STRATEGY

ELECTRICITY PRIMARY PLANT ASSET CLASS STRATEGY

ELE AM PL 0061

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AUTHORISATION

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INTERNAL

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DOCUMENT HISTORY

Revision	Date	Author	Description of Changes
00	30/08/2017		Combined ZSS ACS into one document & enhanced to new template Combined ZSS ACS into one document & enhanced to new template
1	02/07/2018		Updates and additions to address Information, Risk, Spares and Criticality definition. Executive summary updated. Transformers and other sections amended to standardise and correct content. CBRM updated to reflect ZSS NS and ZSS P updates.
1.1	16/11/2018		General update. Update of all the asset data, graphs and CBRM information. Addition of JEN Zone Sub addresses.
1.2	1/4/2019		General Updates following external review
1.3	30/10/2019		General Updates following second external review
2	20/12/2019		Updated Executive Summary
2.1	30/12/2019		Section 1, 2, 3 condensed, and 5 updated

OWNING FUNCTIONAL GROUP & DEPARTMENT / TEAM

Asset Management : Asset Strategy : Primary Plant

REVIEW DETAILS

Review Period:	1 year
Next Review Due:	September 2020

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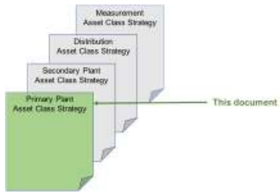
EXECUTIVE SUMMARY

Jemena Electricity Networks (JEN) in Victoria has an Asset Management System (AMS) that contains a set of four Asset Class Strategy (ACS) documents. The ACSs are hierarchically governed by the Asset Business Strategy (ABS) of the AMS.



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

This ACS document pertains to Electricity Primary Plant, a term that denotes a range of equipment that is used in zone substations.

The first three sections of this ACS are generic to all the ACS documents. The fourth section is where the Electricity Primary Plant is unpacked and divided into zone substation sub-asset classes

- Transformers
- Circuit breakers
- Disconnectors and buses
- Instrument transformers
- Capacitor banks
- Buildings and grounds
- Earthing systems

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

In line with standard risk assessment, asset functional failure is a combination of probability and consequence. All the documented asset management strategies focus on keeping the probability of failure to a low level. This means using CBRM to achieve end-of-life asset replacement before serious failures occur.

The financial forecasts form the key findings of this ACS. This capital expenditure (CAPEX) and operational expenditure (OPEX) data informs the business and is shared, in commercial confidence, with the Australian Energy Regulator (AER) as part of the Electricity Distribution Price Review (EDPR) determination. Further detail is provided in Section 5 Consolidated Plan, Capital Forecast.

CapEx and OpEx forecasts

CAPEX $000	2020	2021	2022	2023	2024	2025
Transformers	$3,819	$7,320	$2,610	$36	$36	$228
Circuit Breakers	$6,647	$6,941	$1,397	$5,494	$3,081	$5,789
Disconnectors and Buses	$-	$509	$330	$188	$-	$192
Instrument Transformers	$-	$-	$-	$-	$-	$-
Capacitor Banks	$-	$12	$12	$963	$12	$12
Buildings and Grounds	$521	$667	$942	$1,073	$619	$363
Earthing Systems	$-	$281	$62	$283	$64	$288
Miscellaneous	$58	$621	$358	$840	$379	$641
Total	**$11,045**	**$16,351**	**$5,711**	**$8,877**	**$4,192**	**$7,512**

Forecast OPEX Expenditure ($ '000)

SAP Code	Description	2020	2021	2022	2023	2024	2025
MPA	Zone Substation Property Maintenance	$167	$171	$175	$180	$184	$189
MPB	Zone Substation Property Maintenance Defects	$86	$88	$90	$93	$95	$97
MZA	Zone Substation Equipment Maintenance - Primary	$983	$1,008	$1,033	$1,059	$1,085	$1,112
MZC	Zone Substation Defect Maintenance - Primary	$314	$322	$330	$338	$347	$355
MZI	Zone Substation Inspection and Audits	$145	$149	$152	$156	$160	$164
FZA	Zone Substation Primary Faults	$24	$25	$25	$26	$26	$27
	Total	**$1,719**	**$1,763**	**$1,805**	**$1,852**	**$1,897**	**$1,944**

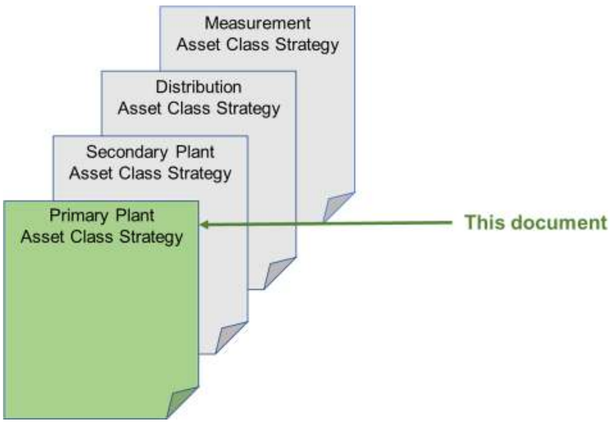
1 INTRODUCTION

This Asset Class Strategy (ACS) covers the Jemena Electricity Networks (JEN) primary plant asset class and outlines the methods employed, analysis undertaken and actions to be taken to optimally manage the assets. The document serves as both an internal document to prescribe the management of the primary plant asset class but also to support expenditure proposals as part of JEN's electricity distribution price reset (EDPR) submission process.

Within JEN's Investment Framework and Asset Business Strategy (ABS), asset life cycles are considered in terms of creation (acquisition), maintenance or replacement, as applicable, and disposal. Investment recommendations are made by analysing asset condition and age profiling.

There are four Asset Class Strategy (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 - There are four ACS documents incorporated into JEN's Asset Management System



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

- 4.1 Transformers, including station service transformers, Neutral Earthing resistors (NER),and Rapid Earth Fault Current Limiter (REFCL);
- 4.2 Circuit breakers, both outdoor and indoor switchboards;
- 4.3 Disconnectors and buses (outdoor) including earthing switches and surge arresters and connections to assets;
- 4.4 Instrument transformers (outdoor stand-alone types) CTs & VTs;
- 4.5 Capacitor banks including earthing switches and instrument transformers within the banks;
- 4.6 Buildings and grounds, including structures, yard facilities, drainage, bunding, security fences & walls; and
- 4.7 Earthing system, earth grid and connections

1.1 PURPOSE

The purpose of the Electricity Primary Plant ACS is to document the practical approach that supports the delivery of asset management objectives set out in the JEN's ABS.

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.

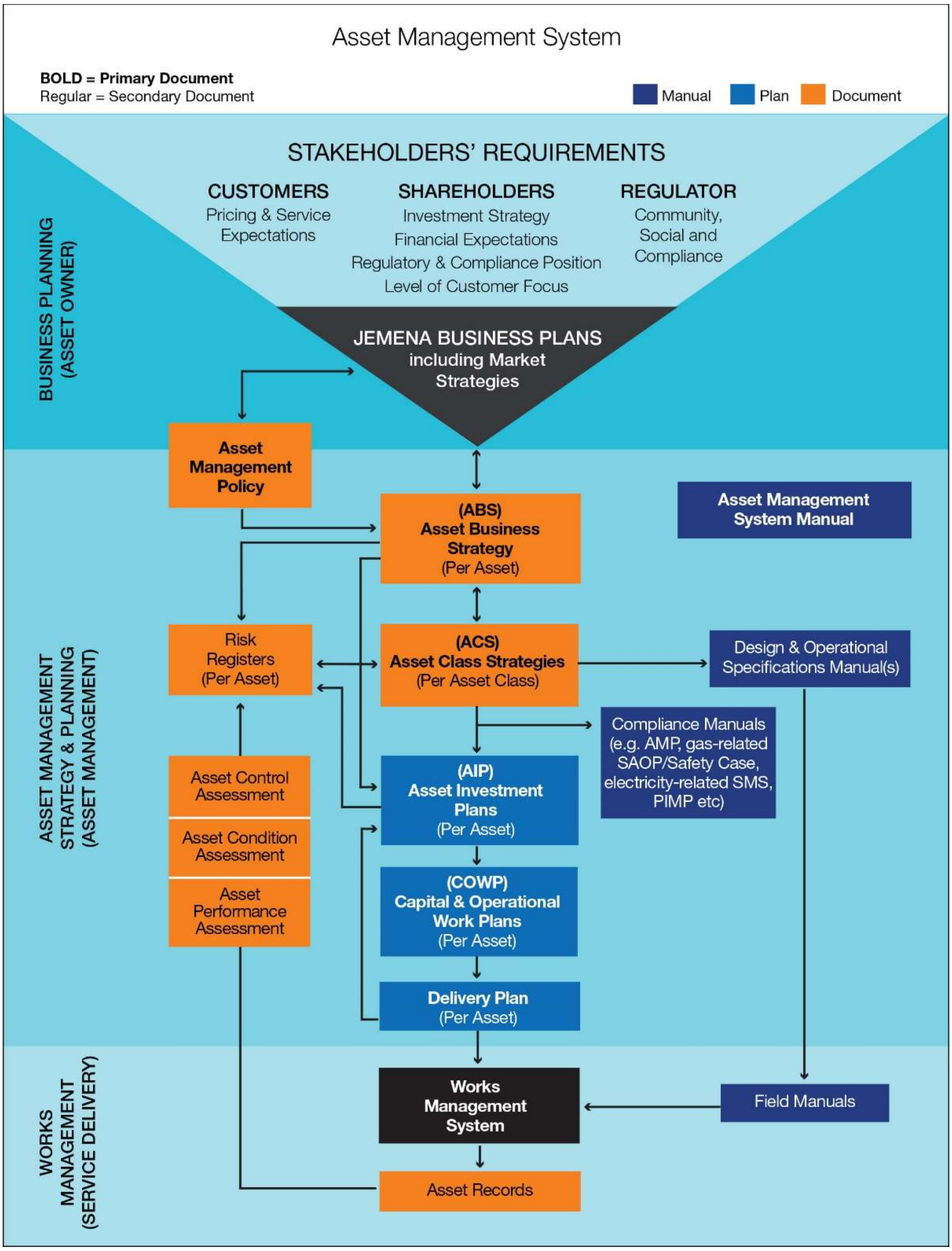
This primary plant ACS addresses:

- Primary 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 (OPEX) and Capital Expenditure (CAPEX) planning

1.2 ASSET MANAGEMENT SYSTEM

The ACS documents reside in JEN's Asset Management System (AMS) and creates a line of sight between the Business Plan and JEN's ABS through to the associated Asset Management Plan (AMP). Each 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 2 – JEN's Asset Management System



1.3 DESCRIPTION OF ASSETS COVERED

The regulatory standard life set by the AER, for distribution system assets, is 49.5 years. The Tax Asset Life set by the ATO, for distribution system assets is 40 years. In the context of these asset lives, Jemena has assessed that the expected nominal life of primary plant assets is 50 years. This can be seen as a peak in the number of assets installed around this period. 31% of transformers and 20% of circuit breakers are 50 years or older. Similarly, 72% of disconnectors, 16% of instrument transformers and 18% of capacitor banks are beyond 50 years of age.

Figure 3 – JEN's geographical footprint

The JEN operates 26 zone substations and 4 HV customer substations with JEN assets installed[1]. These substations are equipped with:

- 65 power transformers ranging in age from 1 to 69 years of two main types; 66kV primary voltage and secondary voltages of 22kV, 11kV or 6.6kV, and 22kV primary voltage and secondary voltages of 11kV or 6.6kV;
- 491 circuit breakers ranging in age from 0 to 81 years, comprising; 65 – 66kV CBs, 276 – 22kV CBs, 93 – 11kV CBs and 57 – 6.6kV CBs. The 66kV and 22kV CBs are installed in a mix of indoor and outdoor environments; with all the 11 and 6.6 kV CBs being indoor;
- 844 disconnectors, isolators and earth switches ranging in age from 3 to 63 years and 119 outdoor buses ranging in age from approximately 2 to 62 years;
- 231 Current and Voltage transformers ranging in age from approximately 1 to 63 years of voltages 66 and 22 kV;
- 38 capacitor banks ranging in age from approximately 3 to 56 years; and
- 26 zone substations and 4 HV customer substations with JEN assets installed with building and other physical infrastructure ranging in age from 2 to 63 years.

[1] Refer to Appendix K for a list of JEN zone substations and HV customer substations with Jemena assets installed.

1.4 GOVERNANCE

1.4.1 APPROVAL AND COMMUNICATIONS

Asset Class Strategy documentation is updated annually by the Asset Engineering Manager for approval by General Manager Asset Management Electricity Distribution

The Asset Class Strategy is reviewed annually 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

Job Title	**Responsibility**
GM Asset Management Electricity Distribution	Approval
Asset Engineering Manager	Document Owner
Principal Primary Plant Engineer	Primary Plant Responsible Asset Manager
Senior Primary Plant Engineer	

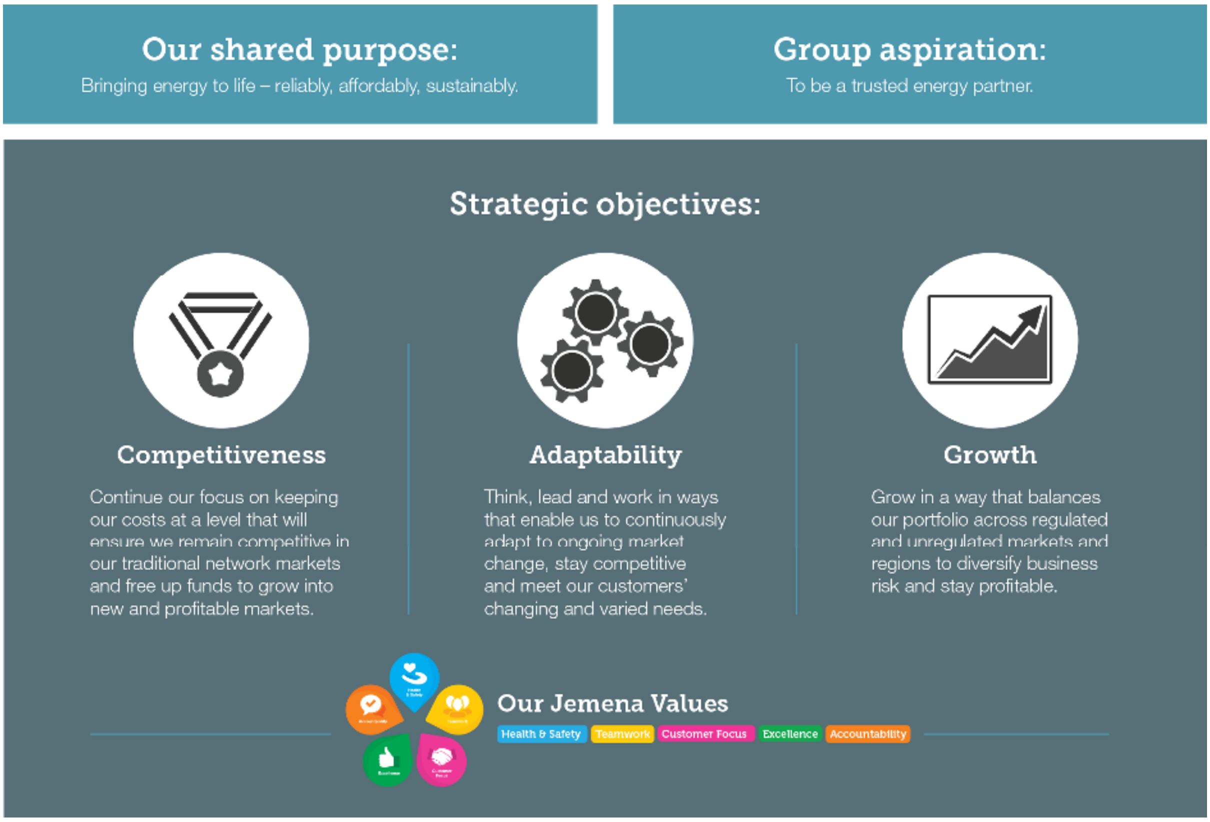
2 STRATEGIC DRIVERS

The ABS (2019) states the asset management strategic drivers are

- Market and competitive position, future growth, demand and customer connections
- Customer and community expectations (service levels)
- Stakeholder expectations
- Regulation and legislative environment
- Asset management capabilities (processes, systems, resources, knowledge)
- Technology
- Other drivers relevant for the asset such as climate change

Combined, these strategic asset management drivers ensure JEN optimises the condition, performance and associated costs over the life of each asset.

Figure 4 – Jemena's high level strategic goals informs the ABS



2.1 GROWTH

The coming 20 year period for the electricity network holds significant uncertainty. Customer behaviours are changing with the advent of new technologies which have the potential to reduce the need for the network as a source of supply, while at the same time, the demand for supply quality and growth in customer connections continue to rise. These two forces act against one another. JEN's expected position entering the next regulatory reset period is that demand growth, network wide, will continue at a similar rate as the last regulatory reset period. That stated, there are areas within the network where maximum demand growth is forecast well beyond the network average level while other parts of the network are forecast to experience reductions in maximum demand as a result, for example, of manufacturing closures. Analysis is ongoing and JEN's ABS will evolve as new insights emerge. JEN's ABS contains the ten year forecast which the business is working to. JEN is actively monitoring several dynamics which impact this forecast. Refer to the JEN ABS for further details.

2.2 STAKEHOLDERS

2.2.1 CUSTOMERS

Decision making on behalf of customers involves trade-offs. For example, our customers consistently tell us they value a safe, reliable and responsive supply of electricity. But they also tell us that rising energy prices have become a concern. These priorities are mixed, as higher service levels involve higher costs. It is a 'trilemma'

JEN's ABS states,

> *'The community expects environmental responsibility; a safe and reliable level of service; a responsive service; public amenity; equitable levels of service available to all consumers; and affordable pricing.'*

2.2.2 SHAREHOLDERS

Asset procurement and operation must support the network's ability to produce and sustain profitability for shareholders.

JEN's ABS states,

> *'Our asset management decisions need to take into account the certainty our shareholders have about recovering their significant up-front investment in the asset.'*

2.2.3 INTERNAL

Each ACS relies upon the contributions of several areas of the business. Stakeholders have business and operational insights that contribute to the effectiveness of the asset management. There are also reporting requirements back into the business. Section 1.2 *Asset Management System* maps stakeholder requirements.

2.3 REGULATORY AND LEGISLATIVE

JEN meets legal, licence and regulatory obligations so as to comply with the National Electricity Rules (NER) mandated by the Australian Energy Market Commission (AEMC) together with other rules, codes and guidelines set forth by the:

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

The JEN ABS describes how the business complies with the requirements of each of these stakeholders in order to retain its distribution licence, adhere to the NER and meet safety obligations. There are perennial 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 OBJECTIVES

JEN's objectives

> *…provide the essential link between key strategic objectives which support the Group strategy and the JEN asset management plan that describes how the objectives are going to be achieved. The asset objectives transform the required outcomes (product or service) to be provided by JEN, into activities typically described in the JEN asset management plan. This in-turn provides the line of sight for asset management activities.*

Asset Class Strategy objectives are:

- The practice of a 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 contains deterioration in service levels;
- Optimise asset life cycle. Defer asset replacement expenditure by use of 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 minimises the design and life cycle costs of assets installed. For instance, standardisation of specifications for purchasing of primary plant assets together with the construction of zone substation physical assets and facilities, achieves efficiencies. These co-ordinated and integrated designs are particularly focused on attributes of robust long life, security, reliability and cost effectiveness.

A table assigning KPI's to the above objectives and aligning them to the ABS is located at Appendix M.

Figure 5 - There are five key success measures and objectives

4 SUB ASSET CLASS STRATEGIES

4.1 ZONE SUBSTATION TRANSFORMERS

This sub-class covers Zone Substation Transformers, including major components, 66kV bushings, on-load tap changers; plus Neutral Earthing Resistors (NERs), Rapid Earth Fault Current Limiters (REFCL) and Station Service Transformers.

4.1.1 INTRODUCTION

The function of power transformers installed in Zone Substations is to transform sub-transmission voltage (66 or 22kV) to the distribution voltage (22, 11 or 6.6kV) used in the local area HV distribution network. The regulation of the distribution voltage at the zone substation bus is achieved by on load tap changers (OLTC) installed on or in the transformers. 66kV bushings provide an insulated connection between bare overhead conductors and internal primary winding of the transformer. Distribution voltage connections are achieved either by HV outdoor bushings or HV cable box.

To limit the phase-to-earth fault current level, Neutral Earthing Resistors are installed between the transformer neutral connection and the ZSS earth grid.

In Hazardous Bushfire Risk Areas (HBRA's), to quickly reduce and phase-to-earth faults to very low energy levels, a Rapid Earth Fault Current Limiter (REFCL) may be installed also.

Station Service transformers are connected to the HV distribution bus or feeder to provide an LV supply to the substation LV light and power requirements including battery chargers for the DC system supplying protection, control and communication equipment needs.

This section includes information about the type, specifications, life expectancy and age profile of the power transformers in service across the Jemena Electricity Network (**JEN**).

The JEN operates 26 zone substations and 4 HV customer substations with Jemena assets installed[2]. These substations are equipped with 65 power transformers of two main types:

- 66kV primary voltage and secondary voltages of 22kV, 11kV or 6.6kV, depending on their geographical location; and
- 22kV primary voltage and secondary voltages of 11kV or 6.6kV

An urban zone substation typically has two or three 20MVA naturally-cooled transformers (potentially increasing to 33MVA when fitted with fans and pumps) with some transfer capacity between adjacent zone substations. In *a few* areas, smaller 12/18MVA transformers have been used.

Typically, a zone substation equipped with three power transformers supplies between eight to twelve distribution feeders and in excess of 10,000 residential customers.

Equipment critical to power transformer operations includes on-load tap-changers (**OLTC**), neutral earthing resistors, Rapid Earth Fault Current Limiters (REFCL) and station service transformers.

A particular critical transformer component is 66kV bushings due to some history of failure and catastrophic consequences such as fires destroying the total transformer. The JEN network has 62 power transformers which utilise 66kV bushings (183 in total) at 24 zone substations.

There are three main types of 66kV transformer bushings:

[2] Refer to Appendix K for a list of JEN zone substations and HV customer substations with Jemena assets installed.

- Synthetic Resin Bonded Paper (SRBP);
- Resin Impregnated Paper (RIP); and
- Oil Impregnated Paper (OIP)

The old State Electricity Commission of Victoria (SECV) standardised SRBP 66kV bushings for all power transformers manufactured prior to 1980.

4.1.2 ASSET SPECIFICATION

Table 4-1Error! Reference source not found. lists the population, voltage ratio, ratings and year of manufacture for this asset class. Zone Substation (ZSS) AW and BD have 4 high rating transformers (30MVA to 40MVA) installed, whereas TH has only 2 of the highest rating transformers (45MVA) installed. ZSS FF and NT transformers are the oldest on the network.

Table 4-1: Power Transformer Information

Zone Substation	Voltage Ratio	NER	Transformer MVA Capacity (Year of Manufacture)							
			1		2		3		4	
AW (Airport West)	66/22kV	Y	20/30	(1966)	20/30	(1981)	20/30	(1966)	20/40	(1988)
BD (Broadmeadows)	66/22kV	Y	20/30	(1973)	20/30	(1968)	20/30	(1968)	20/33	(2002)
BMS (Broadmeadows South)	66/22kV	Y	20/33	(2014)	20/33	(2014)				
BY (Braybrook)	66/22kV	Y	20/30	(1967)	20/33	(2006)				
CN (Coburg North)	66/22kV	Y	20/30	(1967)	20/30	(1967)	20/33	(1990)		
COO (Coolaroo)	66/22kV	Y	20/33	(2007)	20/33	(2012)				
CS (Coburg South)	66/22kV	Y	20/33	(1976)	20/33	(1976)				
EP (East Preston)	66/6.6kV	N	20/27	(1962)	20/27	(2006)	10/13	(1959)	10/13	(1958)
EPN (East Preston)	66/22kV	Y					20/33	(2015)		
ES (Essendon)	66/11kV	Y	20/27	(1965)	20/27	(1965)				
FE (Footscray East)	66/22kV	Y	20/30	(2010)	20/30	(1967)				
FF (Fairfield)	22/6.6kV	Y	10/13	(1950)	10/13	(1950)	10/13	(1950)		
FT (Flemington)	66/11kV	Y	20/30	(1970)	20/30	(1970)				
FW (Footscray West)	66/22kV	Y	20/30	(1966)	20/30	(1966)	20/30	(1971)		

Zone Substation	Voltage Ratio	NER	Transformer MVA Capacity (Year of Manufacture)							
			1		2		3		4	
HB (Heidelberg)	66/11kV	Y	20/30	(1966)			20/30	(1966)		
NH (North Heidelberg)	66/22kV	Y	20/30	(1973)	20/30	(1973)	20/33	(2005)		
NS (North Essendon)	22/11kV	Y	12/18	(2017)	12/18	(2017)	12/18	(2017)		
NT (Newport)	66/22kV	Y	35/38	(1949)			35/38	(1949)		
PTN (Preston)	66/22kV	Y	20/33	(2019)	20/33	(2019)				
PV (Pascoe Vale)	66/11kV	Y	20/33	(2011)	20/33	(2012)	10/11	(1964)		
SBY (Sunbury)	66/22kV	Y	10/16	(2002)	20/33	(2018)	10/16	(2000)		
SHM (Sydenham)	66/22kV	Y*	20/33	(2008)	20/33	(2010)				
ST (Somerton)	66/22kV	Y	20/33	(1985)	20/33	(1985)	20/33	(1996)		
TH (Tottenham)	66/22kV	Y	30/45	(1984)	30/45	(1984)				
TMA (Tullamarine)	66/22kV	Y	20/33	(2015)	20/33	(2015)				
YVE (Yarraville)	66/22kV	Y	20/33	(2013)	20/33	(2013)			10/16	(2000)

* SHM Plus REFCL

Table 4-2 lists the population, and make/types for 66kV bushings and tap changers. The ABB type GSA 66kV bushings and MR tap changers are modern items of HV plant fitted to new and some existing older transformers. Whereas the English Electric (EE), ABB type GOB and SECV type of 66kV bushings are original and fitted to older transformers. This is also the case for all tap changers with the exception of the MR tap changer.

