSESSMENT

ASSET CRITICALITY ASSESSMENT WORKSHEET

ASSET AND BACKGROUND INFORMATION	
Site Name	**General**
Asset Class	**Electricity Distribution**
Sub-Asset Class	**All**
Date of Original Assessment	**15-May-18**
Date of Last Review	**17-Dec-24**
Reviewed By (where applicable):	**Catherine Lee (Principal Asset Performance Engineer)**

Risk Ref. No.	Description of Asset or Asset Grouping	Description of Risk	Consequence Category (Operational, HSE, Reputation etc.)	Description of Consequence and Likelihood	Current Controls	Criticality Score	Criticality Rating
1	Earthing Systems	The risk of electric shock to internal employees, contractors or the public caused by inadequate pole distribution substation HV earthing system (i.e. high resistance earth, step & touch potential under fault conditions, non-operation of HV protection)	HSE	**Major** due to potential life-threatening injuries to staff, contractors or member(s) of the public Likelihood: Possible due to a chance that it could happen in the next 5 years and increasing incidence of theft.	As per ACS	AC4	High
2	Conductor (switch wire)	The risk associated with accidental connection with switch wire, resulting in safety hazard to (public or employee), loss of supply and/or shocks	HSE	**Major** due to potential for: • Total permanent disability (staff or contractors) • Multiple hospitalisations, permanent disability and/or life threatening injuring members(s) of the public • Electrocution Likelihood: Rare due to absence of incidents within the last 10 years.	As per ACS	AC4	High
3	Underground Cable	The risks associated with underground cable records not updated or recorded accurately in GIS or Dial Before You Dig (DBYD) to reflect current condition, resulting in third-party dug-ups.	Regulatory & Compliance / Financial	**Severe** due to: • Moderate stakeholder concern / interest • Regulator requires formal explanations & remedial action plans Likelihood: Possible due to: • 26-50% probability of occurrence (might occur at some time within the next 5 years) • History on the JEN network for these type of incidents to occur	As per ACS	AC3	Significant
4	Overhead Service Line	Broken neutrals in services cables or mains neutrals	HSE	The risk associated with broken neutrals in services cables or mains neutrals, resulting in: • Electrocution • Minor shock • Flashover • Damage to third party property **Major** due to potential for: • Total permanent disability (staff or contractors) • Multiple hospitalisations, permanent disability and/or life threatening injuries affecting member(s) of the public Likelihood: Unlikely due to: • Lack of incidents occurring on JEN network within the last 10 years • Event could occur at some time within the next 10 years	As per ACS	AC4	High

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ASSET CRITICALITY ASSESSMENT WORKSHEET

ASSET AND BACKGROUND INFORMATION	
Site Name	General
Asset Class	Electricity Distribution
Sub-Asset Class	All
Date of Original Assessment	15-May-18
Date of Last Review	17-Dec-24
Reviewed By (where applicable):	Catherine Lee (Principal Asset Performance Engineer)

Risk Ref. No.	Description of Asset or Asset Grouping	Description of Risk	Consequence Category (Operational, HSE, Reputation etc.)	Description of Consequence and Likelihood	Current Controls	Criticality Score	Criticality Rating
5	Pole Top	Crossarm failure (assisted / unassisted)	Operational / Health & Safety	**Minor** due to a feeder outage for less than 6 hours (note: it is possible to replace a crossarm within 6 hours) Minimal impact on health and safety of staff, contractors or member(s) of the public Likelihood: Almost Certain because JEN has a history of unassisted in-service crossarm failures annually.	As per ACS	AC1	Low
6	Distribution Substations (Pole Type / Non-Pole Type)	The risk of distribution substation equipment failure or damage e.g. distribution transformer or switchgear failure resulting in damage to assets, fires, third party property, medical treatment or lost time injury	HSE	**Serious** due to: • Medical treatment injury or lost time injury (staff or contractors) • On-site first aid to a small number of member(s) of the public Likelihood: Possible as the event will probably occur at some time within the next 5 years	As per ACS	AC2	Moderate
7	Pole (Steel / Concrete)	Conductive pole becoming live	HSE	**Major** due to: • Hospitalisations, permanent disability and/or life-threatening injuries affecting member(s) of the public Likelihood: Rare due to <5% probability of occurrence	As per ACS	AC4	High
8	Overhead Line Switchgear	Switch Failure	Operational	**Minor** due to a feeder outage for less than 6 hours (note: it is possible to replace a switch or reconfigure the network within 6 hours) Minimal impact on health and safety of staff, contractors or member(s) of the public Likelihood: Likely because JEN has a history of switch failures Across each of the 222 zone substation feeders on the JEN, of which each feeder supplies an average of 1,702 customers, each feeder has an average of 4 air break switches, 10 sets of isolators and 5 gas switches; therefore a failure to operate, or loss of communication (remote controlled switch), can adversely affect the ability to operate the network and potentially impact 85 customers.	As per ACS	AC1	Low

ASSET CRITICALITY ASSESSMENT WORKSHEET

ASSET AND BACKGROUND INFORMATION	
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Date of Last Review	**17-Dec-24**
Reviewed By (where applicable):	**Catherine Lee (Principal Asset Performance Engineer)**

Risk Ref. No.	Description of Asset or Asset Grouping	Description of Risk	Consequence Category (Operational, HSE, Reputation etc.)	Description of Consequence and Likelihood	Current Controls	Criticality Score	Criticality Rating
9	HV Fuse	The risk associated with the candling of fuses, resulting in overheating, explosion, maloperation, fire, damage to property and/or minor injury.	HSE	**Minor** due to: • JEN equipment damage under $100k (metal clad switchgear) • Minimal impact on health and safety of staff, contractors or member(s) of the public Likelihood: Possible due to similar incidents having occurred within the last 5 years.	As per ACS	AC1	Low
10	Surge Arrester	Surge arrestor failure/damage	Financial	**Minor** due to: • JEN equipment damage under $100k • Public safety to people through shattered porcelain associated with explosive failure and external liability due to litigation claims for property damage and personal injury. Likelihood: Unlikely, JEN has previous history with one incident within 10 years.	As per ACS	AC2	Moderate
11	ACR	ACR failure/damage.	HSE	**Minor** due to: • Environmental impact due to SF6 gas leak • Replacement of equipment is under $100k (excludes STPIS) Likelihood: Likely due to JEN has history of gas leaks on some of the ACRs with gas pressure slowly trending down.	As per ACS	AC1	Low
12	Public Lighting	Public lighting lantern failure	Financial	**Minor** due to: • Replacement of equipment significantly less than 100k Likelihood: Almost Certain, there is previous history of public lighting lantern failing within JEN every year.	As per ACS	AC1	Low
13	Grounds/Buildings	Failure to maintain non-pole substation grounds	HSE	**Major** due to potential life-threatening injuries as a result of equipment failure` Likelihood: Unlikely, due to a chance that it could happen in the next 10 years	As per ACS	AC3	Significant