Table 4-2: Power Transformer 66kV Bushing and Tap changer Information

Zone Substation	66kV Transformer Bushing Type				Tap changer Type			
	1	2	3	4	1	2	3	4
AW (Airport West)	ABB GSA	ABB SEC	ABB GSA	ASEA	AEI	Ferranti	AEI	ABB UZF
BD (Broadmeadows)	ABB GSA	ABB GSA	ABB GSA	ABB GOB	Ferranti	Ferranti	Ferranti	ASEA
BMS (Broadmeadows South)	ABB GSA	ABB GSA			MR	MR		
BY (Braybrook)	ABB GSA	ABB GOB			AEI	ABB UZ		

Zone Substation	66kV Transformer Bushing Type				Tap changer Type			
	1	2	3	4	1	2	3	4
CN (Coburg North)	ABB GSA	ABB GSA	ABB GOB		AEI	AEI	ASEA	
COO (Coolaroo)	ABB GOB	ABB GOB			MR	MR		
CS (Coburg South)	SECV L1079	SECV L1079			Ferranti	Ferranti		
EP (East Preston)	EE	ABB GOB	MIC SECV	EE	Fuller	ABB	EE	EE
EPN (East Preston)			ABB GSA				MR	
ES (Essendon)	ABB GSA	EE			Fuller	Fuller		
FE (Footscray East)	ABB GOB	EE			MR Vac	AEI		
FF (Fairfield)	n/a	n/a	n/a			GEC/EE	GEC/EE	GEC/EE
FT (Flemington)	EE	ASEA			Ferranti	Ferranti		
FW (Footscray West)	ABB GSA	ABB GSA	SECV 68/30A		AEI	AEI	Ferranti	
HB (Heidelberg)	EE		EE		Fuller		Fuller	
NH (North Heidelberg)	SECV L1079	SECV L1079	ABB GOB		Ferranti	Ferranti	ABB	
NS (North Essendon)	n/a	n/a	n/a		MR	MR	MR	
NT (Newport)	MIC SECV		MIC SECV		EE		EE	
PTN (Preston)	ABB GSA	ABB GSA			MR	MR		
PV (Pascoe Vale)	ABB GSA	ABB GSA	MIC SECV		MR	MR	Fuller	
SBY (Sunbury)	ABB GOB	ABB GSA	ABB GOB		ABB	MR	ABB	
SHM (Sydenham)	ABB GOB	ABB GOB			ABB UZF	MR		
ST (Somerton)	MICAFIL UTXF	MICAFIL UTXF	ABB GOB		ASEA	ASEA	ABB UZF	
TH (Tottenham)	MICAFIL UTXF	MICAFIL UTXF			ASEA	ASEA		

Zone Substation	66kV Transformer Bushing Type				Tap changer Type			
	1	2	3	4	1	2	3	4
TMA (Tullamarine)	ABB GSA	ABB GSA			MR	MR		
YVE (Yarraville)	ABB GSA	ABB GSA		ABB GOB	MR	MR		ABB UZP

Table 4-3 lists NER and REFCL details. There are 5 different manufacturers of Neutral Earth Resistors (NER) installed with the Zone Substations (ZSS). The oldest NER's are installed at ZSS NT and TH.

Table 4-3: NER and REFCL Information

Zone Substation	Voltage Ratio	NER	Manufacturer	Installation year
AW (Airport West)	66/22kV	Y	FORTRESS SYSTEMS	2010
BD (Broadmeadows)	66/22kV	Y	FORTRESS SYSTEMS	2010
BMS (Broadmeadows South)	66/22kV	Y	FORTRESS SYSTEMS	2014
BY (Braybrook)	66/22kV	Y	FORTRESS SYSTEMS	1999
CN (Coburg North)	66/22kV	Y	FORTRESS SYSTEMS	2010
COO (Coolaroo)	66/22kV	Y	MS RESISTANCES	2006
CS (Coburg South)	66/22kV	Y	FORTRESS SYSTEMS	2004
EP (East Preston)	66/6.6kV	N	–	–
EPN (East Preston)	66/22kV	Y	FORTRESS SYSTEMS	2015
ES (Essendon)	66/11kV	Y	FORTRESS SYSTEMS	2008
FE (Footscray East)	66/22kV	Y	FORTRESS SYSTEMS	2010
FF (Fairfield)	22/6.6kV	Y	FORTRESS SYSTEMS	2010
FT (Flemington)	66/11kV	Y	FORTRESS SYSTEMS	2008
FW (Footscray West)	66/22kV	Y	OHMIC CONTROLS	2003
HB (Heidelberg)	66/11kV	Y	FORTRESS SYSTEMS	2011
NH (North Heidelberg)	66/22kV	Y	FORTRESS SYSTEMS	2005
NS (North Essendon)	22/11kV	Y	FORTRESS SYSTEMS	2008
NT (Newport)	66/22kV	Y	FORTRESS SYSTEMS	1997
PTN (Preston)	66/22kV	Y	TBA	2019
PV (Pascoe Vale)	66/11kV	Y	FORTRESS SYSTEMS	2006
SBY (Sunbury)	66/22kV	Y	FORTRESS SYSTEMS	1999

Zone Substation	Voltage Ratio	NER	Manufacturer	Installation year
SHM (Sydenham)	66/22kV	Y*	FORTRESS SYSTEMS	2007
SHM (Sydenham)	66/22kV	REFCL	EGE	2016
ST (Somerton)	66/22kV	Y	FORTRESS SYSTEMS	2010
TH (Tottenham)	66/22kV	Y	FORTRESS SYSTEMS	1997
TMA (Tullamarine)	66/22kV	Y	FORTRESS SYSTEMS	2015
YVE (Yarraville)	66/22kV	Y	FORTRESS SYSTEMS	2013

The JEN operates 26 zone substations and 4 HV customer substations with Jemena assets installed[3]. These substations are equipped with:

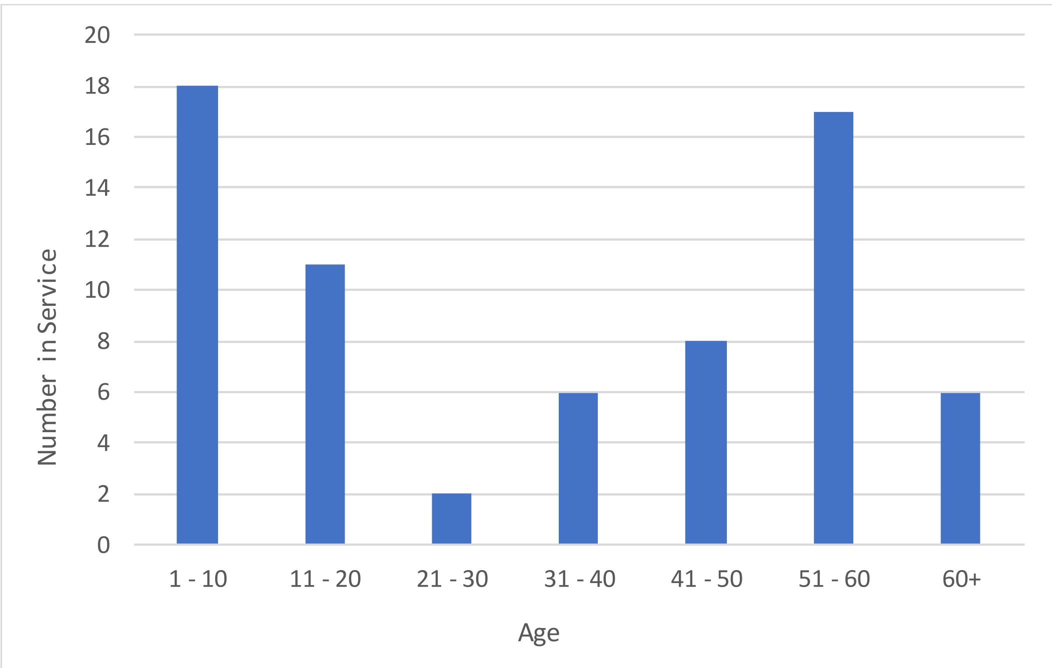
- 65 power transformers ranging in age from 1 to 69 years of two main types; 66kV primary voltage and secondary voltages of 22kV, 11kV or 6.6kV, and 22kV primary voltage and secondary voltages of 11kV or 6.6kV.

4.1.3 AGE PROFILE

All transformers deteriorate with in-service time and thus it can be expected that the oldest units are likely to be in the poorest condition. There are many other factors that will contribute to the combination of data that is used to determine condition.

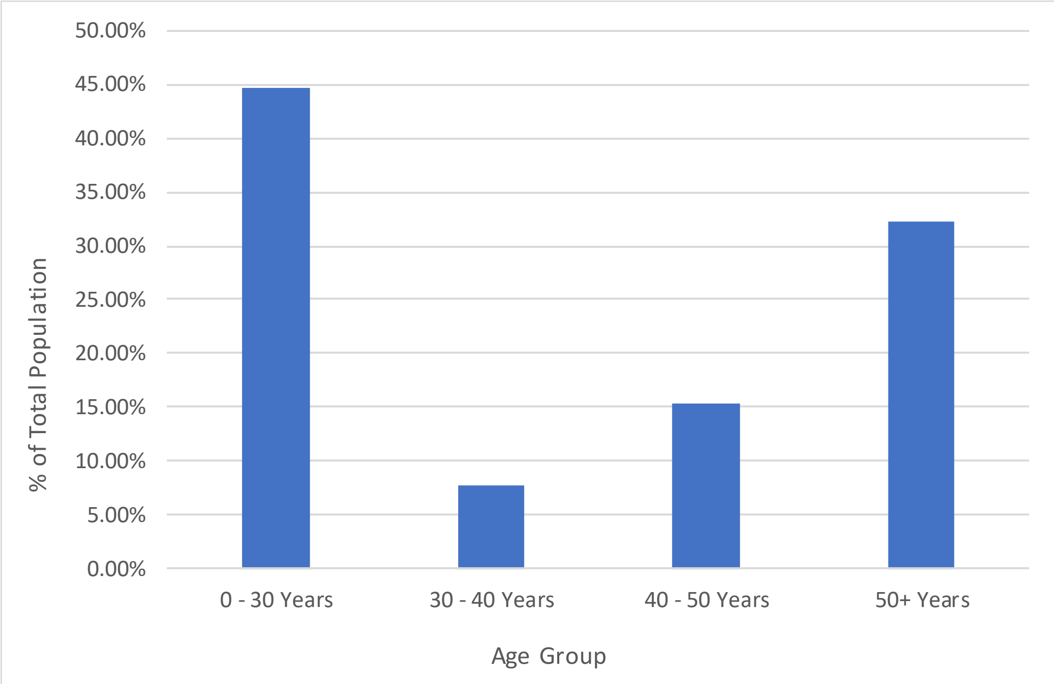
Figure 4–1 shows the power transformer age profile and Figure 4–3 shows the percentage of population in nominated age groups.

Figure 4–1: Power Transformers Age Profile



[3] Refer to Appendix K for a list of JEN zone substations and HV customer substations with Jemena assets installed.

Figure 4–2: Power Transformers Age vs Population



Of the various transformer age groups:

- Twenty one are over 50 years old, representing 31% of the total population (which will be prioritised for replacement using a condition and risk-based approach); and
- Ten are between 40 and 50 years old, representing 15% of the total population (the ageing condition of which will be closely monitored as they approach and exceed 50 years).

4.1.4 RISK

This section includes information about transformer risk profiles involving the way that asset sub-class criticality is established, the risks posed by transformer 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 affected zone substations.

This information specifically involves:

- Asset class criticality score (sub asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Condition Based Risk Management (CBRM) for identifying assets approaching end of life;
- Existing controls ;
- Asset Spares;
- Contingency;
- Future risks (involving other potential risk issues currently being managed).

Summary of risk aspects for transformers:

Criticality – being an asset of low volume; typically two or three per substation, high cost ($1.8M) and long replacement lead time (8 months) plus potential for a failure to leave up to 10,000 customer without supply, classifies this asset to be critical. It is acknowledged that there are only a few substations that are loaded beyond cyclic loading, with insufficient transfer capability and thus customers will be without supply for a transformer failure.

Failure modes – winding and bushing insulation breakdown leading to total transformer failure are the most serious types of failures. There are multiple causes which are detailed in the following sections.

Risks are captured in the Risk Register files located in the JCARS[4] system. If a major failure of a transformer occurs; the following summary of risks have been identified:

- Health, Safety & Environmental risk (tank rupture, oil leakage, flying fragments, possible fire) – Moderate;

  An increased fire consequence at specific ZSS due to lack of blast walls; CN,EP, FF and SBY also due to close proximity to residential houses at FF.

- Regulatory & Compliance risk (Non-compliance on safety, penalties) – Moderate;
- Financial risk (significant unplanned cost of replacement) – Moderate;
- Operational risk (loss of transformation capacity; possible loss of supply if during peak load period risk) – Moderate;

  An increased supply loss consequence at ZSS loaded above cyclic rating and with insufficient transfer capability at CS, EPN, FT, HB, SBY and SHM.

- Brand/Reputation/Stakeholders risk (possible large customer numbers off supply) – Moderate. Aa above for CS, EPN, FT, HB, SBY and SHM

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.1.4.2., together with initiation of replacement projects for assets determined to be at risk of major failure. Replacement prior to failure is the optimum control measure as spare transformers are not available and post failure controls is not a justifiable option. Some 66kV bushing and tap changer spares are held. A transformer contingency plan has been prepared which details the risk mitigation measures should a transformer failure occur. Refer to doc No. ELE AM PL 0010.

The condition of all in-service transformers will degrade over time due to insulation deterioration - caused by heat, insulating medium contamination - due to moisture and acidity, plus environmental exposure. Therefore transformer failure risk will increase in the future unless end-of-life condition units are replaced.

Collection and analysis, as well as monitoring trends over time, will continue to provide more accurate condition assessment; as well as trialling of on-line condition monitoring to provide real time data.

Emerging risks for power transformers include:

- Greater likelihood of winding/mechanical failure because of a through-fault on the HV distribution system due to degraded paper on end of life transformers;
- Specific types of power transformer 66kV bushings have failed on other electricity networks throughout Australia. Cyclic testing of 66kV bushings is performed to identify bushings that have some degree of moisture ingress which can lead to bushing failure. Bushings with deteriorated insulation condition are replaced.

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[4] For more information on JCARs please click here.

- Increasing likelihood of transformer and tap changer plant failures will increase risks of outages. A review of transformer and tap changer stocks may be justified as a measure to mitigate these risks.
- Transformers with corrosive sulphur in oil which can lead to rapid insulation system deterioration.

4.1.4.1 Criticality

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub asset class level by following the Asset Criticality Assessment Procedure (JEM AM PR 0016). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of Jemena'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.

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures.

Major failure of transformers which cannot be repaired within 24 hours, are only strictly considered as Strategic, if the substation loading is greater than transformer cyclic ratings and insufficient transfer capacity exists. However due to the increased risk to the surrounding network, the costs and time required to replace a failed transformer, it is critical that contingency plans are in place for such events. Refer to Doc No. ELE AM PL 0010 – Zone Substation Transformer Contingency Plan.

As detailed in 4.1.4.1 transformer failures at heavily loaded substations CS, EPN, FT, HB, SBY and SHM are considered strategic due to likely loss of supply to customers.

Zone substation transformers are critical, low volume assets. From an overall service perspective, two or three transformers typically form a zone substation and supply in excess of 10,000 customers.

The transformer has an asset criticality score of AC4 (High) due to operational and health and safety consequences associated with failures.

A transformer's criticality (importance) is defined by:

- High replacement cost - Approximately $1.8 million per unit;
- Strategic impact on customer supply – (If the N-1 rating is exceeded and transfer capability is limited, then load shedding will be required if a transformer failure occurs);
- Long lead time for repair or replacement - Procurement on a new transformer is typically eight months;
- High consequence of failure – Potential loss of supply, with the legal, reputational, regulatory impacts and occupational health, safety and environmental issues; and
- Due to the location within the network, most transformers are classified as highly critical as the zone substation is supplying critical customers. In addition, customers on life support require electricity at all times. These customer are listed by feeder. At zone substation level, currently only one ZSS; EPN does not have life support customers. Therefore all substations are critical from a life support requirement perspective.

Below is a list of critical customers and total customer numbers supplied by each zone substation.

Table 4-4: JEN Major Customers

Substation	Major customers	Total customers
AW	Gladstone Park Shopping Centre Westfield - Airport West	22,682
BD	Bolinda Co-Gen Hume - Nestle Corporation	13,235
BMS	Camp Serum Labs (CSL) VR Glenroy No.1 & No.2 Supply	3,455
BY	Highpoint Shopping Centre	9,971
CN	Hocking - VISY Melbourne Water	23,953
COO	VR Roxburgh Park Traction VR Coolaroo Traction Roxburgh Park Shopping Centre	15,840
CS	John Fawkner Hospital MMTB Preston	23,395
EP	BOC Gas Chifley - BTR Kennon	5,048
EPN	Northland Shopping Centre Northland Homemaker Centre	4,541
ES	MTA Matthews Ave Traction Essendon Private Hospital MMTB - Essendon	15,989
FE	VR Footscray Tramways Western General Hospital	13,935
FF	Residential and commercial	6,325
FT	MTB - Ascot Vale Melbourne Showgrounds LV Supply to VR Signals Flemington Racecourse	14,117
FW	Western General Hospital Coolstore VR Tottenham	14,262
HB	11kV Island - Residential and commercial	8,856

Substation	Major customers	Total customers
NH	Bioscience Austin Hospital Northland Shopping Centre	19,427
NS	Moonee Valley racecourse Australian Taxation Office	11,125
NT	Metro Train No.1 Supply Tenix - Dockyard No.11 & No.2 Supply Glassworks Standby Feeder Williamstown Hospital	12,551
P	Shutdown - No longer in service	
PV	Residential, commercial and industrial supply area	19,395
SBY	Metro Trains	15,751
SHM	Metro Trains	14,117
ST	VR - Craigieburn Maintenance Yard Reserve Bank Venture Automotive Systems Tubemakers Craigieburn Shopping Centre	16,301
TH	Sims Metal, OLEX cables, National Forge	1,293
TMA	ANZ Bank, Next DC	1,533
TT	La Trobe Uni Co-Gen MMTB	14,171
WT	Simpson Army Barracks - WT4	145
YVE	ACI Metro Trains Westgate Bridge CSR Gyprock	5,934

It can be seen that the vast majority of substations supply major customers and together with life support requirements, all zone substations are deemed critical.

The consequence of transformer failure is predominantly dependent on the capacity of the zone substation to supply customers after load transfer. Based on the present planning, utilising 10% PoE 2018 summer loads; the following zone substations have insufficient transfer capacity should a transformer fail and therefore load shedding will occur:

- At CS the station N-1 rating is 42.2MVA, the 10% PoE MD in 2018 is 59.7MVA and the load transfer available to adjacent ZSS is 13.4MVA. There is a shortfall of 4.1MVA. Rotating load shedding will be necessary. This situation will improve after load transfers to new PTN zone sub (scheduled to be built in 2019) become available post 2019.
- At EPN the station N-1 rating is 0.0MVA (EPN is a single transformer station, and in the event of a failure of the transformer all customers will be off supply initially, until load transfers take place). The 10% PoE MD in 2018 is 24.2MVA and the load transfer available to adjacent ZSS is 11.3MVA. There is a shortfall of 12.9MVA. Rotating load shedding may be necessary. Installation of the second transformer around 2021/22 will resolve this situation.
- At FT the station N-1 rating is 23.9MVA, the 10% PoE MD in 2018 is 41.3MVA and the load transfer available to adjacent ZSS is 2.3MVA. There is a shortfall of 15.1MVA. Rotating load shedding will be necessary. Upgrade of transformer cables and switchboards is taking place in 2018 which will increase cyclic rating to 38.4 MVA (N-1), which will still not be sufficient for the next 5 years.
- At HB the station N-1 rating is 29.2MVA, the 10% PoE MD in 2018 is 29.6MVA and the load transfer available to adjacent ZSS is 0.0MVA as HB is an island. There is a shortfall of 0.4MVA. Rotating load shedding may be necessary.
- At SHM the station N-1 rating is 38MVA, the 10% PoE MD 2018 is 45.6MVA and the load transfer available to adjacent ZSS is 4.8MVA. There is a shortfall of 2.8MVA. Rotating load shedding will be necessary. This situation will improve after load transfers to new PLN zone sub (scheduled to be built in 2025) become available post 2025.

For 66kV bushings, criticality (importance) is defined by:

- replacement cost – approximately $193k per transformer;
- high strategic impact on customer supply – where demand exceeds N-1 capacity and transfer capability is limited, load shedding will be required in the event of a failure;
- long lead time for replacement (typically 4 months); and
- high safety and environmental consequence of failure (porcelain/metal projectiles, fire, oil spill).

Criticality is further assessed for individual circuit breakers utilising a condition based risk model (CBRM). Condition Based Risk Management (CBRM), which was introduced for JEN circuit breakers in 2014, is utilised to predict condition into the future (Health Indices) and estimate Probability of Failure. These tools are utilised to indicate required changes to asset management plans, to develop asset investment plans using existing asset data and other information and determine when end-of-life replacement will be required. Assets with a higher health index score are targeted for further analysis before imminent replacement. For further information on CBRM, it's inputs and outputs and methodology please refer to Appendix L.

Increasing proportion of transformer population in future projected to have deteriorated oil and paper insulation in poor condition (CBRM health index >7: now 8 units, in 10 years 26 units). Likely to need increased condition monitoring including on-line DGA & DLA.

4.1.4.2 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 Critical Spares Assessment Procedure (JEM AM PR 0015). It was determined that adequate transformer component spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team.

Due to the increased risk to the surrounding network, the costs and time required to replace a failed transformer, a contingency plan has been prepared to evaluate options for restoration to system normal conditions.

As documented in the Transformer Contingency Plan Doc. No. ELE AM PL 0010, it is possible, should a long term emergency situation exist, that a lightly loaded transformer could be relocated from one substation to another.

The Customer & System Planning team reviews loading and transformer ratings annually to minimise the possibility of zone substation exceeding their N-1 ratings. Augmentation projects are initiated where justifiable. System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub transmission line.

Primary plant assets are typically high cost assets and holding of additional spares is not currently justified economically. Critical Spares Assessment Procedure (JEM AM PR 0015) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I. When assets are retired from service consideration is given to retaining components or entire asset as spares to service existing aging fleet.

Two spare 66/6.6kV and 66/11kV transformers are held as shown in the table below. Both of the above transformers are not in a good condition, therefore their use as a spare is unsuitable and a review of required spares will be undertaken.

Table 4-5: Spare JEN Power Transformers

ZSS	Manufacturer	Age	Voltage Ratio (kV)	Rating (MVA)	Radiators	Condition
HB	ENGLISH ELECTRIC	58	66/6.6	20/27	Detached	Poor Paper
YVE	WILSON	56	66/11	20/27	Attached	Poor

In 2015 a dedicated bushing hot room was constructed and commissioned at Tullamarine depot. All bushings were Tan Delta tested prior to being positioned within the hot room; if bushings failed electrical and/or visual tests they were disposed of accordingly. The hot room has 8 English Electric 66kV bushings and 4 (+4 on order) ABB GSA 66kV bushings.

Wall bushings for Zone Substation ST are still stored onsite. Bushings typically have a delivery lead time of 4 months therefore a fleet of spares as per above is vital to maintain network capacity in the event of a failure.

Bushing storage: It is important to cover the bushing stem with an oil filled tube for storage. This needs to be implemented to avoid moisture ingress. A hot room has been installed and is now operational at the Tullamarine Depot for the optimal storage of bushings

4.1.4.3 Failure Modes

Transformers are generally reliable and the risk of failure is considered to be low, however as the condition of a transformer deteriorates, the risk of failure increases. The major risk associated with transformer operation has been identified as personnel safety and loss of transformation capacity in the event of potential failures.

Typical transformer failure modes include:

- Winding/mechanical failure, usually due to a through-fault on the HV distribution system;

- Insulation failure due to lightning, over-voltages due to switching, water penetration; overloading (excessive temperatures), oil and aged paper degradation;
- Thermal failure due to a deteriorated or high resistance joint or connection, overloading, cooling system failure;
- External flashover between bushings or to any earthed structures, due to pollution, surface degradation, birds or animals; and
- Moisture ingress leading to bushing insulation failure

Based on the known past history of transformer serious failures being; 1in 15 years in the JEN and 3 in 40 years in the rest of Victoria, the Probability of Failure is estimated as Unlikely (could occur sometime in next 10 years).

The consequences resulting from these failure modes can include:

- Main tank or bushing rupture possibly causing extensive oil contamination and/or fire;
- Associated explosion causing shattered airborne debris such as metal and porcelain;
- Loss of transformation capacity, with reduced availability to take outages on other in-service assets and with possible loss of supply to customer if ZSS is loaded above cyclic ratings; and
- Additional loading on remaining in-service transformers creating increased risk of cascade failure of second unit and accelerated aging.

A tabulation (spreadsheet) of transformer and 66kV bushing Condition Indices is available in Appendix E.

4.1.4.4 *CBRM Health and Risk Analysis*

The graphs below show the CBRM Health Indices for JEN's population of transformers at the present time as well as in 5 years and 10 years if no replacements are made.

Figure 4–3: Transformer Health Indices at Year 0

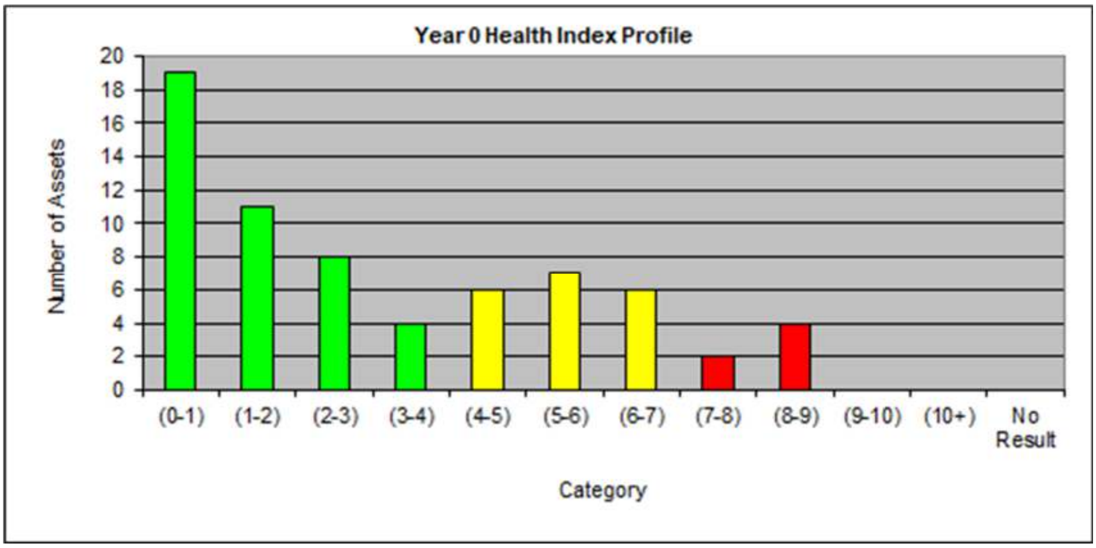


Figure 4–3 shows there are 7 transformer in the red zone with Health Indices of 7 or above, indicating a high probability of failure. These transformer are: FF 1, 2 & 3; ES 1 & 2; and HB 1.

Total risk for all failure scenarios at Year 0 is calculated to be $1.70M.

Figure 4–4: Transformer Health Indices at year 5

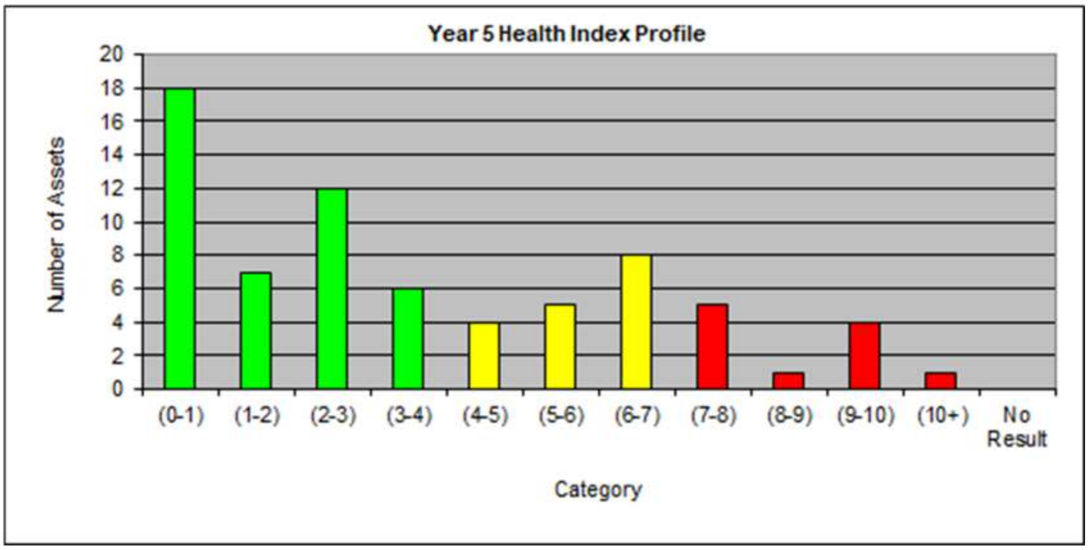


Figure 4–4 shows there will be 11 transformer in the red zone, (HI>7) in 5 years if no replacements are made. The one unit (FF No.1 Transformer) in the 10+ category would be in danger of immediate failure if still in service. These transformers are: FF 1, 2 & 3; ES 1 & 2; HB 1; EP-A 3; NT 1 & 3; and BD 2 & 3.

Total risk for all failure scenarios at Year 5 is calculated to be $2.03M.

Figure 4–5: Transformer Health Indices at year 10

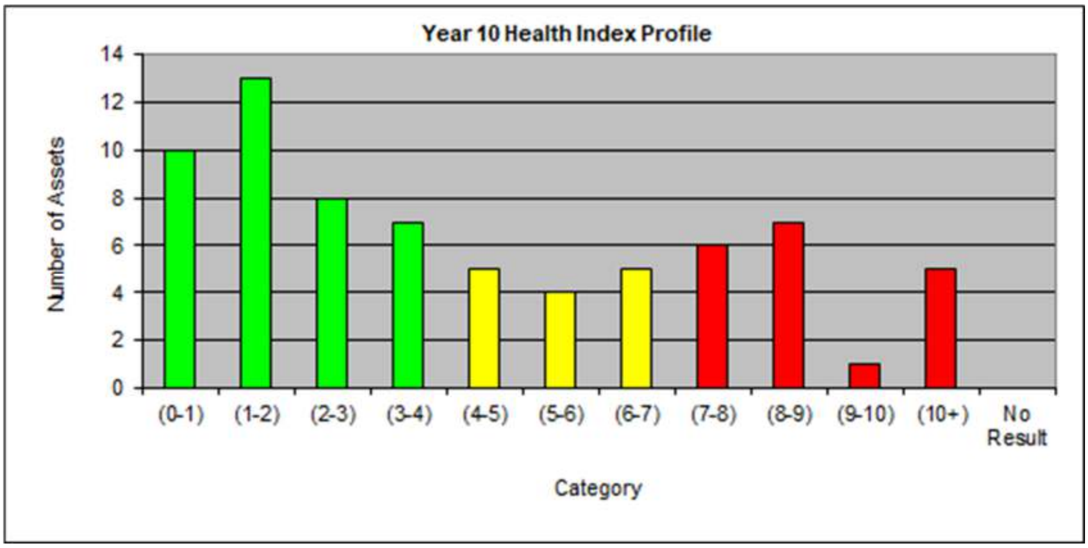


Figure 4–5 shows there will be 19 transformers in the red zone (HI>7) in 10 years if no replacements are made. The five units (FF 1, 2 & 3 and ES 1 & 2) in the 10+ category would be in danger of immediate failure if still in service. These transformer are: AW 3; BD 1, 2 & 3; BY 1; CN 1 & 2; EPA 1 & 3; EPB 4; ES 1 & 2; FF 1, 2 & 3; HB 1; NT 1 & 3.

Total risk for all failure scenarios at Year 10 is calculated to be $2.56M.

Figure 4–6: Transformer Health Indices at year 15

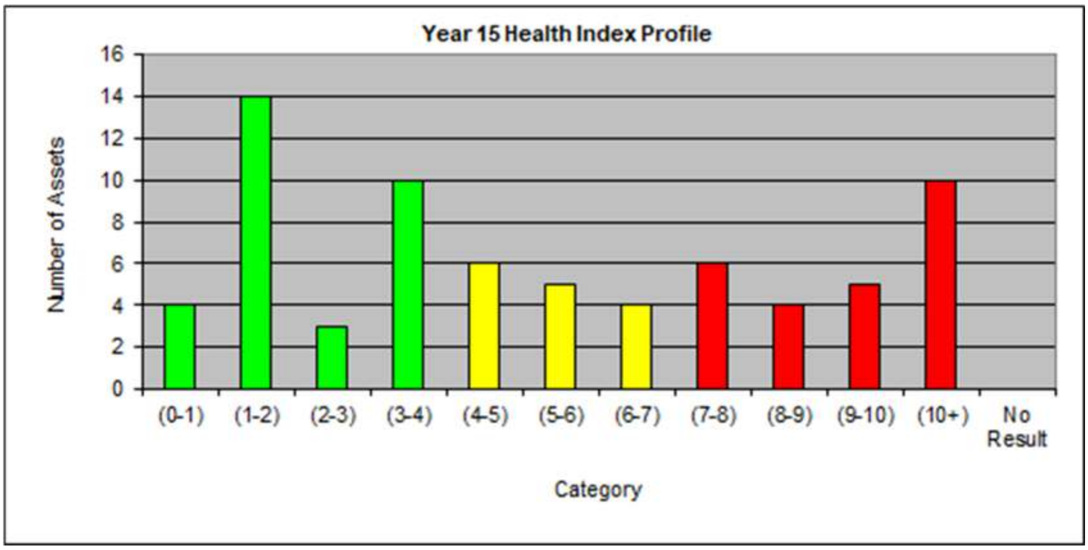


Figure 4–6 shows there will be 25 transformer in the red zone, (HI>7) in 15 years if no replacements are made.

Figure 4–7: Transformer Health Indices at year 20

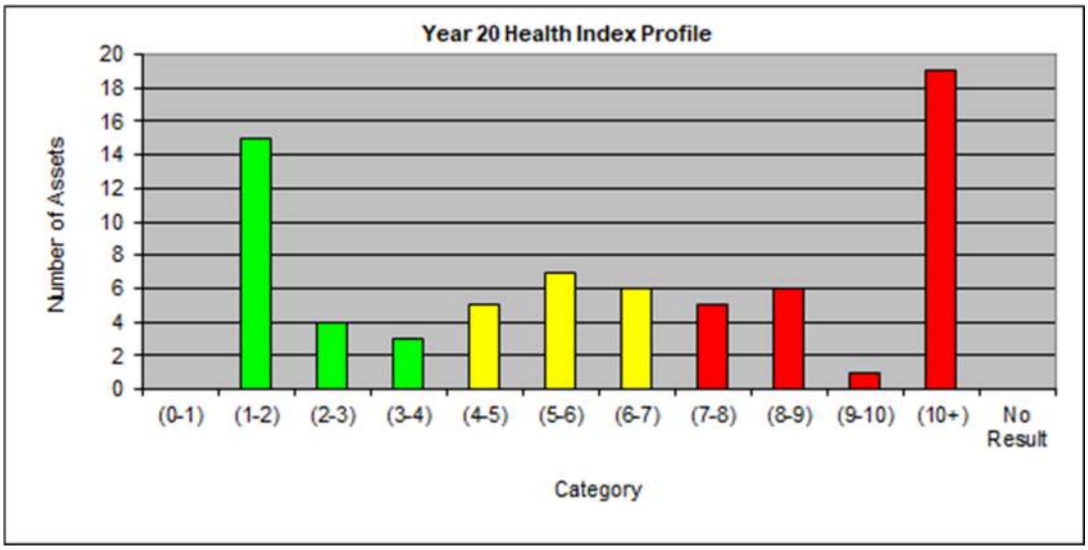
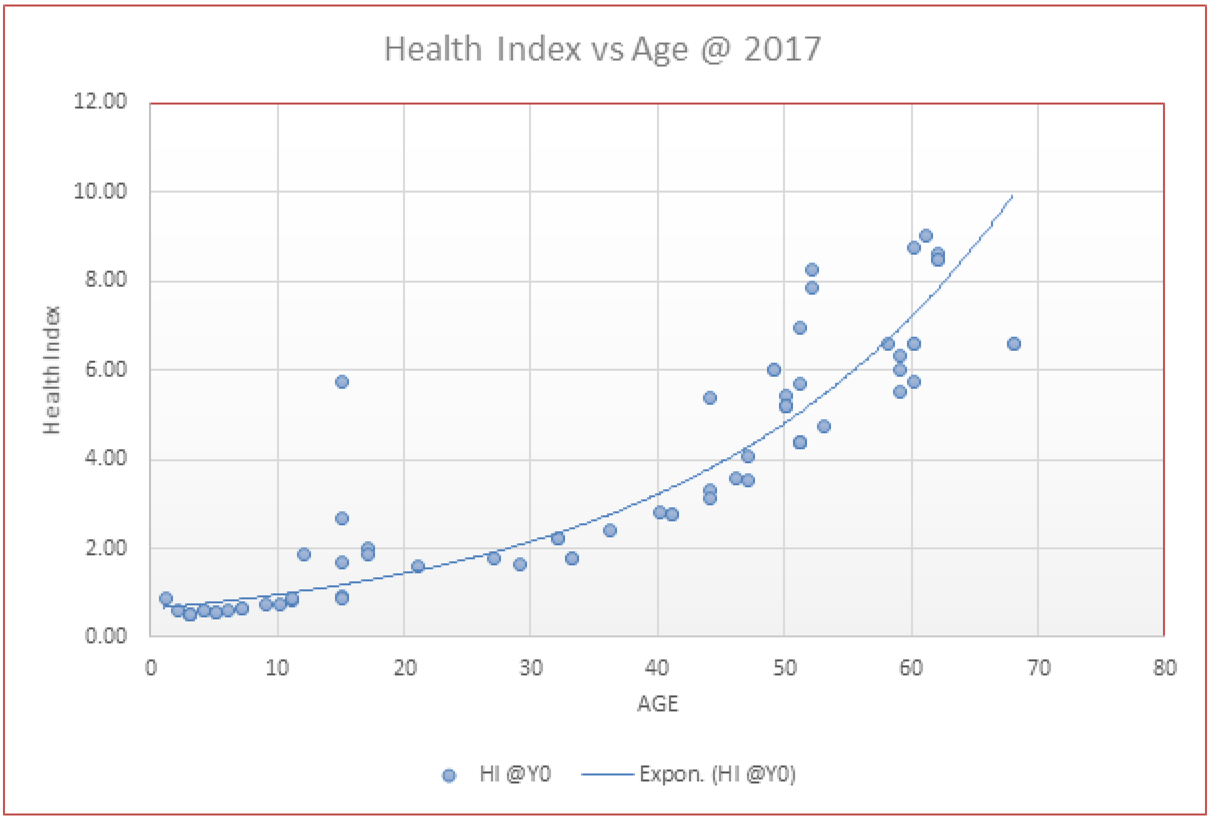


Figure 4–7 shows there will be 31 transformer in the red zone, (HI>7) in 20 years if no replacements are made.

Multiple condition monitoring checks and tests are conducted to derive an overall condition assessment for each transformer. It is expected that the transformers in the poorest condition will also be among the oldest units. Figure 4–8 below illustrates the relationship between the CBRM Health Index and transformer age. There is a reasonable correlation between transformer age and high HI.

Figure 4–8: Correlation between Transformer Age and Health Index



4.1.4.5 Existing Controls

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.1.4.2., together with initiation of replacement projects for assets determined to be in danger of major failure.

A summary of controls in place include the following:

- Control room monitoring of loading, alarms for gas production, cooling system failure, tap changer anomalies, protection trips;
- Monthly inspections by operators, annual engineering audits;
- Scheduled maintenance on tap changers and transformer/ auxiliaries;
- Maintenance training and documented maintenance instructions;
- Scheduled condition monitoring tests of 66kV bushings, oil (DGA) & PDC/RVM winding electrical tests. Replacements are planned as required;
- Refurbishment of gaskets, tap changers (Ferranti) and cooling auxiliaries;
- Oil regeneration and dry-outs;
- Corrective repairs of any defects;
- Loading assessments;
- Condition based replacements; and
- Assessment of spares potential from retired units

4.1.4.6 Further Information on CBRM

For further information on CBRM please refer to ELE GU 0005 Condition Based Risk Management (CBRM) Application Guide. The guide provides a summary of how Jemena utilises CBRM to justify future replacement volumes for distribution and zone substation assets. It outlies the different inputs required and their associated outputs and how these outputs are interpreted.

4.1.5 PERFORMANCE FACTORS

Transformers are expected to provide their rated transformation function continuously for a life time of at least 50 years. Therefore all factors contributing to maintaining satisfactory **condition** are essential to achieve this goal.

Specific power transformer performance measures (and condition monitoring) include the following:

- Oil condition: conductivity, quality, moisture in oil, acidity in oil, dissolved gas analysis, dielectric, interfacial tension, and copper sulphide presence;
- Bushing condition; and
- Paper condition: PDC/RVM, paper moisture, furan, and paper DP

These performance measures are recorded in the Transformer Condition Index in Appendix E.

Other performance measures include assessments involving:

- On-load tap-changers;
- Winding temperature indicators;
- Noise reduction;
- Oil containment; and
- Neutral earthing resistors

Transformers are expected to operate continuously providing its transformation capacity up to its rated values to meet the needs of customer demand and network operating variations, with acceptable risks relating to safety, environmental impact and financial costs.

The table below documents items that constitute performance requirements.

Table 4-6: Asset Performance Drivers

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment, Regulatory compliance	66kV bushing on ZS Transformers (known manufacturer defect in Victorian electricity networks)	Failure of bushing leading to customer supply issue and potential to damage a transformer beyond repair.
Asset Integrity	Long lead time for repair/replacement of zone substation transformers	Risk to customer supply (approx. 10,000 customers impacted)
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Irreversible aging of zone substation transformers due to moisture content in the insulation	Increasing likelihood of failure of the asset leading to customers off supply, and increased risk to public, employee and contractor safety.

Driver	Risk/Opportunity Description	Consequence
Asset Integrity	Overloading of zone substation transformers	Reduce asset life of transformers causing earlier replacement
Regulatory compliance, Health, Safety and Environment	Reducing core clamping pressure in Zone substation transformer	Increasing levels of noise and reduced ability to withstand a through fault
Regulatory compliance, Health, Safety and Environment	Non-compliance of older stations with noise regulations (particularly during peak load conditions)	Increasing levels of noise
Regulatory compliance, Health, Safety and Environment	Typical ZS transformers contain 18,000 litres of oil and historically not all of these transformers have been bunded.	In the event of oil leaks, risk of non-compliance with environmental requirements.
Technological Developments	Improved preventive moisture in insulation methodologies extending the life of the insulation	Improved asset maintenance (Trojan equipment)

4.1.5.1 *Performance requirements and targets*

Failure Prevention – avoiding catastrophic (unplanned outage more than 24 hours) power transformer failures from occurring within zone substations - target **zero** pa.

Factors affecting asset life:

The design life of transformers in accordance with Australian and international standards, when constantly loaded to nameplate ratings is 30 years. When utilised within an electrical distribution network, loading varies and for the majority of time is less than nameplate ratings. Therefore, life can be expected to be greater than 30 years. Properly electrically protected, correctly loaded (within the various cyclic ratings) and adequately maintained, a transformer's life expectancy can exceed 50 years.

Jemena has transformers in-service which are in excess of 50 years old; however in the past, Jemena have had transformers fail earlier than 50 years. There is a low probability of failure of new to midlife transformers. As an example, the former No.1 transformer at zone substation EP was installed in 1960 and failed in service in 2002 (42 years of life).

An oil-filled transformer's life expectancy depends on the life of its insulation system, which is defined by a chemical process that primarily depends on temperature and time.

Other factors, such as the presence of oxygen and moisture, will accelerate the aging process.

A transformer's performance is monitored to determine if the aging process is accelerating, as early corrective actions, such as oil conditioning, can control the various factors leading to insulation degradation. The mechanical condition of the transformers paper insulation will usually determine when a transformer is at end of life as this degradation is not reversible and when the condition has reached a poor state (a DP of approximately 250), there is no economic corrective action to maintain the performance of the transformer. It is at this time that major refurbishment (if practicable and economic) or replacement of the transformer will be required.

The CBRM tool calculates a transformer's expected life taking into account a whole range of condition factors.

Replacement plans

Although some transformers have continued to operate satisfactorily for over 50 years, a 50-year-old transformer is approaching the end of its practical life. Replacement plans are based on condition and reliability and not age alone.

Replacement plans should consider a variety of factors, such as capacity constraints and the condition of other equipment within the zone substation.

66kV Transformer Bushing Life Expectancy

The 66kV transformer bushing life expectancy has a general life expectancy in line with the age of the transformer. However, there have been specific bushing types with incipient failure mechanisms built in during the manufacturing process which have been identified as problematic (i.e. English Electric and SECV). These bushings have had replacement programs initiated.

Factors affecting life expectancy include:

Bushings (SRBP, RIP and OIP) are designed to withstand the electrical field strength produced in the insulation when any earthed material is present. As the strength of the electrical field increases, leakage paths may develop within the insulation. If the energy of the leakage path overcomes the dielectric strength of the insulation, it may puncture the insulation and allow the electrical energy to conduct to the nearest earthed material causing burning and arcing. Therefore the insulation is what determines life expectancy and is electrically tested via Tan Delta.

4.1.5.2 Transformer Assessments

A number of factors are assessed to determine if individual transformers have a high probability that the unit will continue to reliably perform its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and analysis of actual performance are examined. The following reports provide data for these areas:

The results of condition monitoring and electrical tests are tabulated in spreadsheets. These together with many other factors are utilised in the CBRM model to provide a Health Index and risk value for individual and the population of transformers. Refer to Condition Assessment Section further below for CBRM output graphs.

Condition issues identified at Zone Substations are summarised as follows:

Airport West (AW)

- The No.1 transformer started to produce gas (1ppm acetylene) and a high resistance connection was identified inside the selector switch compartment and repaired. Testing identified a high resistance connection internal to the main tank. During the bushing replacement and oil leak repairs, a loose connection was identified on a tapping lead and was repaired accordingly.
- No.1 & No.3 transformers neutral bushings have high DLA readings and are planned for replacement in 2020.

Broadmeadows (BD)

- The No.2 transformer had elevated oil moisture content that has been processed with a Trojan dry-out system and dried to acceptable limits. Results from tests conducted in 2013 indicate the oil's water content is now good. Monitoring has been ongoing since 2013.
- A project was completed in 2013/14 to replace the No.1, No.2, and No.3 transformers' lid gaskets and 66kV bushings. Paper samples were taken from the HV bushings winding leads inside the transformers. The DP values of the No.1, No.2 and No.3 transformers are 292, 253 and 594 respectively. The No.2 transformer is programmed for replacement in the 2021 – 2025

price reset period and the No.1 transformer will be taken off load and operated as a hot standby.

Coburg North (CN)

- No.1 transformer moisture level in oil is currently fair. This will be monitored and prioritised from a Trojan dry-out. 2016 results indicate both No.1 & No.2 transformers have high moisture & acid levels.
- Monitoring of the No.2 transformer diverter switch oil leaks is continuing. Remedial work will be undertaken as required. It is anticipated that gasket replacement will be necessary.

Essendon (ES)

- Relatively recent PDC testing (conducted in May 2009) on the No.1 and No.2 transformers indicate the winding insulation's paper insulation condition is average. The test results and modelling estimate the paper insulation ageing condition to equal a DP value in the range of 250±25. This indicated that the transformer insulation had reached their end of life.
- Transformer No.1 paper moisture is 3.7% (poor) and oil moisture content is 20ppm (fair).
- Transformer No.2 paper moisture is 3.6% (poor) and oil moisture content is 23ppm (fair).
- These transformers are planned to be replaced in 2019.

Fairfield (FF)

- Paper samples taken from a winding lead on No.1, 2 & 3 transformers in 2013 and 2014 had a resultant DP of 220, 230 & 250 respectively. This indicated that the insulation in all three transformers had reached their end of life.
- Acid levels, moisture and interfacial tension in No.1 transformer oil are fair and will be monitored and prioritised for oil re-generation if required.
- All the transformers are in excess of 58 years old and a Business Case has been prepared for replacement of No.1 & 2 in 2017/18. No.3 will be retained as a hot spare.
- Existing transformers have a confirmed noise issue (with a significant margin up to 22dB(A)). Sound enclosures will be constructed as part of installation of new transformers. The transformers are scheduled for replacement in 2019.

Footscray West (FW)

- Acid levels and interfacial tension in No.3 transformer oil are fair and will be monitored and prioritised for oil re-generation. Test results in 2017 still indicated fair but acceptable condition.
- The No.3 transformer enclosure roof is currently being monitored for concrete cancer. There is a project planned for 2020/21 for its replacement.

Heidelberg (HB)

- A paper sample taken from No.1 transformer in 2013 had a resultant DP of 260 (close to end of life) and a paper moisture content of 4.9% (poor). This indicates that the insulation in No.1 transformer is approaching end of life.
- Since the No.1 Transformer has a high moisture content (4.9% in paper), transformer overloads are not recommended. The International Council on Large Electrical Systems (CIGRE) working group report (A2.34 Guide for Transformer Maintenance, page 84) indicates that for moisture content in paper of 5%, the transformer should not operate within a temperature range above 100°C to 110°C to avoid a risk of bubble formation.
- No.1 and No.2 transformers are planned to be replaced in 2020/21.

Newport (NT)

- Both transformers (construction year- 1949) were previously operating at a terminal station before being recommissioned at Zone Substation NT. A similar transformer type in a neighbouring distribution business has experienced problems with the core earth.
- The main issue identified is the presence of an internal thermal fault (>400°C) which appears to have been present in both transformers since the year 2000. This is being managed by taking regular oil samples for Dissolved Gas Analysis (DGA).
- A paper sample from the No.1 transformer indicated a DP of 520. Transformer tests and paper samples are required for the No.3 transformer.

Preston (P)

- This substation was shut down in Nov 2017 and is planned to be rebuilt as a new PTN 66/22 kV substation by 2020.

Pascoe Vale (PV)

- An oil test analysis diagnosed the No.3 transformer as having an internal thermal fault <300°C, which is currently stable. During 2011, in preparation for the No.1 transformer's replacement, the No.3 transformer was tested and the high resistance internal connections were subsequently repaired. DGA monitoring is ongoing.

Sunbury (SBY)

- The No.2 transformer has been replaced with a new 66/22kV 20/33MVA unit.

Yarraville (YVE)

- The No.4 transformer (construction year- 2000) has been experiencing elevated gas volumes with rising Methane and Ethane gas levels. This indicates the oil is getting hot somewhere in the transformer. The transformer is subject to an annual DGA, and the results have consistently identified the same gas signature. An internal inspection of the transformer was undertaken in 2011 that revealed an open circuit tertiary delta winding. DGA monitoring will continue to establish a trend.

Tap Changers

All Ferranti tap changers need a half-life refurbishment involving replacement of worn components together with on-going maintenance training and documentation of maintenance procedures.

Oil level indicators on both main transformer tanks and tap changers often exhibit oil leaks and poor visibility which require rectification and or replacement. Some of the older type of conservator oil level dial indicators occasionally seize and falsely indicate the oil level. Transformer have tripped for low oil levels. Maintenance tasks have been implemented to mitigate this risk.

Transformer 66kV Bushings

All English Electric 66kV bushings are considered to have high risk of failure due to moisture ingress and insulation degradation; these are being progressively replaced (refer to the table below).

Table 4-7: English Electric 66kV Bushing Replacement Schedule

Station	Plant	Make	Model	Type	Comments
EP	No.1 Transformer	EE	A5####	RBP	Station planned to be re-built in 2021
EP	No.4 Transformer	EE		RBP	Station planned to be re-built in 2021
ES	No.2 Transformer	EE	BS 223	RBP	Transformer being replaced in 2019

Station	Plant	Make	Model	Type	Comments
FE	No.2 Transformer	EE	BS 223	RBP	Will be replaced with switchgear project 2020
FT	No.1 Transformer	EE	BS 223	RBP	Capital project to replace in 2020
FW	No.2 Transformer	EE	BD223	RBP	Will be replaced with switchgear project 2021
HB	No.1 Transformer	EE	BS223	RBP	Transformers planned to be replaced in 2020
HB	No.3 Transformer	EE	BS233	RBP	Transformers planned to be replaced in 2020

Prior to installing any replacement transformer bushings, electrical tests (DDF, PD, IR) will be undertaken to confirm their serviceability.

4.1.5.3 Performance Analysis

Performance of the ZSS transformers is judged both by the continuity of reliable service and maintenance of acceptable condition such that failures in-service are unlikely.

At this point in time there are nine Zone Substations (BY, COO, CS, ES, FE, FT, HB, NS, SBY & SHM) that will exceed their N-1 cyclic ratings on a 10% PoE day. Of these, two (SBY & FT) will exceed their N secure ratings. To address these contingency risk situations, augmentation projects are planned for both FT and SBY by November 2018. Operating transformers beyond their cyclic ratings is a risk which the business is prepared to take, balancing economics, accelerated ageing and probabilities of failure coupled with customer outage risks.

There have been no explosive/rupture/winding transformer failures since EP No.1 in 2002; and no 66kV bushing physical/explosive failures. Effective maintenance, condition monitoring and proactive condition based planned replacements have achieved this good performance.

Oil condition is recorded and monitored via the Transformer Condition Index. The condition index incorporates a traffic light system where dissolved gas analysis is used to obtain the following parameters: quality, moisture, acidity, dielectric, interfacial tension, furan and presence of copper sulphide. Refer Appendix E.

Important assumptions underpinning oil performance analysis include:

- Samples taken are free of water and other contaminants; and
- Results are continually monitored and actioned accordingly to prevent failure(s)

A power transformer contains a significant amount of paper insulation and its condition varies throughout the transformer winding. Deterioration is at its highest where temperatures are highest, and this occurs within the transformer windings, which is not accessible. As a result, when a transformer is in service the condition within the winding can only be estimated.

Diagnostic testing and historical data are the only means available to determine the condition of the transformer deep within the insulation structure without dismantling the unit.

Important assumptions underpinning paper performance analysis include; PDC/RVM, paper moisture, furan, and paper DP Cyclic testing of 66kV bushings is performed, recorded and monitored. The aim is to identify bushings that present with high DLA readings because of moisture ingress, so replacement plans can be implemented prior to failure.

Planned replacements have been completed as listed in Section 4.1.4.3. This Section also lists planned future replacements. All English Electric bushings will be replaced.

Important assumptions underpinning how transformer 66kV bushing performance are analysed include:

- Testing performed to obtain accurate test results; and
- Results continually updated and monitored so poor test results can be actioned accordingly to prevent failure(s).

The table below lists transformers in the Red zone based on condition monitoring tests. From the Condition Based Risk Management (CBRM) model, the Health Index (HI) column, indicated the condition HI=0 to 4 (Good/Fair), HI = 4 to 7 (Fair/Poor), HI = 7 to 10 (Poor to Bad). Zone Substations (ZSS) transformers at ES and FF have the highest HI indicating transformers are in poor condition. These transformers will be replaced during 2019/2020. All other transformers will continue to be monitored and mitigation will be put in place to treat their condition until replacement.

Table 4-8: Transformers with poor condition test results

ZSS	Tr. No.	Poor condition reason (listed in transformer condition index spreadsheet Appendix E)	Comparative CBRM HI
AW	1	Paper moisture high from PDC/RVM tests	4.43
AW	3	Paper moisture high from PDC/RVM tests	5.75
BD	1	Paper DP low from paper sample	7.36
BD	2	Paper DP low from paper sample	7.71
CN	1	Paper moisture high from PDC/RVM tests +IFT low	5.23
CN	2	Oil quality poor	5.49
COO	1	Copper Sulphide detected in oil	0.78
EP	3	Moisture in oil high	6.66
EP	4	Moisture in oil high	6.05
ES	1	Paper moisture high from PDC/RVM tests	8.29
ES	2	Paper moisture high from PDC/RVM tests	7.91
FF	1	Paper DP low from paper sample + IFT low	8.66
FF	2	Paper DP low from paper sample	8.53
FF	3	Paper DP low from paper sample+ oil quality poor + moisture in oil high	8.53
HB	1	Paper moisture high from PDC/RVM tests + Paper DP low from paper sample + DP low from tests	7.01
NT	1	High moisture in oil	6.66
NT	3	High moisture in oil	6.66
SBY	1	Copper Sulphide detected in oil	1.73
SBY	3	Copper Sulphide detected in oil	2.04

4.1.6 UTILISATION

4.1.6.1 Power Transformer Utilisation – Limitations

The rating of a zone substation is usually limited by the transformer thermal rating. As the transformer is the most expensive item of equipment in a zone substation it is standard practice for the transformer to be the limiting item of equipment. In most cases the summer rating is the predominate case for assessing zone substation limitations.

Almost all of Jemena zone substations can be controlled remotely and as such a 2 hour emergency rating or 10 minute emergency rating can be used.

Transformer ratings are assessed individually and each zone substation will have its own unique rating depending on the rating of the transformers and the degree of load balancing between them. Imbalance in transformer loading with respect to their ratings may also reduce the station rating.

4.1.6.2 Power Transformer Utilisation – Ratings

Zone substations are generally assigned four ratings:

Nominal Rating (N):	This is the peak demand based on a specified hypothetical load cycle in combination with a most onerous ambient temperature cycle.
Cyclic Rating (CR)	This is the permissible daily peak demand to which the transformer(s) may be subjected over a nominated period when a major plant item is out of service. (90 days has been used, being the practical repair period in the event of a major plant failure with no spares)
Limited Cyclic Rating (LCR)	This is the permissible peak demand to which the transformer(s) may be subjected over one daily load cycle, after which the transformer load must be reduced to its CR when a major plant item is out of service.
Two Hour Emergency Rating (2hr ER)	This is the permissible peak demand to which the transformer(s) may be subjected over 2 hours, after which the transformer load must be reduced to its LCR when a major plant item is out of service.

Under system normal operation, zone substations may be operated to the transformer name plate ratings. For a three transformer station with 20/33MVA transformers, this means the station has a nominal maximum rating of 3 x 33 = 99MVA. However depending on other station constraints (eg switchgear rated at 1250A – 47.6MVA@22kV) the station load may not be operated to the N rating. t.

Cyclic ratings can be used for short periods of time as the load is not constant over time. The cyclic rating is higher than the nameplate rating which allows the transformers to be loaded above the nameplate rating for a period of time. The higher the assigned cyclic rating, the shorter the time the transformers can be operated before exceeding safe core temperatures. Some loss of life occurs when the cyclic ratings are used.

The ratings are based on the formulae and temperature/life curve derived from AS 60076-7 with the following assumptions:

Top Oil Temperature Limit	= 105ºC
Hot Spot Temperature Limit	= 140ºC
Maximum Current Limit (cyclic)	= 1.5 times rated current
Maximum Current Limit (limited cyclic)	= 1.65 times rated current
Daily Loss of Life (cyclic)	= 0.03%
Daily Loss of Life (limited cyclic)	= 0.12%

The above ratings apply to newer transformers and caution must be exercised when considering ratings of transformers that old or in known poor condition. Older transformers were manufactured to different specifications and overload temperature rise tests may not have been conducted. It cannot be assumed that transformer cyclic rating is just a multiple of its nameplate rating. Cyclic ratings can only be proven by thermal testing to determine the temperature rise and temperature gradient of the transformer internal configuration.

As an example, if a transformer is loaded at its cyclic rating, each 24 hour of such loading will account for 0.03% of loss of transformer life, i.e, the transformer will have a life of about 10 years. Similarly, if a transformer is loaded at its limited cyclic rating, each 24 hour of such loading will account for 0.12% of loss of transformer life, i.e, the transformer will have a life of about 2.5 years.

In applying these ratings, the philosophy has been that a zone substation can be loaded up to its (N-1) limited cyclic rating provided there was adequate transfer capability to reduce the load on the station to its cyclic rating within 24 hours.

In most contingency situations, however, it is possible to effect load transfers within 2 hours. Hence, the concept of "2 hour emergency rating" has been introduced and applied at critically loaded zone substations to defer capital expenditure.

With the implementation of remote monitoring and control schemes at zone substations and remote switching on the distribution network, shorter time ratings (10 minutes) can be introduced provided procedures are put in place to minimise risk of damage to plant.

10 min Emergency Rating : (N-1) 10 min ER	This is the permissible peak demand to which the zone sub-station may be subjected over a ten minute period, due to an emergency transformer outage. After which the transformer load must be reduced to its (N-1) LCR and further reduced to below its (N-1) CR within 24 hours. These will only be applied to newer transformers

4.1.6.3 Power Transformer Utilisation – Overload Ratings

Overload ratings of stations may be available if remote transformer temperature monitoring is installed at a zone substation.

Unlike the cyclic ratings which take advantage of the rise and fall of the load curve on a cyclic basis and the emergency ratings which utilise a theoretical model to derive a current rating, the overload rating utilises the precise operating temperature and the maximum temperature limitation of the transformer.

Given that the cyclic ratings are based on high ambient temperatures, a contingency during cooler conditions means that potentially higher ratings could be obtained. This is where the overload rating becomes useful with a direct reading of transformer oil temperature.

Some adjustment of the temperature reading would need to be made to account for the fact that the transducers will not be monitoring the 'hot spot' of the transformer.

Note: Lower Hot Spot temperatures (eg 110 ºC - 130 ºC) should be employed for transformers with known high moisture levels as gas bubbles are known to form with consequential increased risk of insulating oil breakdown.

4.1.6.4 Power Transformer Utilisation – Contingency Management

In the event of a fault anywhere between the sub-transmission busbar and the distribution busbars, a transformer can be completely isolated by the automatic protection tripping of the remote 66kV line CB, the 66kV bus tie CB and the 22/11/6.6kV transformer CB, without loss of supply to the 22/11/6.6kV buses. The remaining transformer(s) will carry the station load until operators arrive to assess the situation.

A zone substation with full transformer switching available may be operated at the (N-1) 2 hour emergency rating of the zone substation with one transformer off supply without risk of damage. Within two hours the load must be transferred away or shed on a cyclic basis to reduce the station to the (N-1) LCR. In the case of a long term fault any load in excess of the cyclic rating should be reduced within 24 hours either by further transfers to adjacent stations or increased shedding on a cyclic basis.

The station may be loaded to a (N-1) 10 minute rating provided that an automatic load shedding scheme is in place to transfer the load away rapidly. Stations operating above the 2 hour rating without an automatic load shedding scheme will need to have feeders shed load in order to protect the transformers.

Auto-reclose on the sub-transmission lines reduces the risk of this situation considerably given that a trip of a sub-transmission line is the most probable contingency

Contingency	**Full Transformer Switching Without Line CB's**
Line Fault	A line fault results in loss of a transformer; hence, shedding some load due to overloading may be necessary.
	Full Transformer Switching With Line CB's
Line Fault	A line fault does not result in loss of a transformer; hence no loss of supply to customers.
	Full Transformer Switching Without Line CB's but with Motor Operated Disconnectors (MOD) installed
Line fault	A line fault results in loss of a transformer initially, but operation of MOD allows transformer to be reconnected after faulted line is isolated; hence, shedding some load due to overloading may be necessary then quickly restored.
Transformer Fault	A transformer fault does not result in total loss of supply to customers. However, shedding some load due to overloading may be necessary.

4.1.6.5 Power Transformer Utilisation – Transformer Capacity

The current standard transformer rating is 20/33MVA based on:

20MVA: ONAN (oil natural, air natural)

33MVA: OFAF (oil forced (oil pumps), air forced (fans))

These ratings are further increased to give the cyclic and emergency ratings as above by application of guidelines in Australian Standards 60076-7, Guide to Loading of Oil immersed Transformers.

This generally results in summer CR, LCR and 2hr ER of *(for newer transformers only):*

CR	42MVA
LCR	45MVA
2hr ER	49.5MVA

This is assigned on a station by station basis. Other factors such as *load profile at the substation and* other equipment limitations in the zone substation can reduce these figures.

Older transformers need to be assessed individually taking into account temperature rise figures, cooling and oil flow design and performance to establish cyclic ratings. Refer to Appendix F for individual substation cyclic ratings.

4.1.7 CONTROL EFFECTIVENESS

Controls employed are identified in Section 4.1.2.4 and condition based replacements completed are listed in Section 4.1.4.3 These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table:

Table 4-9: Effectiveness of Existing Controls

Risk Category	Cause/incident	Controls	Incidents in Past Five Years
Health, Safety & environment	Transformer or bushing explosive rupture failure – people safety and or environment impact	Asset Management strategy applied. Replacement transformer & bushing projects completed	Nil
Regulatory & Compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement transformer & bushing projects completed	Nil
Financial	Rectification of failures results in significant (>$1M) unplanned cost	Asset Management strategy applied. Replacement transformer & bushing projects completed	Nil (Minor repairs at AW EP)
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement transformer & bushing projects completed	Nil Majority (but not all) ZSS operate less than N-1

It can be seen that the controls employed, which are the focus of this ACS document, judged by historical performance, confirms that these controls have been effective.

4.1.8 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 monitoring and preventive maintenance, with the aim of achieving at least 50 years of asset life before replacement (although a transformer may be replaced earlier if increased capacity or capacity requirements dictate), given that power transformers typically:

- cost approximately $2.4 million (indicative only based on an estimate for replacing a single transformer with no other works undertaken) to replace for a contained failure and
- incur low operating expenditures due to their high reliability and low-maintenance requirements.

There are 3 feasible lifecycle management options:

- Condition monitoring and preventive/corrective maintenance, with condition and risk based replacement. By managing the transformer load within its design parameters and regular scheduled maintenance, a transformer's life expectancy can exceed 50 years; cyclic testing of 66kV bushings is performed to identify bushings that have some degree of moisture ingress which can lead to bushing failure; and onload tap changer and cooling system maintenance is also performed.
- Preventive/corrective maintenance with fixed, age-based replacement (irrespective of condition). This option is not considered to be cost-effective, as condition monitoring, preventive maintenance, diagnostics and CBRM modelling can be employed to achieve more optimum timing for replacement; and
- Preventive/corrective maintenance and run-to-failure replacement. This is not a realistic option due to the criticality of the assets (power transformers), the long lead-time for replacement, and the significant cost of carrying system spares. A few zone substations are currently operating above N-1 and run-to-failure would directly result in widespread and frequent supply interruptions for up to eight months until a replacement transformer is procured and installed.

4.1.8.1 Lifecycle management

The current asset strategy, involving adequate monitoring and maintenance at an average annual cost of less than $10,000 per transformer, is intended to extend transformer life beyond 50 years.

The decision to replace a 66kV transformer bushing is based on an engineering assessment of the DLA result. The DLA result is assessed using the Tan Delta Result Card. Cyclic testing of 66kV transformer bushings is performed every 5 years to measure the Dielectric Dissipation Factor (DDF) and to identify bushings that have poor insulation condition which is typically caused by moisture ingress.

While planned 66kV bushing replacement is determined and prioritised based on ongoing test results, budget constraints are always also considered.

4.1.8.2 Creation

Working assets in power transformers are effectively created via acquisition, or to meet load demands, or asset replacements.

The specifications with embedded standards employed to enable this asset to meet requirements include:

- Australian and international standards for transformer and substation design;
- Zone substation transformer 66/22 and 66/11 kV specification;
- Zone substation 22/11/6.6 kV power transformer specification;
- Zone substation Primary Plant Design Manual JEN ST 0610; and
- Period contracts for procurement

The standard types and acquisition triggers for power transformers include:

- As part of a new zone substation development;
- As a part of an existing zone substation capacity upgrade; and
- To replace old transformers that have reached end-of-life.

With a lead-time (from the submission of a purchase order to installation) of approximately 8 months, the transformers required due to the first trigger are currently sourced as part of a turn-key project for the entire substation or from period supply contracts. The transformers required due to the second and third triggers are sourced from period supply contracts.

To reduce associated design, construction and installation costs, power transformers have been standardised to two main types; 66/22 kV and 66/11 kV, with the exception of the zone substations at East Preston (EP) at 66/6.6kV, Fairfield (FF) at 22/6.6kV, and North Essendon (NS) at 22/11kV.

Planning for conversion of the EP transformers to 66/22kV is currently being undertaken due to capacity constraints.

A standard design for 22/11/6.6kV transformers was developed for transformer replacements at Fairfield (FF) and North Essendon (NS), as the sub transmission voltage at these zone substations will remain at 22kV for the foreseeable future.

4.1.8.3 Asset Operation and Maintenance

This section provides information about the asset maintenance program, including inspection and testing, preventive maintenance, and reactive and corrective maintenance.

The current asset maintenance program involves:

- Monthly inspection conducted by operational employees;

- Annual inspection conducted by engineering staff;
- Reactive and corrective maintenance;
- Preventive maintenance; - time and condition based and
- Time based condition monitoring.

The level of expenditure required for these four activities will be monitored to ensure it is adequate to maintain transformer performance at the expected levels over the transformer life.

a) Inspection

Zone substations are inspected monthly by operating personnel and annual engineering audits are conducted by the Primary Plant & Distributions Systems group.

Transformer inspection activities undertaken during these site visits include checking for general cleanliness, oil levels, oil leaks, corrosion of tank/cooler/conservator, tank distortion, broken porcelain, tracking on bushings and surge arresters, observing hot spot and top oil temperature indication, operation of auxiliary equipment such as the transformer cooling systems and any unusual noise.

Bushings are closely inspected during class 4 transformer maintenance every 4-6 years. As per the Standard Maintenance Instruction (SMI) the bushings are inspected for physical damage, oil level checked (if applicable), terminations inspected, bushing caps inspected and bushings cleaned accordingly.

b) Reactive and corrective maintenance

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified faults (or both), resulting in the repair of:

- Oil leaks (bushings, tank gaskets, radiators, oil gauges);
- Transformers (replace bushings, repair/replace rusted radiators, repair conservator oil level indicators);
- OLTCs (mechanism failure and diverter switch contact replacement); and
- Auxiliary equipment (defective temperature indicators, fans, and pumps)

Assessment of condition monitoring results can generate tasks such as:

- Regenerate oil to reduce acid levels;
- Oil processing to reduce moisture; and
- Excessive DGA .readings necessitating physical inspections and repair of high resistance connections

c) Preventive maintenance

Transformers and OLTCs are scheduled for preventive maintenance based on:

- Operational duty (the number of tap-changer operations), or
- A maximum time interval of 6 years

Refer to Plant Guidance Instruction/ Standard Maintenance Instruction documents for details of these criteria.

d) Condition-based monitoring

Jemena’s condition-based monitoring programs involve:

- Annual Oil sampling and testing;
- Annual Dissolved gas analysis;

- Degree of polymerisation value is estimated form annual oil samples. However PDC/RVM measurement and paper samples are planned as the need arises;
- Annual Infra-red thermal imaging, and
- High voltage bushing monitoring (DDF) at 5 yearly.

The CBRM model is updated with results to evaluate current condition and predict condition into the future.

For more information about these monitoring programs, see Appendix D.

4.1.8.4 The Zone Substation Transformer Condition Monitoring Index

A transformer's operating life is difficult to directly determine due to different variables, including its fault history, load, operating environment, and age. The Transformer Condition Monitoring Index is a spreadsheet (see Appendix E) containing condition data used to make engineering assessment of its condition and potential for life extension. This data is also applied in the Condition Based Risk Management (CBRM) model, refer to Appendix L.

The zone substation transformer condition monitoring index is:

- Maintained to monitor transformers, schedule testing, and determine an end-of-life;
- Continually updated with information about polarisation and depolarisation current (PDC), recovery voltage measurements (RVM), dissolved gas analysis (DGA), and electrical test results; and
- Bushing Dielectric Dissipation Factor (DDF), performed every 5 years, with results listed as a bushing health index.

4.1.8.5 Asset Replacement/Disposal

Replacement of zone substation transformers prior to failure is only considered when all cost effective maintenance and life extension options have been considered and condition monitoring has indicated that the transformer is likely to fail electrically, thermally or mechanically and the deterioration trend cannot be halted or reversed. The CBRM modelling supports the planned replacement in the capital replacement program which has been optimised according to acceptable risk criteria to meet performance targets. From table 4-8, the CBRM model, Zone Substations transformers at ES, FF and HB have the highest HI indicating transformers are in poor condition. These transformers will be replaced during 2019/2020. All other transformers will continue to be monitored and mitigation will be put in place to treat their condition until replacement.

While planned power transformer replacement is determined and prioritised based on ongoing testing results, resource constraints and other network requirements (such as capacity constraints) must also be considered.

If a 66kV transformer bushing presents very poor Tan Delta results the bushing will be replaced within 3 months. During this time, the bushing condition will be assessed to determine if it is safe for the transformer to remain in-service. Otherwise bushing results are recorded and replacement prioritised accordingly.

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how Jemena prioritises and optimises its investments.

Historical capital expenditure (2002 - 2017)

Table 4-10 lists information about historical CAPEX for the period 2002 to 2017.

Table 4-10: Transformer Replacement History from 2002 to 2017

Year	Qty.	Transformer	Reason for Replacement
2002	1	EP No.1	Transformer winding insulation failure resulting from an external feeder fault. Poor DP of 300.
2006	1	EP No.2	Replaced due to poor condition of winding insulation.
2009	1	YTS* No.2	No.2 transformer removed from service due to poor condition of HV bushings as a result of cooling system failure.
2012	2	PV	No.1 and No.2 transformers were replaced due to poor condition and to meet future load demand.
2014	2	YTS* No.1 and No.3B	YVE zone substation was built with two new 20/33 MVA transformers to replace the two old transformers at YTS zone substation whose winding insulation was in poor condition.
2017	3	NS No.1, 2 & 3	No.1, 2 & 3 transformer were replaced due to their poor condition

* The Yarraville Terminal Station (YTS) has been replaced by the Yarraville Zone Substation (YVE).

Table 4-11 lists historical 66kV bushing replacements

Table 4-11: 66kV Bushing Replacement History from 2002 to 2017

Year	Qty.	Transformer	Reason for Replacement
2013	3	AW No.1	Poor DDF results
2014	3	AW No.3	Poor DDF results
2014	3	AW No.3	Poor DDF results
2014	3	BY No.1	Poor DDF results
2014	3	BD No.1	Poor DDF results
2013	3	BD No.2	Poor DDF results
2014	3	BD No. 3	Poor DDF results
2013	3	CN No.1	Poor DDF results
2013	3	CN No.2	Poor DDF results
2014	3	ES No.1	Poor DDF results
2016	3	FW No. 1	Poor DDF results
2017	1	SBY No.2	Poor DDF results

Table 4-12 lists proposed replacements for the next thirteen years from 2018 to 2037

In line with the CBRM model (refer table 4-8), the transformer replacement at ES and FF Business Cases have been approved and site construction has commenced. The transformer replacement projects for HB and BD are being prepared.

Table 4-12: Proposed Transformer Replacements from 2019 to 2037

Historically 9 transformers have been replaced between 2002 and 2017. Looking forward, a further 6 transformers will be replaced from 2019 to 2021.

Transformer	Estimated Replacement Timeframe	Reasons for Replacement	Comments
FF No.1 and No.2	2019	Poor DP, Fair oil quality & Noise level issues	Business Case approved[5]. Construction in progress.
ES No.1 and No.2	2019	Poor DP	Business Case approved[6]. Construction in progress.
HB No.1 and No.3	2020/21	Poor DP, Fair oil quality, high paper moisture	Gating process has commenced
BD No.1 and No.2	2021/22	Poor DP	Paper sample and full transformer testing to continue. One transformer planned for replacement.
NT No.1 and No.3	2027/28	Poor DP, fair oil quality, high moisture.	Paper sample and full transformer testing to continue.
AW No.1 and No.3	2028/29	Poor DP, fair oil quality, high moisture	Paper sample and full transformer testing to continue.
CN No.1 and No.2	2030/31	Poor DP, fair oil quality, high moisture	Paper sample and full transformer testing to continue
PV No.3	2031/32	Poor DP	Paper sample and full transformer testing to continue.
BY No.1	2032/33	Condition	Prediction using CBRM
FE No. 2	2034/35	Condition	Prediction using CBRM
FW No.1 & No.2	2036/37	Condition	Prediction using CBRM

The replacement at FF includes relocation of the 22kV switchyard to allow the new transformers to be installed whilst the old transformers are still in service. Two 12/18MVA transformers are planned for replacement while retaining the No.3 transformer as a hot spare.

The replacement at Essendon includes the installation of the third transformer bay and the replacement of No.1 and the No.2 transformers with a new 66/11kV transformer.

The replacement at Heidelberg includes the installation of the third transformer bay and the replacement of No.1 and the No.2 transformers with a new 66/11kV transformer.

[5] FF business case can be accessed here.
[6] ES business case can be accessed here.

Table 4-13 : Proposed 66kV Bushing Replacements from 2019 to 2037

Transformer	Estimated Replacement Timeframe	Reasons for Replacement	Comments
AW No.1 and No.2 Transformer Neutral bushings	2019	Poor Tan Delta results	Replace with ABB GSA-OA
FT No.1 Transformer bushings	2019	English Electric RBP bushings	Replace with ABB GSA-OA
EP No.1 Trans Red and Blue Phase bushings	2019	Poor Tan Delta results	Red & blue phase
PV No.3 Transformer	2020	Poor Tan Delta results	Red, White and Blue Phase Bushings

Typically, when power transformers are retired or replaced, they are drained of approximately 17,000 litres of oil, which is tested and disposed (recycled) of separately. In order for the transformer to be fit for transportation, a certificate must be obtained to ensure the transformer is free of PCBs so it can be appropriately transported.

Before disposal, the Primary Plant group assesses transformers for retainable spare parts. If similar plant exists, all applicable parts (bushings, tap-changer parts, conservator gauges etc.) will be tested and retained as spares.

Paper samples are tested at the time of disposal to provide information about transformer ageing for reference purposes.

Transformer 66kV Bushings are tested for PCB contamination and disposed of accordingly at Tullamarine depot via the dedicated bund. Reference to the Waste Management Procedure JEM HSE PR 0016.

4.1.8.6 Future Improvements

Jemena's technology strategy involves investigating new technologies to maintain network reliability and reduce costs and currently involves the following:

- The Wilson 'Dynamic Rating, Monitoring, Control and Communications (DRMCC)' system has substantially improved transformer control functionality and provided greater flexibility for parallel transformer operation. The option of retrofitting DRMCC to existing transformers has been evaluated and is being implemented in conjunction with certain zone substation augmentation projects. The cost of this functionality is minor when compared to the total augmentation cost. In addition, the use of DRMCC in conjunction with SCADA provides the opportunity for on-line monitoring of winding, oil and bushing condition in real time.
- Due to increasing environmental sensitivity, a new option to replace mineral oil in existing transformers with a synthetic, high-temperature fluid (called FR3) is now available. This fluid is still being evaluated and tested by the industry. FR3 is almost five times more expensive than mineral oil, but depending on how it is classified by the EPA, its use could eliminate the need for oil containment, as well as reducing the fire risk associated with a transformer fault. This should result in lower installation however a full economic evaluation will be carried out before adoption;
- Vacuum interrupter type 'in-tank' tap-changers are now being specified for transformers. These tap-changers use vacuum interrupters for the diverter switches, so no switching of current occurs in oil. This means there is no accumulation of arcing products associated with the tap-changer, enabling installation of the entire tap-changer in the tank with the transformer core

and coils. This results in a cheaper transformer construction cost, and the elimination of the need for routine tap-changer maintenance, reducing the transformer's life cycle cost;

- On-line monitoring of oil/insulation system condition of the older population of transformers with poor condition and high risk identified using the CBRM model. Utilising the functionality of existing DRMCC installations, online modules can be purchased and control room protocols established to monitor transformer condition 24/7. The interface modules include:
  - DGA;
  - 66kV bushing PD; and
  - OLTC tap changer temperature monitoring

  An evaluation of online monitoring systems is currently in progress to determine a suitable standard for Jemena and identify which asset would benefit from this initiative.

- Fibre optic sensors for accurate monitoring of transformer hot spot will be employed for all future JEN transformers.
- The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information concerning transformers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote the efficiency and reliability of substation management.

4.1.9 INFORMATION

Jemena's AMS provides a hierarchical approach to understanding the information requirement to achieve Jemena's business objectives at the Asset Class. In summary, the combination of Jemena's Business Plan, the individual Asset Business Strategy (ABS) and Asset Class Strategy (ACS) all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives (**Table 4-14**).

Table 4-15 identifies the current and future information requirements to support the Sub Asset Class critical decisions and their value to the Asset Class. **Table 4-16** provides the information initiatives required to provide the future information requirements identified in

Table 4-15. Included within this table is the risk to the Sub Asset Class from not completing the initiative.

All of the information required by the transformer Sub Asset Class is available within Jemena's current business systems.

Table 4-14: Transformer Business Objectives and Information Requirements

Business Objective	Jemena Information Sources	Externally Sourced Data
Maintain Safety, availability and reliability of transformers	SAP DrawBridge Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI)	VESI primary plant committee. Alerts – from DB's and Government Organisations and manufacturers. Manufacturing manuals. AS/IEC standards.

Table 4-15: Transformer Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Transformer - Asset Creation	Specifications and tender responses Zone Substation Primary Design Standard New asset project progress reporting. Completion recorded in SAP Asset register in SAP		High: Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements

Maintain functionality of the Transformer via Inspections, and audits	Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• Basic specification
	  ○ Voltage
	  ○ Current
	• Location: Zone substation name
	• Address
	
	Condition Monitoring
	Maintenance reports
	Test reports
	
	Performance history:
	• Daily situation reports
	• Investigation reports (ECMS)
	• Plant defect reports
	
	DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts
	
	SMI's – (Standard maintenance instruction)
	
	SAP notifications and work orders activities performed and components replaced.
	
	Details of work completed recorded in SAP
		Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.
		Photograph transformer nameplate and attach to SAP equipment.
		Determine transformer loading guideline.
		Access all information via electronic tablet in the field.
		Update asset data in SAP for missing data.
			High: Regulated to maintain supply reliability, safety and quality of supply

Maintain functionality of the Transformer	Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP.	Results are recorded in SAP and standard job report (fitters report)	High: Regulated to maintain supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
via Preventive Maintenance	Scheduled task description, timing and completion recorded in SAP; SMIs held in Sharepoint, Policies & Forms. Manufacturers maintenance manuals SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP OPEX & CAPEX cost reporting recorded in SAP	scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment). Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	reliability, safety and quality of supply
Maintain functionality of the Transformer via Condition Monitoring	Condition monitoring tasks, schedule in SAP and results stored in proprietary test equipment data base SAP Scheduled task description, timing and completion recorded in SAP. Outputs from condition monitoring analysis.	Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	High: Regulated to maintain supply reliability, safety and quality of supply

Respond to Transformer defects / faults to restore equipment operationally. Perform corrective maintenance.	Alerted via JEN Control Room or situation report.
	Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• basic specification
	    ○ Voltage
	    ○ Current
	• Location: Zone substation name
	• Address
	SAP notifications and work orders activities performed and components replaced.
	Details of work completed recorded in SAP
	Condition Monitoring Maintenance reports & Test reports
		Although hard copies of manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in in Drawbridge. Manufactures manuals for older assets may not be available.
		Access all information via electronic tablet in the field.
		All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.
			High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports. DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts Asset failure details and investigation reports. Stored in ECMS OPEX & CAPEX cost reporting recorded in SAP		
Transformer – Condition Based Risk Management (CBRM)	CBRM analysis Health Index Held by Primary Plant Distribution Systems Group		High: Regulated to maintain supply reliability, safety and quality of supply
Transformer – Rating suitable for load demand	ZSS load forecast in ECMS Published annual Distribution Planning Report available on Jemena website	Determine transformer loading guideline	High: Regulated to maintain supply reliability, safety and quality of supply
Asset Class Strategy Review	Condition data Fault/failure data Maintenance & replacement costs AMS		Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-16: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph transformer nameplate and attach to SAP equipment Determine transformer loading guideline Access all information via electronic tablet in the field.	To improve analysis and decision making. Asset data available from business systems saving on site trips. To utilize full emergency rating of a transformer during	Poor efficiency in accessing asset data and delayed response when transformer full ratings are required.	Transformer emergency rating and recommendation guideline will ensure accurate assessment and improved understanding in Asset management. Asset Data as per RCM and SAP requirements.

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Update asset data in SAP for missing data.	system abnormal operating conditions.		

4.2 ZONE SUBSTATION CIRCUIT BREAKERS

4.2.1 Introduction

This section includes information about the type and specifications of the circuit breakers (metalclad buses, arc fault containment to current Australian standard/IEC standard) in service across the Jemena Electricity Network (JEN).

Circuit breakers (CBs) are devices that operate automatically to interrupt current flows under network fault conditions. The main function served by circuit breakers is network fault isolation, enabling the distribution network to be operated in order to safely, and with minimal customer interruptions, construct, maintain, repair, and respond to faults on the distribution network.

There are a total of 488 circuit breakers in operation across JEN; this number is made up of 62 66kV CBs, 277 22kV CBs, 92 11kV CBs and 57 6.6kV CBs. The 66kV and 22kV CBs are installed in a mix of indoor and outdoor environments; with all the 11 and 6.6 kV CBs being indoor.

A number of different insulating/interrupting mediums have been used in CBs which are indicative of the era in which they were manufactured. Bulk oil was typically used from 1940s to 1960s, minimum oil was used from 1960s to 1980s with vacuum interrupters used in distribution voltage CBs from late 1970s to present day and SF6 gas used at all voltages from 1980s to present.

Outdoor CBs are either dead tank (DT), where metal enclosure(tank) is at earth potential with HV connections via bushings (bulk oil & DT SF6 plus a few vacuum CBs in metal enclosures); or live tank, where pole housings are single phase insulated (porcelain) with HV connections at top of poles; live voltage and mechanisms at earth potential

Indoor CBs are arranged as a metal enclosed switchboard, containing an air insulated bus, CTs, VTs and cable terminations and normally rackable CBs, which are either bulk oil, minimum oil, vacuum or SF6 types. Older switchboards (typically with BO CBs) are not of arc fault containment design, whilst newer (late 1970s onwards) switchboards are.

A typical zone substation has one or more 66kV CBs and between eight to twelve distribution feeders at 22kV, 11kV or 6.6kV distribution voltages supplying up to 30,000 residential customers.

4.2.1.1 Asset Specification

Table 4-17 lists the manufacturer, type, voltage, quantify and the installation location (zone substation) for this asset class.

Table 4-17: Circuit Breaker Information

CB Manufacturer & Type	Voltage	Quantity	Zone Substation
ABB 72PM40	66kV	2	BMS, TMA
ABB EDF SK 1-1	66kV	7	BD, CN, SSS
ABB RMAG	22kV	2	BD
ABB PASS MOO	66kV	4	BMS, TMA

CB Manufacturer & Type	Voltage	Quantity	Zone Substation
ABB VBF 36	22kV	1	BD
ABB VD4	11kV 22kV	74 39	ES, FT, HB, NS, PV BD, BMS, SHM, ST, TMA
AEI LG4C	66kV	10	CN, CS, EP, FE, FW, HB, NH, NT
ALSTOM S1-72.5F1	66kV	2	BY
ALSTOM DT1-72.5 F1	66kV	19	AW, COO, EPN, ES, PV, YVE, MAT, SBY
AREVA DT1-72.5 F1	66kV	1	SHM
ASEA HKEYC	66kV	1	EP
ASEA HLC 2000	66kV	2	CN, VCO
ABB HBS24	22kV	13	ST
CG 30-SFGP 25A	22kV	9	AW, CN, YVE
EMAIL WR 345GC	22kV	51	AW, BD, BLT, CN, FE, FW
EMAIL J18	6.6kV	23	EP
ENGLISH ELECTRIC OLX	6.6kV	13	EP
MV SB14	22kV	27	FE, FW
SCHNEIDER AD4/SF-1	22kV	13	BY
SCHNEIDER SB6-72	66kV	3	MAT
SIEMENS 3AF	22kV	19	CN, TH
SIEMENS 3AH	22kV	4	NH, NS
SIEMENS 3AH1164	11kV	5	NS
SIEMENS 3AH5204	6.6kV 11kV	21 12	FF NS
SIEMENS 3AH5273	22kV	49	EPN, NT, YVE, SBY
SIEMENS 3AH5283	22kV	33	COO, EPN, NH, NT, SHM, YVE
SIEMENS 3AP1-DT	66kV	6	COO, NH, SBY, SHM
SIEMENS 3AP1FG	66kV	1	FE
SIEMENS 8BK20	22kV	7	SHM
S & S HPFC 409K	66kV	3	SBY, ST, TH
S & S HPTW306-FS	22kV	29	CS, FE, FW, NH

4.2.1.1.1 Age Profile

Figure 4-10 and 4-11**Error! Reference source not found.Error! Reference source not found.** shows the circuit breaker age profile and the percentage of population in nominated age groups.

Figure 4–9: Circuit Breaker Age Profile

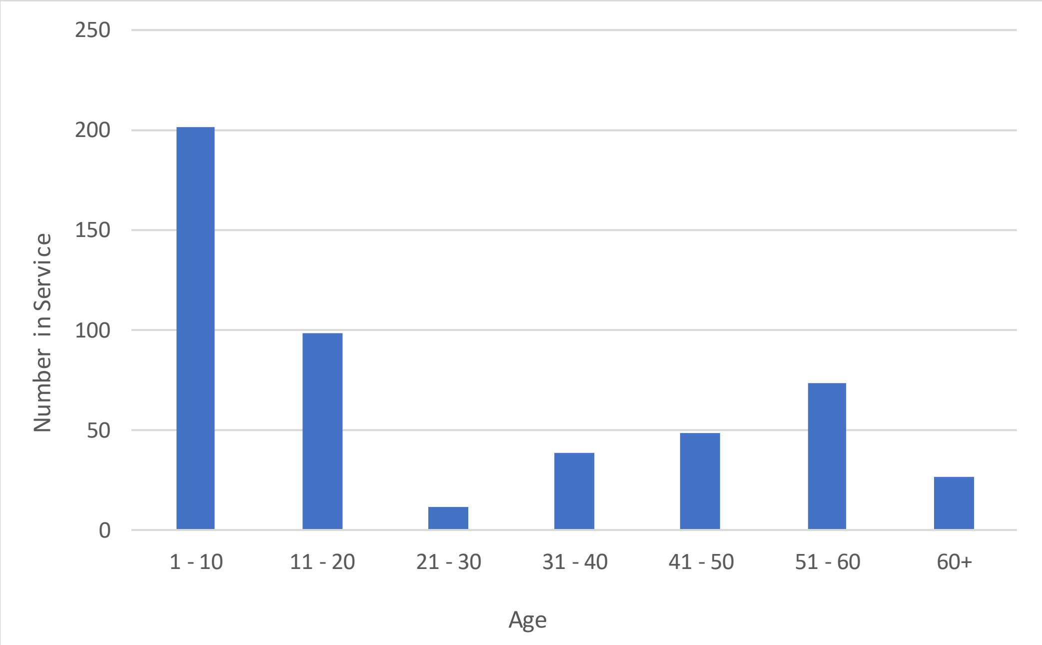
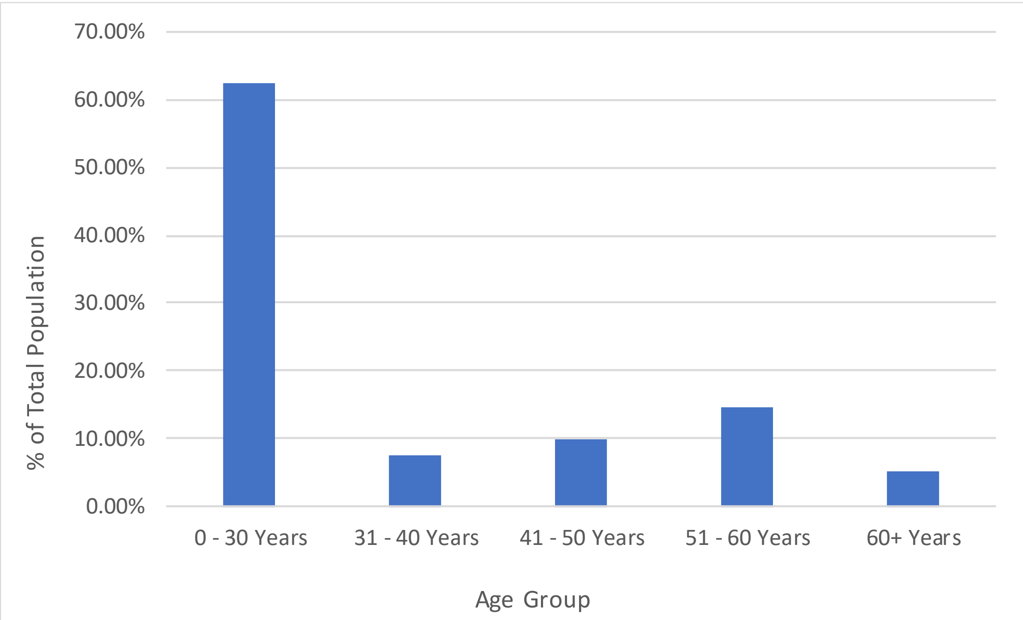


Figure 4–10: Circuit Breaker Age vs % of Total Population



Of the various circuit breaker age groups:

- 101 are over 50 years old, representing 20% of the total population (which will be prioritised for replacement using a condition and risk-based approach);
- 49 are between 40 and 50 years old, representing 10% of the total population (the ageing condition of which will be closely monitored as they approach and exceed 50 years).

4.2.2 RISK

This section includes information about circuit breaker risk profiles, how criticality is established, the risks posed by circuit breaker 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 facing affected zone substations.

This information specifically involves:

- Asset class criticality score (sub asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Condition Based Risk Management (CBRM) for identifying assets approaching end of life;
- Existing controls;
- Asset Spares;
- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

The quantification of risk and the risk trends is important for providing top-down justification for the circuit breaker program of works.

The risk assessment for circuit breakers is filed in JCARS[7]. A summary of these risks relevant to circuit breakers is provided in this section.

Risks for this asset class and the probability this will occur include:

- Regulatory non-conformance, likelihood is rare;
- Health and safety issues (equipment failure), likelihood is unlikely;
- Environmental issues (equipment failure), likelihood is unlikely;
- Financial Impact (loss of supply), likelihood is unlikely;
- Operational (loss of supply), likelihood is rare; and
- Reputational risk, likelihood is rare.

The potential consequences resulting from these faults can include:

- Serious – possibility of general regulatory queries;
- Severe – Single permanent partial disability;
- Serious – On-site release of pollutants with minimal impact;
- Serious – Loss of supply, Replacement of equipment (switchboard, bus, 66kV CB) is expected to be >100k and <$1M (excludes STIPIS, direct costs only) due to plant replacement and collateral damage;
- Severe – Loss of supply to 3,000 customers for greater than 24 hours while switching transfers take place. Possible rotational load shed.

Emerging risks for this asset class include:

- Ageing population;
- Deteriorating insulation condition of busses and CB bushings of indoor switchboards;

[7] For more information on JCARs please click here.

- Damage due to vandalism, and
- Non-availability of components for old CBs & switchgear from suppliers/manufacturers.

4.2.2.1 Criticality

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub asset class level by following the Asset Criticality Assessment Procedure (JEM AM PR 0016). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of Jemena'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.

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures.

For severe circuit breaker failures that cannot be repaired within 24 hours; the location within the network determines the impact on supply to customers. The following table demonstrates the various scenarios.

Table 4-18: Scenarios Depicting Strategic Failures

ZSS configuration	Failure Item	Protection trips to isolate fault	Status post trips	Customer impact	Failure category
3 transformer, no 66 kV line CBs	66 kV Bus-tie CB	Remote end line CB & Other 66 kV B-T CB	2 transf OOS; 1 transf in service, may be overloaded	Likely to be some load shedding	Serious
2 transformer, no 66 kV line CBs	66 kV Bus-tie CB	Both remote end 66 kV line CBs	Both transf OOS initially, then restored after fault isolated	All customers off supply initially, then restored after fault isolated	Serious
3 transformer, with 66 kV line CBs	66 kV line CB	Remote end line CB & 66 kV B-T CB; 22/11 transf CB	1 transf OOS	All Customer still on supply	Serious
3 transformer, with 66 kV line CBs	66 kV Bus-tie CB	66 kV line CB & other B-T CB; 2 22/11 kV transf CBs	2 transf OOS; 1 transf in service, may be overloaded	Likely to be some load shedding	Serious
2 transformer, with 66 kV line CBs	66 kV line CB	Remote end line CB & 66 kV B-T CB; 22/11 transf CB	1 transf OOS	All Customer still on supply	Serious
2 transformer, with 66 kV line CBs	66 kV Bus-tie CB	Both 66 kV line CBs	2 transf OOS initially, then restored after fault isolated;	All Customers off supply initially, then restored after fault isolated	Serious
3 transformer	22/11 kV transf CB	22/11 kV B-T & 66 kV B-T	1 transf OOS & 1 Bus OOS	Customers from 1 bus off supply	*Serious or **Strategic**

ZSS configuration	Failure Item	Protection trips to isolate fault	Status post trips	Customer impact	Failure category
3 transformer	22/11 B-T CB	2 transf CBs & other 22/11 kV B-T CB	2 buses OOS	Customers from 2 buses off supply	*Serious or **Strategic**
3 transformer	22/11 kV Feeder CB	22/11 kV B-T & transf CBs	1 bus OOS	Customers from 1 bus off supply	*Serious or **Strategic**
2 transformer	22/11 kV transf CB	22/11 kV B-T, 66 kV B-T & remote end 66 kV line CB	1 transf OOS & 1 bus OOS	Customers from 1 bus off supply	*Serious or **Strategic**
2 transformer	22/11 B-T CB	2 transf CBs	2 buses OOS	All Customers off supply	*Serious or **Strategic**
2 transformer	22/11 kV Feeder CB	22/11 kV B-T & transf CBs	1 bus OOS	Customers from 1 bus off supply	*Serious or **Strategic**

* For outdoor substation it is likely the faulted CB could be isolated and supply restored to the bus within 2 hours. For indoor it would depend if bus was damaged or just the CB which could be racked out & removed. If bus is damaged it would certainly take greater than 24 hours to restore supply.

In summary major failures of any distribution voltage (22/11/6.6 kV) circuit breakers will impact customers. Failures of sub transmission circuit breaker have a greater customer impact in 2 transformer zone substations compared to 3 transformer substations.

The circuit breaker has an asset criticality score of AC4 (High) due to operational and health and safety consequences associated with failures, as presented below:

- high replacement cost (approximately $500k for one 11kV or 22kV bus);
- high strategic impact on customer supply;
- long lead time for repair or replacement (typically 8-16 weeks for indoor), and
- high consequence of failure.

Circuit breakers contribute to JEN overall network reliability and Service Target Performance Incentive Scheme (**STPIS**) via the minimisation of customer numbers off supply during the event of an outage, or planned or unplanned maintenance. Therefore, a CB failure to operate can adversely affect the ability to operate the network and have serious consequences for public and personnel safety.

The circuit breaker asset group contains 2 major categories of CBs, these being Sub-transmission CBs and HV distribution CBs. Some zone substations have both sub transmission line CBs and Bus-tie CBs whilst others just have Bus-tie CBs. Should a line fault occur and the sub transmission CB fail to operate consequences can range from loss of redundancy with no outage to whole zone substation off supply.

Table 4-19: Sub-transmission Line Outage Impact – with Line CBs

Substation with sub-transmission line CBs		Proportion of customers off supply	
Failure asset	**Impact**	**2 transformer substation**	**3 transformer substation**
Line CB	Outage of one transformer	Nil	Nil

Bus-tie CB	Outage of two transformers	100%	Overloading of the remaining transformer will lead to load shedding

Table 4-20: Sub-transmission Line Outage Impact – without Line CBs

Substation without sub-transmission line CBs		Proportion of customers off supply	
Failure asset	**Impact**	**2 transformer substation**	**3 transformer substation**
Bus-tie CB	Outage of two transformers	100%	Overloading of the remaining transformer will lead to load shedding

The impact of a HV distribution CB failure will be dependent on its position within the network configuration. The following CB function and consequences are listed to demonstrate impact of a CB failure to operate assuming it was expected to interrupt a fault.

Table 4-21: HV Distribution CB Outage Impact

		Proportion of customers off supply	
Failure asset	**Impact**	**2 transformer substation**	**3 transformer substation**
Transformer CB	Outage of transformer and whole bus	50%	33%
Bus-Tie CB	Outage of two buses	100 %	67%
Feeder CB	Outage of one bus	50%	33%

Therefore the criticality of an individual circuit breaker will be dependent on it position in the electrical network. In all cases however, much greater outages will result from the non-operation of a HV distribution CB. These resultant impacts will also depend on the number of customers and load being supplied.

Criticality is further assessed for individual circuit breakers utilising a condition based risk model (CBRM). Condition Based Risk Management (**CBRM**), which was introduced for JEN circuit breakers in 2014, is utilised to predict condition into the future (Health Indices) and estimate Probability of Failure. These tools are utilised to indicate required changes to asset management plans, to develop asset investment plans using existing asset data and other information and determine when end-of-life replacement will be required. Assets with a higher health index score are targeted for further analysis before imminent replacement. For further information on CBRM, it's inputs and outputs and methodology please refer to Appendix L.

4.2.2.2 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 Critical Spares Assessment Procedure (JEM AM PR 0015). It was determined that adequate circuit breaker component spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team. Spare 66kV, 22kV, 11kV and 6.6kV circuit breakers are also available.

JEN has various types of spare breakers and components for 22kV/11kV/6.6kV CBs and some bus components and one spare for 66kV CBs. Capital projects have been/will be initiated to replace CBs in poor condition and this will address some of the spares issue. JEN however does not have full complement of spares for every circuit breaker or bus on the network.

System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub transmission line due to a CB failure.

Critical Spares Assessment Procedure (JEM AM PR 0015) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I.

Furthermore when assets are retired from service consideration is given to retaining components or entire asset as spares to service existing aging fleet.

4.2.2.3 Failure Modes

Circuit breakers are installed to fulfil critical functions associated with the safe and reliable operation of the HV network. Circuit breakers can experience tripping defects and in rare circumstances catastrophic failure can occur.

The dominant circuit breaker failure modes that impact on the reliability of the network are as follows:

- failure to insulate due to lightning, over-voltages due to switching, animals and birds or water penetration;
- failure to interrupt or make fault currents;
- failure to carry load due to high resistance connections resulting in thermal overheating; and
- failure to trip due to mechanism problems that prevent the CB from opening or may result in slow operation. This will cause back up protection to operate which may result in the loss of supply from a bus or whole zone substation, and the CB may be damaged.

4.2.2.4 *CBRM Health and Risk Analysis*

Initial CBRM results indicate that the current (Year 0) health index is as shown in Table 4-22. . A total of 85 circuit breakers have been identified to be in poor condition (HI > 7) with a higher probability of failure.

These circuit breakers are located at the following locations.

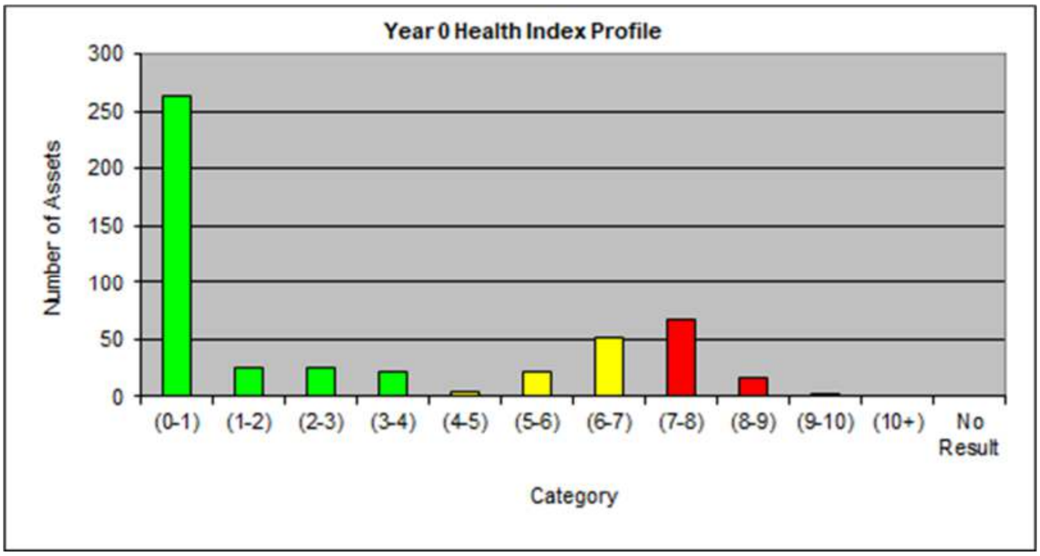
Table 4-22: CBRM Output for Circuit Breakers – Year 0

ZSS	Voltage (kV)	Qty.	Manuf.	Model	HI range	Comment
FW	22	1	Email/WR	345GC	7.98	Planned replacement 2019/20
FW	22	16	MV	SB14	7.01 – 8.06	Planned replacement 2019/20
FE	22	11	MV	SB14	7.01	Planned replacement 2020/21
EP-A	6.6	2	Email	J18 -LC	7.49 – 8.53	To be retired 2021
EP-A	6.6	2	EE	OLX	8.53 – 8.80	To be retired 2021
EP-B	6.6	5	Email	J18 -LC	8.53 – 9.08	To be retired 2022

ZSS	Voltage (kV)	Qty.	Manuf.	Model	HI range	Comment
FW	22	1	Email/WR	345GC	7.98	Planned replacement 2019/20
FW	22	16	MV	SB14	7.01 – 8.06	Planned replacement 2019/20
FE	22	11	MV	SB14	7.01	Planned replacement 2020/21
CN	22	12	Email / WR	345GC	7.98 – 8.25	Switchyard replacement tentatively 2022/23
AW	22	13	Email/WR	345GC	7.98 – 8.25	Switchyard replacement tentatively 2026/27
BD	22	18	Email/WR	345GC	7.98 – 8.25	Switchyard replacement tentatively 2027/28
NH	22	3	S & S	HPTW306-FS	7.15 – 7.70	Switchboard replacement tentatively 2028/29
BLTS	22	2	Email/WR	345GC	8.25	22kV MB FDR CB replacement tentative 2029

Total risk for all failure scenarios at Year 0 is calculated to be $6.65M.

Figure 4–11: Year 0 Health Indices



If asset replacement is deferred until 2023 (Year 5) the health index changes as shown in Figure 4–12. A total of 144 circuit breakers will be in poor condition (HI > 7) with the associated higher probability of failure.

These assets are located at the following locations.

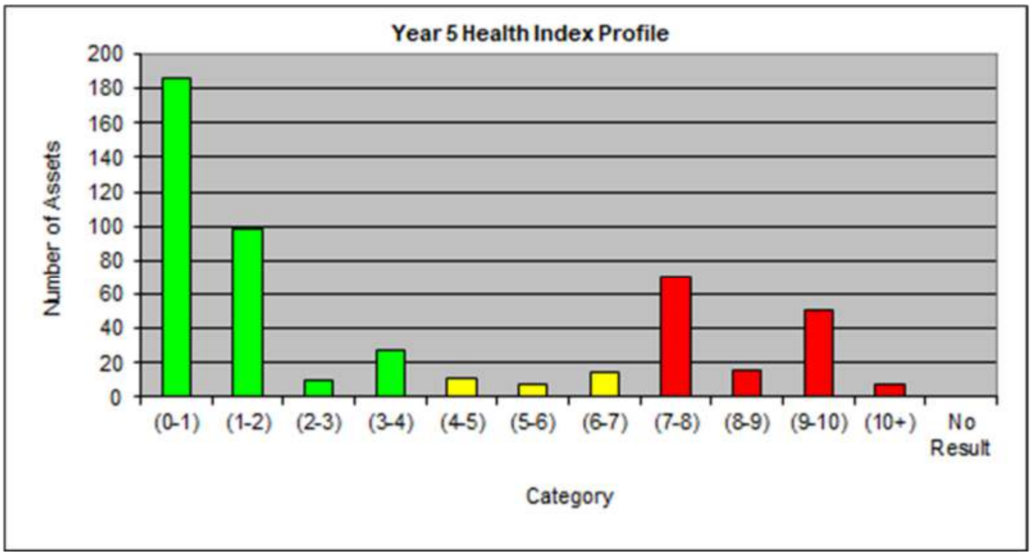
Table 4-23: CBRM Output for Circuit Breakers – Year 5

ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ Year 5
AW	22	14	Email/WR	345GC	7.26 – 9.81
BD	22	18	Email/WR	345GC	9.40 – 9.84

ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ Year 5
BD	66	2	ASEA	HKEYC	7.08
BLTS (MB FDRs)	22	2	Email/WR	345GC	9.72 – 9.75
CN	22	12	Email/WR	345GC	9.56 – 9.91
CN	66	1	AEI	LG4C	7.81
CS	22	8	SPRECHER & SCHUH	HPTW306-FS	7.25 – 8.09
EP-A	66	1	ASEA	HKEYC	7.10
EP-A	66	2	AEI	LG4C	7.81
EP-A	6.6	4	Email	J18 -LC	7.13 – 10.42
EP-A	6.6	13	EE	OLX	7.12 – 10.61
EP-B	6.6	16	Email	J18 -LC	7.47 – 11.10
FE	22	11	MV	SB14	7.81 – 8.67
FE	22	1	Email/WR	345GC	8.04
FE	66	2	AEI	LG4C	7.93
FW	22	2	Email/WR	345GC	7.60 – 9.63
FW	22	16	MV	SB14	7.81 – 9.06
FW	66	2	AEI	LG4C	7.96
HB	66	1	AEI	LG4C	7.84
NH	22	10	SPRECHER & SCHUH	HPTW306-FS	7.56 – 11.55
NT	66	1	AEI	LG4C	7.29
SBY	66	2	ASEA	HLE 72.5/800B	7.06
YVE	22	1	Crompton Greaves	30-SFGP-25A	7.22

Total risk for all failure scenarios at Year 5 is calculated to be $9.60M.

Figure 4–12: Year 5 Health Indices



If circuit breaker replacement is deferred until 2027 (Year 10) the health index changes as shown in Figure 4–13. A total of 169 circuit breakers will be in poor condition (HI > 7) with the associated higher probability of failure.

These assets are located at the following locations.

Table 4-24: CBRM Output for Circuit Breakers – Year 10

ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ year 10
AW	22	16	Email/WR	345GC	7.97 – 11.82
AW	22	3	Crompton Greaves	30-SFGP 25A	7.55 – 8.82
BD	22	18	Email/WR	345GC	11.09 – 11.74
BD	66	2	ASEA	HKEYC	8.28
BLTS (MB FDRs)	22	2	Email/WR	345GC	11.45 – 11.52
CN	22	12	Email/WR	345GC	11.45 – 11.90
CN	22	1	Crompton Greaves	30-SFGP 25A	8.44
CN	66	1	AEI	LG4C	9.25
CS	22	13	SPRECHER & SCHUH	HPTW306-FS	7.90 – 9.92
CS	66	1	AEI	LG4C	7.63
EP-A	66	1	ASEA	HKEYC	8.33
EP-A	66	2	AEI	LG4C	9.25
EP-A	6.6	4	Email	J18 -LC	8.47 – 12.75
EP-A	6.6	13	EE	OLX	8.38 – 12.80
EP-B	6.6	19	Email	J18 -LC	7.84 – 13.57

ZSS	Voltage (kV)	Qty.	Manufacturer	Model	HI @ year 10
FE	22	11	MV	SB14	8.71 – 9.75
FE	22	1	Email/WR	345GC	10.12
FE	22	1	SPRECHER & SCHUH	HPTW306-FS	7.80
FE	66	1	AEI	LG4C	9.68
FW	22	2	Email/WR	345GC	9.57 – 11.62
FW	22	16	MV	SB14	8.71 – 10.19
FW	22	2	SPRECHER & SCHUH	HPTW306-FS	7.53 – 7.80
FW	66	2	AEI	LG4C	9.52
HB	66	1	AEI	LG4C	9.31
NH	22	13	SPRECHER & SCHUH	HPTW306-FS	8.05 – 11.55
NH	66	1	AEI	LG4C	8.31
NT	66	1	AEI	LG4C	8.74
SBY	66	2	ASEA	HLE 72.5/800B	8.23
YVE	22	1	Crompton Greaves	30-SFGP 25A	11.55

Total risk for all failure scenarios at Year 10 is calculated to be $14.90M.

Figure 4–13: Year 10 Health Indices

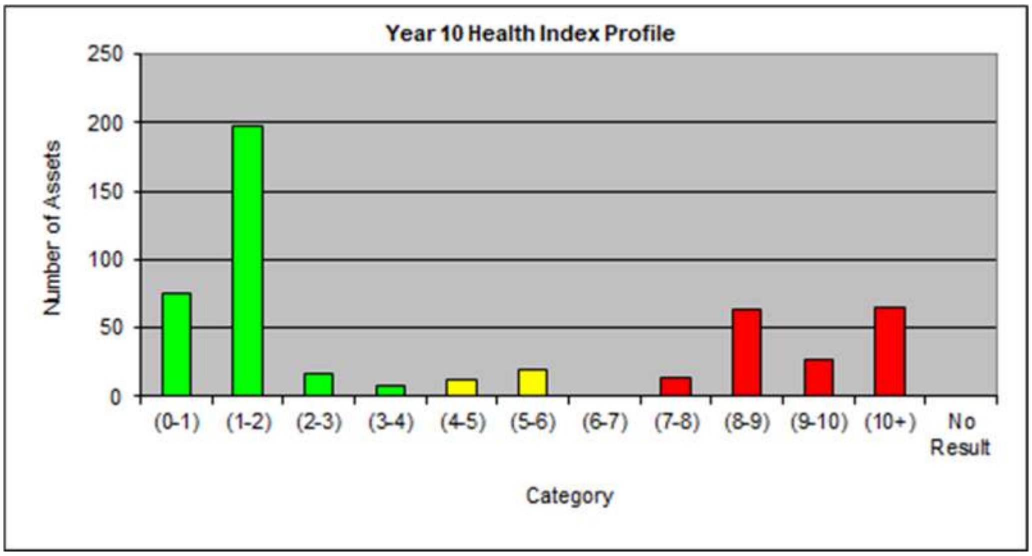
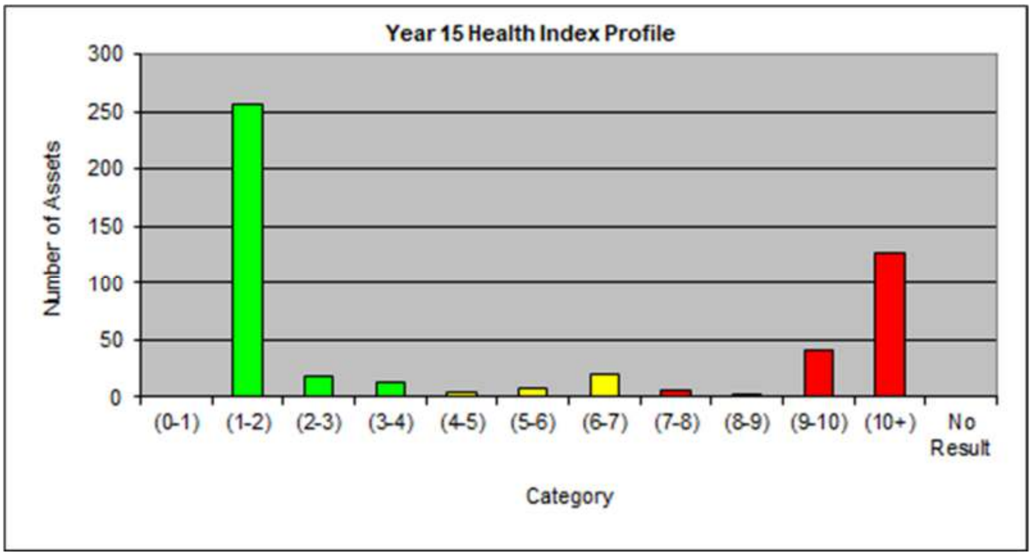
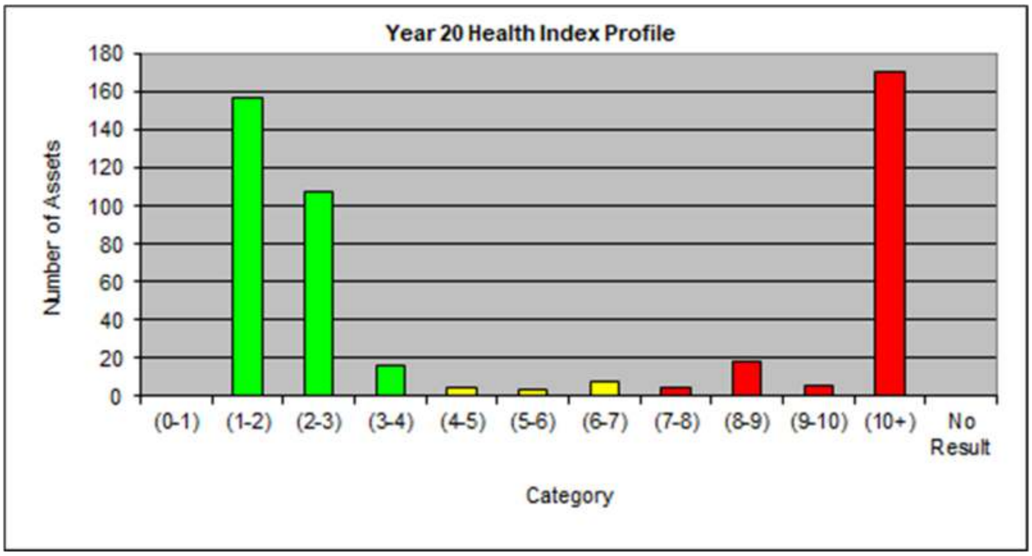


Figure 4–14: Year 15 Health Indices



Total risk for all failure scenarios at Year 15 is calculated to be $24.76M.

Figure 4–15: Year 20 Health Indices



Total risk for all failure scenarios at Year 20 is calculated to be $35.58M.

These results indicate that replacement of these circuit breakers in the coming years should be undertaken in order to manage the risks associated with the number of circuit breakers in poor condition on the network.

Further scenario analysis will be undertaken to determine optimal replacement schedules however the 22kV circuit breakers identified at FE and FW as being in poor condition at Year 0 will take priority.

4.2.2.5 Existing Controls

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.2.4.2., together with initiation of replacement projects for assets determined to in danger of major failure.

JEN has various types of spare breakers and components for 22kV/11kV/6.6kV CBs & buses and one spare for 66kV CBs. Capital projects have been/will be initiated to replace CBs in poor condition and this will address the spares issue. JEN however does not have full complement of spares for every circuit breaker or bus on the network.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and reparability of the failed circuit breakers. Once determined, either components are replaced or whole unit replaced with a spare from stock.

4.2.2.6 Further Information on CBRM

For further information on CBRM please refer to [ELE GU 0005 Condition Based Risk Management (CBRM) Application Guide](). The guide provides a summary of how Jemena utilises CBRM to justify future replacement volumes for distribution and zone substation assets. It outlies the different inputs required and their associated outputs and how these outputs are interpreted.

4.2.3 PERFORMANCE FACTORS

Circuit breakers are expected to provide their rated switching and fault interruption functions when required, for a life time in the order of 50 years. Therefore all factors contributing to maintaining satisfactory **condition** are essential to achieve this goal.

Asset performance for circuit breakers is assessed through a holistic asset management approach that includes routine maintenance, testing, diagnostic condition assessments and CBRM. This work is carried out in line with the various associated plans, policies, strategies and standards.

Asset performance measures for Jemena zone substation circuit breakers are designed to achieve a high level of reliability by undertaking a practical, cost effective program of preventive & corrective maintenance, coupled with planned, economic replacement of circuit breakers before failure; to maintain reliability and quality of supply and mitigate the safety risk to personnel and the public.

Specific circuit breaker performance measures (and condition monitoring) include the following:

- Condition monitoring tests: insulation resistance, partial discharge, dielectric dissipation factor and capacitance.
- On-line, non-disruptive monitoring surveys: measurement of transient earth voltages for metal enclosed switchgear and ultrasonic and UHF detection for air borne partial discharge signals.
- CBRM output in the form of Health Indices for present and prediction into the future without proactive intervention.

4.2.3.1 *Performance requirements and targets*

Specific Asset Management Performance requirements for this asset group include:

- Known condition – completion of nominated condition monitoring tasks at the frequency specified in Section 4.2.6.6 Condition-based monitoring and assessment of the results evidenced by reports available for each asset;
- Preventive maintenance – completion of nominated preventive maintenance tasks specified in Section 4.2.6.4.2 Circuit Breaker Preventive Maintenance & records of tasks completed;
- Planned replacement – identification of end-of-life replacements each year, incorporation in annual works programs and obtaining replacement project approvals; and
- Failure Prevention – avoiding catastrophic (unplanned outage more than 24 hours) circuit breaker failures from occurring within zone substations.- target zero pa

The circuit breaker has a general life expectancy of 50 years for both indoor and outdoor installations. Properly electrically protected, correctly loaded and adequately maintained, a circuit breaker's life expectancy can exceed 50 years. Of the total number of circuit breakers in service across Jemena Electricity Network, 21% are in the 41 – 50 year age range. 16% of the population is over 50 years old.

Factors affecting this life expectancy include:

- Condition of the insulation system of its interruption system;
- HV bushings;
- Build quality; and
- Installation location, i.e. indoor or outdoor (those installed outdoor are more susceptible to vermin and moisture ingress, accumulation of pollution and degradation due to sun light).

4.2.3.2 Condition Assessment

A number of factors are assessed to determine if individual circuit breakers have a high probability that the unit will continue to reliably perform its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and analysis of actual performance are examined. Outputs from the CBRM model are used to provide a comprehensive assessment of CB/switchgear condition.

CBRM outputs in the form of Health Indices shown in Section 4.2.2.3 above provide a visual demonstration the condition of the population of circuit breakers now and into the future if no corrective measures are taken.

Circuit breaker issues have been identified at a number of zone substations that include Airport West (AW), Broadmeadows (BD), Braybrook (BY), Coburg North (CN), Coburg South (CS), East Preston (EP), Footscray East (FE), Footscray West (FW), North Heidelberg (NH), Sunbury (SBY) and Tottenham (TH). Refer to below for more details.

- The Email 345GC 22kV circuit breakers have had contact pull rod failures at a few sites. A project was initiated to replace the pull rods in all cap bank CBs proactively.
- The HBS24 circuit breakers installed at Sub ST in 1985 were found to leak SF6 gas. Feeder ST24 CB was refurbished in 2005 after 20 years of service. Manufacturers of SF6 CB's generally specify that seal replacement is necessary after about 25 years of service, due to the hardening of rubber seals. Although CB gas levels are locally monitored, seal replacement, major overhaul of interrupter due to fault current interruption and mechanism overhaul is inevitable. A program of work has been prepared and budgeted that prioritizes the refurbishment of the ST CB's. Work includes an assessment of contact wear, 'O' ring condition and filtering/dry-out of gas due to by-product formation. No1 & 2 busses plus the spare CB have been completed.
- ABB SACE HA1 22kV circuit breakers on the No.3 22kV bus at zone substation ST have been replaced with ABB VD4 vacuum breakers. The CBs reached their auto points limits and were found with poor quality SF6 in the interruption chambers and excessive mechanical wear of internal components.
- Metro Vickers SB14 22kV switchboard busses installed at FE and FW zone substations are showing signs of age related deterioration. During recent condition monitoring tests they exhibited partial discharge which is a sign of degraded insulation. These CBs are over 70 years old and are planned for replacement during the 2016-20 price review period.
- Following the failure of the 2-3 66kV bus-tie CB at ZSS FE in 2012 and subsequent repair of the KTY-BY 66kV & 1-2 66kV bus-tie CB at BY zone substation, timing checks of all 66/22/11/6.6kV SF6 and Vacuum CBs are recommended. A new timing test set has been

procured and timing checks are being progressively introduced for all 66kV, 22kV, 11kV and 6.6kV SF6,vacuum and oil circuit breakers.

The following provides specific information about circuit breakers issues, as well as general information about other potential and related issues.

Email 345GC 22kV CB’s

The 22kV Email 345GC circuit breaker is an outdoor CB located within various zone substations. These CB’s have been undergoing a bushing refurbishment program, due to a history of compound leaks from the bushings. The bushing refurbishment program is in response to a known defect. This refurbishment program is designed to prevent bushing failure. There have also been minor defects associated with the CB mechanism, particularly with capacitor bank CB’s. This issue has been managed successfully. There have been a small number of failures of the main contact pull rod. The maintenance schedule has been modified to remove the class 2 overhaul at 12 years and implement a class 2 overhaul at 6 years to identify any fractured pull rods. Generally this failure mode is associated with capacitor bank switching and the associated onerous operating duty. It is also suspected that the leaking dashpots might be a contributing factor to the failure of the pull rods. A project to replace the existing Permali wood pull rods in all 345GC cap bank CBs with fibre glass pull rods has been completed. This was following the failure of the existing Permali pull rods in a number of 345GC cap bank CB across JEN. During the pull rod replacement project it was further identified that the pull rod guides were worn and unserviceable. When a defective pull rod is identified in any other breaker, pull rods on all three phases will be replaced with fibre glass pull rods and the dashpot serviced. Evidence is emerging to indicate that new failure modes are emerging as the asset is continuing to age beyond the expected serviceable life. Failure of some existing components can be mitigated by engineering new components but this process is costly and this does not mitigate the age or age related failure of other components within the CB.

In September 2015 BD3 22kV FDR CB failed to open when a command was issued from JEN’s control room. Upon investigation it was identified that the trip latch assembly presented with a build-up of sticky/tacky residue. The residue was a consequence of applying/spraying lubricant to the mechanism without cleaning the existing lubricant. Consequently the trigger and rollers were not moving freely. Once cleaned the trip latch assembly moved freely. The CB mechanism was cleaned thoroughly and lubricated with Shell Tellus Oil and the circuit breaker was subsequently returned to service on the same day. In 2016 two Email 345GC CBs tripped slowly resulting in customer outages and STPIS penalties. A one off mechanism refurbishment program was completed on all Email type 345GC CBs on the network to address the ongoing lubrication and maintenance issues in 2017. This program was supplementary to the current class 1 and 2 (incl. after auto and service ops) maintenance regime facilitated through SAP.

Greater attention is required to cleaning and removal of old dried lubricants and the use of suitable lubricants to last the intervals between maintenance.

345GC CBs at zone subs CN will be considered for replacement with indoor switchgear during the 2021-2025 price review period. The remaining 345GC CBs at zone subs AW and BD will be considered for replacement during the 2026 – 2030 price review period.

ASEA HKEYC 66kV CB’s

JEN presently has 1 HKEYC 66kV circuit breakers in service EP zone substation. ThIS CB’s are no longer supported by the manufacturer and consequently spare components such as porcelain interrupter poles, support stacks and the external drive insulators are no longer available. The 66kV ASEA HKEYC circuit breakers are rated at 800A and can impose limits on 66kV line ratings. The circuit breakers need to be upgraded to 1250A to match modern line ratings. Two of the HKEYC CB’s located at Sub BD have been replaced in 2019 in consideration with the condition issues identified above. The CBs have reached a service life of 52 years. This project was aligned with the relay replacement and control building upgrade project at ZSS BD in 2017. One HKEYC CB located at Sub

ES has been replaced (55 years old) in 2017. Zone substation EP is being retired in 2021 respectively as part of the conversion of the 6.6kV feeders to 22kV. The spare parts made available from the retirement of the HKEYC CB's at BD and ES will provide sufficient spare parts for the CB's at EP until EP is retired.

ASEA HLE 66kV CB's

The 2 HLE 66kV circuit breakers remaining in service at SBY zone substation on JEN were replaced in 2018 as part of a major project at SBY. The circuit breakers were over 50 years old upon their replacement.

AEI LG4C 66kV CB's

JEN presently has 10 LG4C 66kV circuit breakers manufactured from 1966 onwards in service at zone substations CN, CS, EP, FE, FW, HB, NH and NT. These CB's are no longer supported by the manufacturer and consequently spare components such as 66kV bushings, turbulators, solenoids and mechanism components are no longer available. There has been a defect identified in the mechanism of these CB's involving the retaining of a shaft by a washer that is peened on the end of the shaft. This has resulted to damage to the mechanism. An inspection of all of these breakers has been undertaken and a plant defect notice issued.

A bushing testing and refurbish program has been completed. It is necessary due to a history of failures experienced over recent years within the Victorian industry. It is recommended that DDF testing is carried out periodically for the bushings and oil levels monitored at regular intervals. PD testing is also a recognized test that should be undertaken at the same time as the DDF testing. Three LG4C CB's at ZSS AW were replaced in 2017. One LG4C CB at ZSS CN will be replaced with the relay replacement project in 2022/23. One LG4C CB at ZSS HB will be replaced with the 3rd transformer project in 2020. One LG4C CB at ZSS FE will be replaced with the 22kV switchboard replacement project in 2019/20.Two LG4C CB's at ZSS FW will be replaced with the 22kV switchboard replacement project in 2020/21. EP is to be shut down in 2021/22 retiring 1 LG4C. The remaining ZSS consist of indoor and outdoor 66kV LG4C CB's which are to remain in-service and be supported by the spares obtained from those retired from service.

Sub EP – English Electric OLX and Email J18 6.6kV CB's

The existing 6.6kV switchboard dates from 1952. Zone substation EP consists of two switch rooms. Switch room A comprises of a mix of Email J18 and English Electric OLX circuit breakers while switch room B comprises entirely of Email J18 circuit breakers. There is an extensive history of plant defects for this type of switchgear, including instances of failure resulting in fire damage to the switchboard and damage to the control building at FT (Flemington) Zone Substation (**JEN**) and at substations owned by other Victorian distribution businesses. The English Electric OLX circuit breakers in particular have had numerous mechanical failures of differing modalities.

Condition monitoring tests have been/are periodically conducted on the EP switchgear. Current DLA testing regime is set to annually on the switchgear at EP, along with the annual condition monitoring testing. DLA testing conducted on the switchgear at EP in 2012, 2017 and annually in subsequent years has identified that the insulation properties of the 6.6kV switchboard have deteriorated since initial testing in 2012 and are well outside of acceptable limits. All circuit breakers installed at Zone Substation EP are regarded as severely degraded and have been in this state since at least 2012.

Bushing replacements were undertaken at EP Zone Substation, with spares taken from P Zone Substation and Pascoe Vale (PV) Zone Substation, to replace 6.6 kV CB bushings showing a high level of insulation degradation. There are currently no spares available for replacement of faulty bushings or bushings with high Dielectric Dissipation Factor (DDF) readings at EP Zone Substation. The bushing construction is resin bonded paper with the majority of the bushing length exposed to air. Once there is moisture ingress the bushings cannot be repaired. Bushings with high DDF readings indicate current leakage to earth due to moisture ingress in the insulating medium, which then leads to thermal runaway, and can cause catastrophic insulation failure and fire. In the event of a circuit breaker bushing failure at EP there are no spares available to reinstate the circuit breaker or rebuild the bus work. All feeder CBs at EP are annually tested to monitor their degradation. These measures will need to be put in place to ensure a safe and reliable operation of the EP switchboard until it is retired in 2021.

Sub FT – Email J18 and J22 11kV CB's

The existing J18 and J22 switchboard at Zone Sub FT was replaced with new ABB VD4 switchgear in 2018.

Sub SBY – AEI JB424 and Reyrolle OMT 22kV CB's

SBY 33 CB (AEI type JB424) and the No.1 capacitor bank CB (Reyrolle type OMT) were the only examples of these CB's installed on the JEN network. These CBs were no longer supported by the manufacturer and were replaced as part of SBY zone sub rebuild project in 2019.

Sprecher & Schuh HPTW306 22kV CB's

These are minimum oil circuit breakers and are installed at Sub NH, CS, FW and FE. Recently oil leaks have been found on these CB's that could lead to CB failure. The construction of these CB's and their deployment means that oil levels in the CB's can only be monitored when the CB is racked out of the service position. Being minimum oil breakers the total oil volumes held in each CB pole are small. The loss of one litre of oil can result in catastrophic failure. It has been found that the CB's are leaking as a family from "O" ring seals on the drive shafts. A program was initiated for the urgent monitoring of the oil levels in all of these CB's and the replacement of all seals. As of 2013 all of the CBs on JEN have had their seals replaced. The maintenance plans for the CB's have been reviewed.

Sprecher & Schuh HPTW306 22kV buses

In 2016 partial discharge (PD) was detected on switchboards at NH and CS during routine PD testing. An intrusive inspection was carried out subsequently and it was identified that there was visible PD damage on 22kV busbars and standoff insulators. The switchboards had non-OEM modifications made to them at the time of installation. These modifications included PVC conduit covers over bus bars to increase BIL and the addition of plastic barrier boards to shield LV CT from the HV busbar connections. The cause of PD on stand-off insulators can be attributed to there being no air gap between the PVC conduit covers and the solid insulation, especially around exposed copper busbar conductors. In the absence of design documentation, detailing the extent of non-OEM medications of the switchboards, the options to rectify the defects are limited. The PD damage at both CS and NH has been cleaned up and the switchboard reinstated. The renewal of the HV insulation of the 22kV buses at both zone sub CS and NH are being investigated by TEXOnsite to mitigate the PD issues going forward. Periodic monitoring on these switchboards has been scheduled in SAP.

Switchboard replacement at zone sub CS will be considered for replacement during the 2021-2025 price review period.

SCHNEIDER AD4/SF-1

Arc fault explosion barriers for the No.1 & No. 2 22kV buses at BY are shared and there is no physical separation between the two. There were concerns that any fault in the No.1 22kV bus, CB's or CT chambers might vent into the No.2 22kV bus arc chamber and vice versa. Discussions have been held with Schneider and they have demonstrated and assured that that this will not have any impact on the safety on the personnel working on any one section of the bus while the other one is still alive. A written statement of fact has been obtained from Schneider. A risk assessment has been conducted by asset strategy involving all the relevant stakeholders. Work practices will prepare relevant work instructions to ensure all precautions are undertaken when working on the bus and cable chambers for the 22kV switchboard.

The operation of the bus shutters require access procedures to be developed as the mechanism needs to be disconnected for independent operation. Asset Management, Services & Projects and Work Practices are working in conjunction to quantify the risks and prepare relevant work instructions.

Metro Vickers SB14 CBs – Sub FE & FW

Metropolitan Vickers type SB14 switchgear installed at zone subs FE and FW is estimated to be over 70 years old and is unique to Jemena. No other Australian Electricity Business has this switchgear installed. The condition of this switchgear has degraded to a point where employee safety, reliability and security of customer supply will be affected.

In March 2013 the field crew advised that the CBs at FW were leaking oil from either the bus or the feeder isolator compartment. Subsequently, repairs were undertaken in April this year and while the oil leaks have slowed they haven't completely stopped. The CBs will be continually monitored until their replacement.

Condition monitoring tests conducted on the indoor 22kV buses at FW indicates that Partial Discharge (PD) is present above service voltage. This indicates that insulation degradation has occurred. The same switchgear at FE is showing signs of insulation failure. The Condition monitoring tests conducted on the indoor 22kV buses at zone substation FW indicates that Partial Discharge (PD) may be present during normal operating conditions. The damage due to PD cannot be stopped or reversed. Over voltage excursions due to lightning strikes on the network or switching surges can accelerate the insulation degradation further. This will increase the level of PD. The presence of PD will continue to degrade the insulation which will ultimately cause the insulation to fail catastrophically.

This switchgear at FE zone substation is planned for replacement in 2019/20 and FW in 2020/21.

Crompton Greaves – 30-SFGP-25A 22kV CBs

There have been ongoing issues with these CBs installed at ZSS AW, CN, SBY & YVE. Gas leaks were found in one CB at SBY and one CB at YTS; both of these CBs had all three poles replaced with refurbished poles. In March 2014, while doing corrective maintenance on the AW No.4 22kV transformer CB the shock absorber was found to have been dislodged. Further investigation found a gas leak from one of the poles of the CB. All three poles were replaced with refurbished poles and the CB was put back in service.

During 2019 at ZSS AW, the No.4 transformer 22kV CB red phase pole failed to close due to an internal defect and dashpot failure following a subtransmission feeder fault. The CB poles were rebuilt using the retired spares from ZSS SBY.

YVE No. 4 transformer 22 kV CB has had a long history of SF6 gas leaks and is being monitored. The refurbishment of the CB was unsuccessful and the CB continues to leak gas at an increased frequency. This CB has been topped up with gas 4 times in 2019.

With a series of ongoing defects associated with this type of CB, a project will be prepared to replace the AW No.4 transformer 22kV CB and YVE No. 4 transformer 22 kV CB.

In June 2013 the SBY14 feeder CB had a mechanism failure when it was slow to open on a feeder fault. It was discovered that an incorrect specification lubricant was being used on the mechanism of these CBs. A plant bulletin was sent out subsequently, highlighting the problem and recommending the correct lubricant. These CBs were replaced with indoor switchgear at SBY as part of the SBY rebuild project in 2018.

Sump Pump Fail Alarms – Sub FF & Sub NT

Sump pumps are installed in pits under the metal clad switchgear to remove any water that leaks through the cable conduits. These conduits are difficult to seal and therefore water entry into the cable pits can impact on the reliability of the switchgear. The sump pumps are inspected annually for functional operation; however in the event that one of these pumps fails there is no alarm to indicate their failure. A good asset management practice is to install a water level alarm (sump pump fail alarm) to detect abnormally high water level. There is no room on the existing alarm panel at both Sub FF and Sub NT for the implementation of a new sump pump alarm. A new alarm panel or local alarm light on the wall is needed to connect the remote alarm.

Alstom S1-72.5 F1 66kV

Following the failure of the 2-3 66kV bus tie CB at ZSS FE in 2012 timing checks of all 66/22/11/6.6kV SF6 and Vacuum CBs are recommended. A suitable timing test set has been purchased by Services & Projects, Asset Management to support the documentation and implementation of its use.

A similar problem was identified with the KTS-BY 66kV CB and the 1-2 66kV bus tie CB at ZSS BY The CBs were investigated in June 2014 and repaired in November 2014.

Siemens 3AF 22kV CBs – Sub TH

In 2015 partial discharge (PD) was detected on the switchboard at TH during routine PD testing. An intrusive inspection was carried out subsequently and it was identified that there was visible PD damage on No.1 22kV bus; the PD damage was identified across the 22kV bus side fixed isolating contacts and across all circuit breaker isolating contacts.

The metallic fasteners (i.e. bolts, washers and nuts) used to secure the shutter mechanisms to the fibreglass barrier boards are the cause of the PD. The metallic fasteners are not connected to either a live part or ground and are therefore floating. Siemens recommended replacing the metallic fasteners (i.e. bolts, washers and nuts) with an isolating material (i.e. Nylon type 66 materials). Fully operational anti condensation heaters are absolutely critical to prevent PD tracking on this type of switchgear

The PD damage has been rectified and the metal fasteners have been replaced with nylon.

ABB VD4 11kV and 22kV CBs – Sub BMS, ES, HB, PV and TMA

In June 2015 HB32 11kV FDR CB failed to reclose after tripping on a phase-to-phase fault in the JEN distribution system. Three unsuccessful attempts were made by JEN network control to remotely close the HB32 FDR CB. An operator subsequently attended site and racked the CB out and then racked it back in; the CB was then successfully closed. Investigations into this issue revealed that the inherent design of the VD4 CBs is such that there is small tolerance, approx. 10deg, for where the racking mechanism will be in the service position. A plant bulletin, with a directive on how to mitigate against this issue, has been disseminated to the field crew to make them aware of this issue.

Circuit Breaker Bushing Replacements

Prior to installing any replacement circuit breaker bushings, electrical tests (DDF, PD, IR) will be undertaken to confirm their serviceability.

Bushing storage: It is important to cover the bushing stem with an oil filled tube for storage. This needs to be done quickly to avoid moisture ingress. A new hot room has been installed and is now operational at the Tullamarine Depot for the optimal storage of bushings.

Other Issues

Augmentation of the transmission system by SP AusNet has resulted in increasing fault levels at zone substations. The interrupting capability of CB’s has to be monitored in the light of these increasing fault levels to ensure that the interrupting capability of the CB’s is adequate.

4.2.4 Utilisation

Circuit breakers installed across JEN zone substations are power switching devices to selectively control the energisation of electricity distribution equipment and are highly utilized assets. Circuit breakers play a paramount role in the safe and reliable operation of the electrical distribution network as they are used to rapidly disconnect network faults and provide controlled isolation of sections of the distribution network. The safe and reliable operation of the circuit breaker fleet is vital to network operation as they play an essential role in limiting the risks posed to the public, personnel and equipment. The consequence of an in-service failure varies from supply interruptions, environmental damage, fire start and related safety issues to wide ranging supply interruption to a large portions of the network.

All CBs must be operated within their normal current rating and also within their fault interrupting and fault current carrying capacity. Loading and fault current levels due to changes in the upstream transmission systems are monitored to check CBs/switchgear is capable of operating at the required levels.

4.2.5 Control Effectiveness

Controls employed are identified in Section 4.2.4.2. and condition based replacements completed are listed in Section 4.2.4.3 These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table.

Table 4-25: Effectiveness of Existing Controls

Risk Category	Cause/incident	Controls	Incidents in past 5 years
Health, Safety & environment	Circuit breaker or bushing explosive rupture failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed	Nil
Regulatory & Compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Slow trip of 345GC 22 kV CB caused loss of half of all customers at AW. Slow trip of 345GC at BD – no customer interruption.

4.2.6 Life cycle management

Specific aspects of the asset strategy involve information about:

- asset lifecycle management options;
- asset creation (including asset acquisition and asset spares);
- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring); and
- asset replacement and disposal;

4.2.6.1 *Lifecycle management options*

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure. The preferred asset lifecycle management option involves condition monitoring and preventive maintenance, with the aim of achieving at least 50 years of asset life before replacement.

There are 3 feasible lifecycle management options:

- Condition monitoring and preventive maintenance, with condition and risk based replacement. Correctly loaded and adequately maintained, a circuit breaker's life expectancy can exceed 50 years;
- Preventive maintenance with fixed, age-based replacement (irrespective of condition). This option is not considered to be cost-effective, as condition monitoring can be more optimally employed to defer capital replacement based on risk assessments; and
- Corrective maintenance and run-to-failure replacement. This is not a realistic option due to the criticality of the assets (circuit breakers), the long lead-time for replacement, the significant cost of carrying several system spares plus health & safety risks and continuity of supply to customers risk

4.2.6.2 *Lifecycle management Scenarios*

The current asset strategy, involving adequate monitoring and maintenance together with condition and risk based replacement, is the best option to achieve life expectancies in excess of 50 years.

4.2.6.3 Asset Creation

Circuit breakers assets are effectively created via acquisition, upgrades or replacement. The new 11/22kV CBs shall be vacuum and new 66kV CBs shall be SF6. This requirement is in line with current modern standards and good industry practice.

Circuit breakers and switchgear are typically purchased under period contracts in alignment with the primary plant manual and specification requirements. Incorporation of the elements of this document, particularly opportunities for future improvements, will determine requirements of plant specification.

4.2.6.4 Asset Operation and Maintenance

This section provides information about the asset maintenance program, including inspection and testing, preventive maintenance, and reactive and corrective maintenance.

4.2.6.4.1 Circuit Breaker Inspection and Testing

Operators visually inspect circuit breakers when visiting substations. Also engineers conduct whole of substation audits at least annually identifying any obvious defects.

Thermographic surveys are conducted annually and cover all zone substation electrical assets (Refer to the JEN Line Inspection Manual).

Annual Kelman (time-travel) testing of all 66kV, 22kV, 11kV and 6.6kV oil CBs has been scheduled in SAP.

On-line Transient Earth Voltage (TEV) and Partial Discharge (PD) are conducted annually on all metal enclosed switchboard cubicles. The switchboards at TH, CS & NH are tested every 6 months

Off line more extensive DLA and PD tests are conducted on all switchboard buses and CB bushings every 5 years.

The bushings of 66 kV LG4C CBs also have DLA & PD tests applied every 5 years.

The bushings of 22kV 345GC CBs are planned to have DLA tests applied in 2019.

4.2.6.4.2 Circuit Breaker Preventive Maintenance

(a) Basic Philosophy

The basic philosophy is that CBs should only be maintained when they need to be. This is a simple philosophy, but not easily to achieve in practice. Preventive maintenance should only be performed when the condition of the CB indicates that maintenance is required.

To assess the condition of any particular CB and determine when maintenance is necessary, 3 condition indicators are used. Fault interruption duty, the number of switching operations performed and elapsed time are used to determine when maintenance should be carried out. In addition new techniques are being tried to give improved condition data.

To determine mechanism operating reliability a trip/close coil monitor (Kelman) instrument is being used to record current versus time information. From this information slow operation can be detected. In the future, it is planned to capture the first operation at a scheduled maintenance and for CBs with some history of problems recordings at intervals between maintenance.

In addition a functional check is to be performed on each circuit breaker annually (open – close operation), if the CB has not been operated during this period. Many circuit breakers are not called on to operate for extended periods and this functional test will check the control systems from the control room to the circuit breaker and in addition exercises the lubrication on the circuit breaker mechanism and thus reduces the likelihood of slow or sticking operation.

(b) Guideline Documents

This philosophy is documented in two documents as follows:

- Tabulation of Zone Substation circuit breakers with operations limits and default time periods to initiate routine maintenance; Doc No. ELE AM GU 0012 (Draft); and
- Circuit breaker auto point system (after automatic protection operations) classification for maintenance; Doc No. ELE AM GU 0013 (Draft)

These documents describe the criteria for determining when maintenance should be carried out on CB interrupters after a certain fault interrupting duty.

The detail of circuit breaker routine maintenance is documented within the Guidance documents above, the Reliability Centred Maintenance (RCM) final implementation report and the SAP PM. These documents describe the criteria for CB operating mechanism maintenance intervals and the maximum time interval between interrupter maintenance.

(c) Scope of Documents

These guidance documents were updated to reflect an improved CB tabulation for the allocation of auto points. It covers a method of determining and recording the fault interruption duty carried out by any particular CB by allocating a number of points to each CB after a fault operation. The number of points is determined from the number of full rated faults the CB is capable of interrupting; the fault level at the station; the location of the fault, ie. Whether at the station or a known distance from the station and whether the fault is three phase or a phase to earth fault.

The sum of the number of allowable faults at rated duty is equated to 100 points. When the accumulated number of points for a particular CB reaches 100 points, the CB contacts and arc control devices, etc. require maintenance.

SAP PM, records the number of normal load switching operations allowed for each CB type

Time based maintenance is essential to address degradation of mechanism lubricants and seals. The requirement for time based maintenance is documented in the RCM implementation report and the SAP PM.

(d) Classes of Maintenance

For certain types and makes of circuit breakers experience has shown that it is necessary to service operating mechanisms and auxiliaries more frequently than the primary contact systems and that other components such as seals only require replacement at infrequent intervals. Experience locally and overseas has also shown that most failures occur in the mechanisms and auxiliaries. Therefore a greater emphasis must be placed on servicing these components.

For these reasons a substantial number of circuit breakers at present have two Classes of service in the maintenance program.

Class 1 Service — a service of the mechanism (without dismantling) and auxiliaries and the performance of diagnostic testing. The results of the diagnostic tests will indicate whether the scope of work at the service will need to be increased.

Class 2 Service — includes all the Class 1 work plus interrupter servicing or replacement and limited dismantling for lubrication of the mechanism as detailed in the relevant Standard Maintenance Instruction. The majority of the bulk and minimum oil (old generation type) circuit breakers have Class 1 & Class 2 services performed at more frequent intervals than vacuum and SF6 CBs (primarily known as low maintenance types).

Vacuum interrupting chambers do not require any maintenance on the contacts and are sealed for life. The service duty on the vacuum interrupters will be assessed to determine their need for replacement. SF6 interrupters however, can be serviced. Reconditioning of SF6 breakers is recommended after 5000 to 10000 operations by the manufacturer and requires dismantling of the sealed interrupting chamber. This has not been included in the scope of the documents above. The reconditioning would require specifically trained personnel, manufacturer's expertise and spare parts to carry out the work. Moreover a circuit breaker may not reach the 5000 – 10000 CO operations limit in its life time to warrant any reconditioning.

The following table lists the maintenance triggers for metalclad buses and circuit breakers as implemented in the SAP PM MMS.

Table 4-26: Circuit Breaker Maintenance Intervals

Asset	Maintenance Strategy	Maintenance package
Metalclad buses – air insulated	Time based	≤ 6 years for new buses initially & known bus defects
Metalclad buses – air insulated	Time based	≤ 8 years
Metalclad, Feeder & Cap OCB's	Time and Condition	8Y Class 2, After Auto and/or Service Operations
Metalclad, Transf & B/T OCB's	Time and Condition	6Y Class 2, After Auto
Metalclad, Transf & B/T VCB's	Time and Condition	6Y Class 1, After Auto
Metalclad, Feeder & Cap VCB's	Time and Condition	8Y Class 1, After Auto and/or Service Operations
Metalclad, Transf & B/T SF6 CB's	Time and Condition	6Y Class 1, After Auto
Metalclad, Feeder & Cap SF6 CB's	Time and Condition	8Y, After Auto and/or Service Operations
Outdoor 22kV OCB's	Time and Condition	6Y Class 2, generally 345GC CB's After Auto and/or Service Operations
Outdoor 22kV VCB's	Time and Condition	6Y Class 1 After Auto and/or Service Operations

Asset	Maintenance Strategy	Maintenance package
Outdoor 66kV OCB's (HKEYC & HLE)	Time and Condition	6Y Class 2, After Auto
Outdoor 66kV OCB's (LG4C & HLC)	Time and Condition	6Y Class 1, 12Y Class 2, After Auto
Outdoor 66kV SF6 CB's	Time and Condition	6Y Class 1 After Auto and/or Service Operations
Metalclad bus condition testing	Time	5 years
LG4C bushing tests	Time	5 years
TEV/PD tests on ZSS	Time	1 year

The maintenance intervals specified in the above documents will be continually reviewed based on feedback of condition found during maintenance. This continual evolution and refinement is intended to optimise maintenance intervals and practices. This relies on the use of a well maintained and managed maintenance management system.

A new development to be assessed is the progressive introduction of fault monitors that measure and accumulate actual fault currents interrupted by CBs. Modern day protection relays have in-built functionality to record the fault current interrupted by the circuit breaker. An initiative currently being considered is to fine-tune the timing of maintenance of CBs after fault interruption duty. These features, now readily available in multi-function protection relays, can be integrated into our plan for greater remote control and monitoring, enabling real time data to be brought back to a central Control Centre.

4.2.6.5 *Circuit Breaker Reactive and Corrective Maintenance*

Repair of faults in CBs will be carried out as they occur. Any defects that are discovered during inspections or routine preventive maintenance shall be scheduled for repair at a ~~an~~ opportunistic time appropriate to the severity of the defect. Reactive and corrective maintenance is carried out when faults occur or after inspection has identified faults (or both).

4.2.6.5.1 Fault response and repair strategy

The fault response and repair strategy for this asset class involves site attendance by Jemena's fault response crew within the hour. Repairs of the failed equipment depend on a number of factors, such as:

- type and extent of damage;
- complexity of repairs; and
- availability of spare components.

4.2.6.6 *Condition-based monitoring*

For all indoor switchboards, a comprehensive set of condition monitoring tests (Insulation Resistance, Partial Discharge, Dielectric Dissipation Factor and Capacitance) shall be conducted on the fixed cubicle buses. These tests are to be conducted at 5 yearly intervals unless condition issues are identified as a result of testing. In this case, tests shall be conducted at more frequent intervals.

In addition to these tests on-line non-disruptive monitoring surveys of circuit breaker and switchboard condition are to be undertaken on an annual basis. These surveys shall include the measurement of Transient Earth Voltages (**TEV**) and Partial Discharge (PD) within metal enclosed switchgear in service, ultrasonic detection, and UHF detection of air borne partial discharge signals. Any switchgear that shows high readings shall then be subjected to the more comprehensive test described above. These tests shall be applied to all indoor and outdoor switchgear where appropriate irrespective of age.

4.2.6.7 Circuit Breaker Future Improvements

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

- DLA testing of all Email 345GC 22kV CB bushings;
- SF6 and Vacuum CB timing checks using the new Doble TDR test set; and
- Online condition monitoring for critical circuit breakers and switchboards.

As indoor switchboard failure and possible fire are potential catastrophic failure events; a relocatable switchroom fitted with HV switchboard and protection should be considered.

The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information on circuit breakers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

4.2.6.8 Asset Replacement/Disposal

Replacement of zone substation circuit breakers is initiated when all cost effective maintenance and life extension options have been considered and condition monitoring has indicated that the circuit breaker has an unacceptable risk of failing electrically, thermally or mechanically and the deterioration trend cannot be halted or reversed.

While planned circuit breaker replacement is determined and prioritised based on ongoing test results, budget constraints and other network requirements (such as capacity constraints) is also considered. Whilst individual lifecycle management plans determine anticipated expenditure on a specific asset class, various asset classes will compete for the available funding.

A project prioritisation process is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how Jemena prioritises and optimises its investments.

More broadly, Jemena looks at the specific asset drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-27: Circuit Breaker Specific Drivers provides an overview of the circuit breaker specific drivers of the proposed replacement volumes and expenditure.

Table 4-27: Circuit Breaker Specific Drivers

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment	Circuit breakers experiencing tripping defects (slow operation, mal-operation etc.)	Failure to fulfil critical network functions, that could cause significant numbers of customers off supply (i.e. Zone substation protection tripping)

Driver	Risk/Opportunity Description	Consequence
		Failure to isolate properly causing safety risks Failure to interrupt fault currents
Asset Integrity	Increased operational duty of some circuit breakers	Will cause mechanical failure of the primary contact drive systems and lead to reduced asset life (particularly caused in the case of Zone substation Capacitor bank CB installations that are operated on a daily basis)
Asset Integrity, Health, Safety and Environment, Regulatory compliance	Leaking insulating compound on some CB bushings	Will cause failure if unattended, leading to interruption of supply to customers.
Asset Integrity	Some CB types have been identified as suffering age related deterioration of the insulating systems (related to synthetic resin bonded paper bushings)	Failure may lead to customer supply interruption.
Asset Integrity, Health, Safety and Environment	Increasing fault levels at zone substations needs to be monitored to ensure that the interruption capability of the CBs are adequate	Inadequate CBs causing supply, fault current interruption, safety and other risks.

Historical capital expenditure (2005 to 2018)

Table 4-28 lists information about historical CAPEX for the period 2005 to 2018.

Table 4-28: Circuit Breaker Replacement History from 2005 to 2018

Year	Qty.	ZSS	Type	Reason for Replacement
2005	17	NS	GEC K5	Bus pitch leak, spring charged CB mechanism defects.
2006	6	YTS	GE FHK039	Retirement of 6.6kV Distribution voltage.
2007	18	FF	Reyrolle C6T	Pitch filled bus, spring charged CB mechanism defects.
2007	1	P	EE OLX	Converted to vacuum interrupter.
2008	2	SBY/YTS	Crompton Greaves	Replaced seals due to gas leaks.
2009	17	NT	Reyrolle A2T	Pitch filled bus. Aged asset.
2010/11	15	HB	Email J18	Aged asset. Deteriorated condition from test results.
2011/12	14	PV	EE OLX	Aged asset. Deteriorated condition from test results.
2012	2	PV	GEC LG4C	Aged asset. Failure history, deteriorated bushings and mechanism problems.
2012/13	2	YTS	Reyrolle OS10	Aged asset. Part of retirement program.

Year	Qty.	ZSS	Type	Reason for Replacement
2012/13	3	YTS	Reyrolle OS10	Planned Retirement of YTS.
2012/13	19	YTS	WR 345GC	Planned Retirement of YTS.
2012/13	16	ES	Reyrolle LMT	Aged asset. Deteriorated condition from test results.
2014	1	BD	ABB VBF36	Deteriorated condition from test results.
2015	8	ST	SACE HA1	Deteriorated interrupter condition.
2015	1	ES	ASEA HKEYC	Aged asset. Spares required.
2017	3	AW	GEC /MV LG4C	Aged asset. Failure history, deteriorated bushings and mechanism problems.
2017	19	P	EE OLX & 66kV HKEYC	Aged asset. Deteriorated condition. Retired as part of network augmentation project – ZSS P retired & will be redeveloped as PTN).
2018	15	FT	Email J18	Aged asset. Deteriorated condition from test results.
2018/19	10	SBY	AEI JB424 Reyrolle OMT3 CG 30 SFGP HPFC409K HLE	Aged asset. Network augmentation project – costs are part of the ZSS SBY augmentation / upgrade)
2019	2	BD	ASEA HKEYC	Aged asset. Spares required.

Forecast capital expenditure (2019 to 2028) Table **4-29** lists proposed replacements from 2019 to 2028. The CBRM model is utilised to determine the highest priority CBs/switchgear in need of replacement and the table below shows the replacement volume and prioritised based on ongoing test results and network requirements such as capacity constraints.

Table 4-27 shows historically 185 circuit breakers were replaced between 2005 and 2018. Looking forward, a further 38 circuit breakers will be replaced from 2019 to 2021.

In line with the CBRM model (refer table 4-21), the circuit breaker replacement at BD, SBY, FE, FW, EP and HB. Business Cases have been approved for BD and SBY and site construction has commenced. The circuit breaker replacement projects for FE, FW and HB are being prepared.

Table 4-29: Proposed Circuit Breaker Replacements from 2019 to 2028

ZSS	Qty.	Type	Estimated Replacement Timeframe	Reasons for Replacement	Comments
FE	12 1	MV SB14 GEC LG4C	2020/21	Condition/age	Aged asset. Aged asset. Failure history, deteriorated bushings and mechanism problems.

ZSS	Qty.	Type	Estimated Replacement Timeframe	Reasons for Replacement	Comments
FW	18 2	MV SB14 GEC LG4C	2019/20	Condition/age	Aged asset. Aged asset. Failure history, deteriorated bushings and mechanism problems.
HB	1	GEC LG4C	2020/21	Condition/age	Aged asset. Failure history, deteriorated bushings and mechanism problems.
CN	1	GEC LG4C	2022/23	Condition/age	Aged asset. Failure history, deteriorated bushings and mechanism problems.
EP	2 1 13 23	AEI ASEA EE Email	2021	Condition/age	Aged asset. Deteriorated condition.11kV J18 & OLX; 66 kV HKEYC (1) LG4C (2) (Network augmentation project – zone substation EP will be retired and redeveloped as EPN).
CN	1 1 12	AEI Crompton Greaves Email / WR	2022/23	Condition	3 buses (345GC) & building
CS	1 11	AEI Sprecher & Schuh	2024/25	Condition	22 kV switchboard & 66 kV LG4C
AW	2 2 16	AEI Crompton Greaves Email / WR	2026/27	Condition / age / spares	4 buses (345GC) & building
BD	2 18	ASEA Email / WR	2027/28	Condition	4 buses (345GC) & building
NT	1	LG4C	2028/29	Condition/age/ spares	Replace 66kV LG4C CB
NH	1 13	AEI Sprecher & Schuh	2028/29	Condition	22 kV switchboard & 66 kV LG4C

All CBs containing oil are oil sampled as part of the disposal process to determine the level (if any) of PCB contamination so that the insulating liquid can be disposed of appropriately.

CB’s containing SF6 gas are disposed of in accordance with EPA requirements.

Any CBs containing asbestos components are disposed to an authorised asbestos contractor

In some instances where spare parts are not readily available for older CBs, when they are retired or replaced they shall be retained for spare parts. All other retired and decommissioned CBs are sent to scrap.

4.2.7 Information

Jemena's AMS provides a hierarchical approach to understanding the information requirement to achieve Jemena's business objectives at the Asset Class. In summary, the combination of Jemena's Business Plan, the individual Asset Business Strategy (ABS) and Asset Class Strategy (ACS) all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives (Table 4-30). Table **4-31** identifies the current and future information requirements to support the Sub Asset Class critical decisions and their value to the Asset Class. Table 4-32 provides the information initiatives required to provide the future information requirements identified in Table **4-31**. Included within this table is the risk to the Sub Asset Class from not completing the initiative.

All of the information required by the circuit breaker Sub Asset Class is available within Jemena's current business systems.

Table 4-30: Circuit Breaker Business Objectives and Information Requirements

Business Objective	Jemena Information Sources	Externally Sourced Data
Maintain Safety, Availability and Reliability of Circuit Breakers	SAP. DrawBridge. Condition/maintenance reports Daily situation reports (email) stored by JEN Control Room. Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee. Alerts – from DB's and Government Organisations and manufacturers. Manufacturing manuals. AS/IEC standards.

Table 4-31: Circuit Breaker Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Circuit Breaker - Asset Creation	Specifications and tender responses Zone Substation Primary Design Standard New asset project progress reporting. Completion recorded in SAP Asset register in SAP		High: Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of the Circuit Breaker via Inspections, and audits	Asset register SAP, with details of each asset and significant components; • Manufacturer • Type • Equipment description • Construction year • Basic specification	Migrate Condition & Performance reports/data into SAP to improve analysis and decision making. Photograph circuit breaker nameplate and	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	○ Voltage ○ Current • Location: Zone substation name • Address Condition Monitoring Maintenance reports & Test reports Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts SMI's – (Standard maintenance instruction) SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP	attach to SAP equipment. Access all information via electronic tablet in the field.	
Maintain functionality of Circuit Breakers via Preventive Maintenance	Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. Scheduled task description, timing and completion recorded in SAP; SMIs held in Sharepoint, Policies & Forms. Manufacturers maintenance manuals SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP ZSS fault current level calculations - Published annual Distribution Planning Report available on Jemena website Daily situation reports (email) Stored by JEN Control Room, used to determine fault level interrupted by the CB. ZSS Auto Points table	Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. Connectivity required for ZSS protection relay to SAP for CB wear monitoring and to be used for maintenance planning.	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	Details of spare equipment located in SAP OPEX & CAPEX cost reporting recorded in SAP	Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	
Maintain functionality of Circuit Breakers via Condition Monitoring	Condition monitoring tasks, schedule in SAP and results stored in proprietary test equipment data base and SAP. Scheduled task description, timing and completion recorded in SAP. Outputs from condition monitoring analysis.	Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	High: Regulated to maintain supply reliability, safety and quality of supply

Respond to Circuit Breaker defects / faults to restore equipment operationally. Perform corrective maintenance.	Alerted via JEN Control Room or situation report.
	
	Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• basic specification
	    ○ Voltage
	    ○ Current
	• Location: Zone substation name
	• Address
	
	SAP notifications and work orders activities performed and components replaced.
	
	Details of work completed recorded in SAP
	
	Condition Monitoring
	Maintenance reports & Test reports
	
	Performance history:
	• Daily situation reports
	• Investigation reports (ECMS)
	• Plant defect reports.
	
	DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts
	
	Asset failure details and investigation reports.
		Although hard copies of manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in in Drawbridge. Manufactures manuals for older assets may not be available.
		
		Access all information via electronic tablet in the field.
		
		All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.
		
		Update asset data in SAP for missing data.
			High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	Details of spare equipment located in SAP OPEX & Capex cost reporting recorded in SAP		
Circuit Breaker – Condition Based Risk Management (CBRM)	CBRM analysis Health Index Held by Primary Plant Distribution Systems Group		High: Regulated to maintain supply reliability, safety and quality of supply
Circuit Breaker – Rating suitable for load demand	ZSS load forecast in ECMS Published annual Distribution Planning Report available on Jemena website		High: Regulated to maintain supply reliability, safety and quality of supply
Asset Class Strategy Review	Condition data Fault/failure data Maintenance & replacement costs AMS		Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-32: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph circuit breaker nameplate and attach to SAP equipment Connectivity required for ZSS protection relay to SAP for CB wear monitoring and to be used for maintenance planning Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	To improve analysis and decision making. Asset data available from business systems saving on site trips. Utilise CB current interrupted recorded in protection relays to determine when maintenance is necessary	Poor efficiency in accessing asset data and possible risk of maintenance inefficiencies.	Utilise available data from protection relays in lieu of generic fault level calculations and auto points allocation. Asset Data as per RCM and SAP requirements.

4.3 ZONE SUBSTATION DISCONNECTORS AND BUSES

4.3.1 INTRODUCTION

The Disconnectors and Buses Strategy applies to HV disconnectors, isolators, buses and associated equipment installed in zone substations. The term Disconnectors and Buses is referred to throughout this document; it is a generic statement which includes the following equipment:

- Disconnectors (including motor operated disconnectors);
- Isolators;
- Earth switches;
- Bus conductors;
- Flexible connections and connectors;
- Surge arresters;
- Walling bushings; and
- Insulators.

This Sub-Class excludes indoor metal clad switchgear.

4.3.1.1 Asset Specification

Table 4-33 depicts the voltage ratio, the number of high and low tension buses, and, the number of wall bushings installed in the various Zone Substations on the JEN network.

Table 4-33: Bus and wall bushing Information

ZSS	Voltage Ratio (kV)	No. of High Tension Buses	No. of Low Tension Buses	Transfer Bus	No. of Wall Bushings
AW	66/22kV	4	3	Y	N/A
BD	66/22kV	4	3	Y	N/A
BMS	66/22kV	3	2	N	N/A
BY	66/22kV	2	2	Y	N/A
CN	66/22kV	3	3	Y	N/A
COO	66/22kV	2	2	N	N/A
CS	66/22kV	3	2	N	8
EP	66/6.6kV	3	6	N	N/A
EPN	66/22kV	1	1	N/A	N/A
ES	66/11kV	2	2	N	N/A
FE	66/22kV	2	2	Y	N/A
FF	22/6.6kV	Direct line entry	3	Y (on 22kV side)	N/A

ZSS	Voltage Ratio (kV)	No. of High Tension Buses	No. of Low Tension Buses	Transfer Bus	No. of Wall Bushings
FT	66/11kV	3	3	N	12
FW	66/22kV	3	3	Y	N/A
HB	66/11kV	3	3	N	N/A
MAP	66/22kV	2	Melbourne Airport's responsibility	N/A	N/A
NH	66/22kV	3	3	N	12
NS	22/11kV	Direct cable Entry	3	N	N/A
NT	66/22kV	3	3	N	9
P	Station will be rebuilt as PTN in 2019.				
PV	66/11kV	3	3	N	N/A
SBY	66/22kV	7	3	Y	N/A
SHM	66/22kV	2	2	N	N/A
ST	66/22kV	3	3	N	24
TH	66/22kV	3	2	N	N/A
TMA	66/22kV	2	2	N	N/A
YVE	66/22kV	3	4	N	N/A

4.3.1.2 Population and age profile

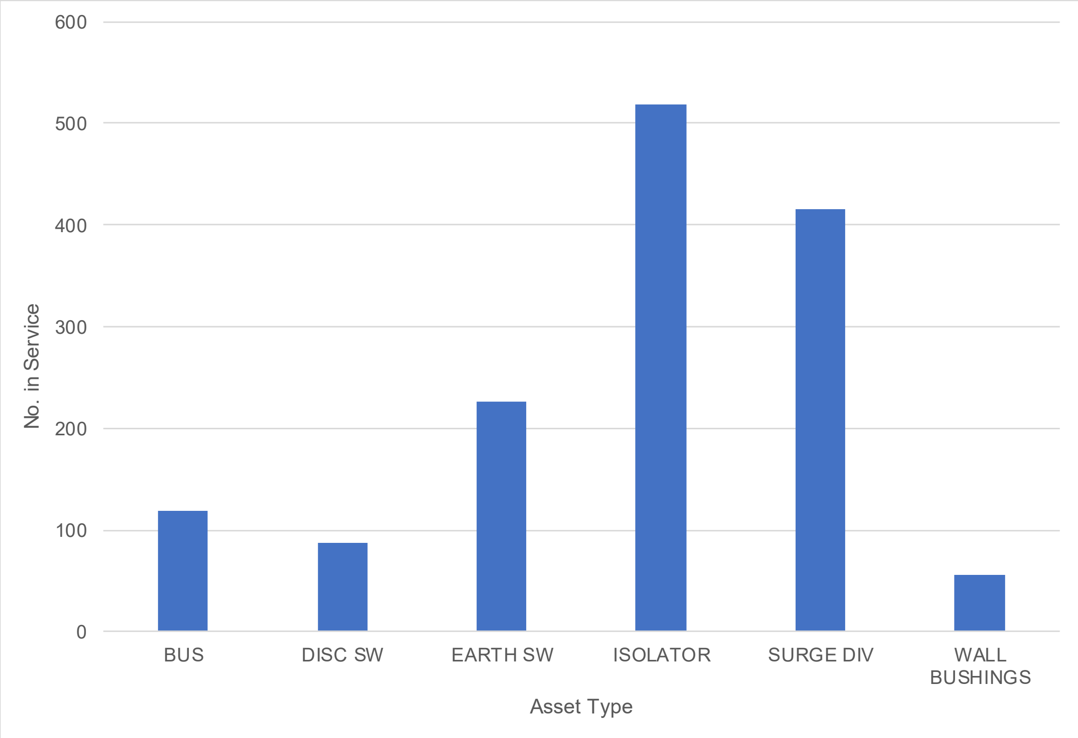
The primary plant population is spread across 26 zone substations and 4 HV customer substations with Jemena assets installed[8].

Flexible connections and connectors are not recorded due to their inherit nature. Insulators are not stated because they are generally associated with the equipment they are connected to (i.e. disconnector, bus, circuit breaker etc.).

Figure 4–16 identifies the population of different types of primary plant equipment (i.e. buses, disconnect switches, earth switches, surge diverters and isolators).

[8] Refer to Appendix K for a list of JEN zone substations and HV customer substations with Jemena assets installed.

Figure 4–16: Asset Population



The average age of disconnectors/isolators, earth switches, buses, surge arresters and wall bushings installed on the JEN network is shown in Figure 4–17. Notably disconnectors/isolators and buses have an average age >35 years and may require more age related maintenance in the coming years.

Figure 4–17: Average Age of Specific Assets

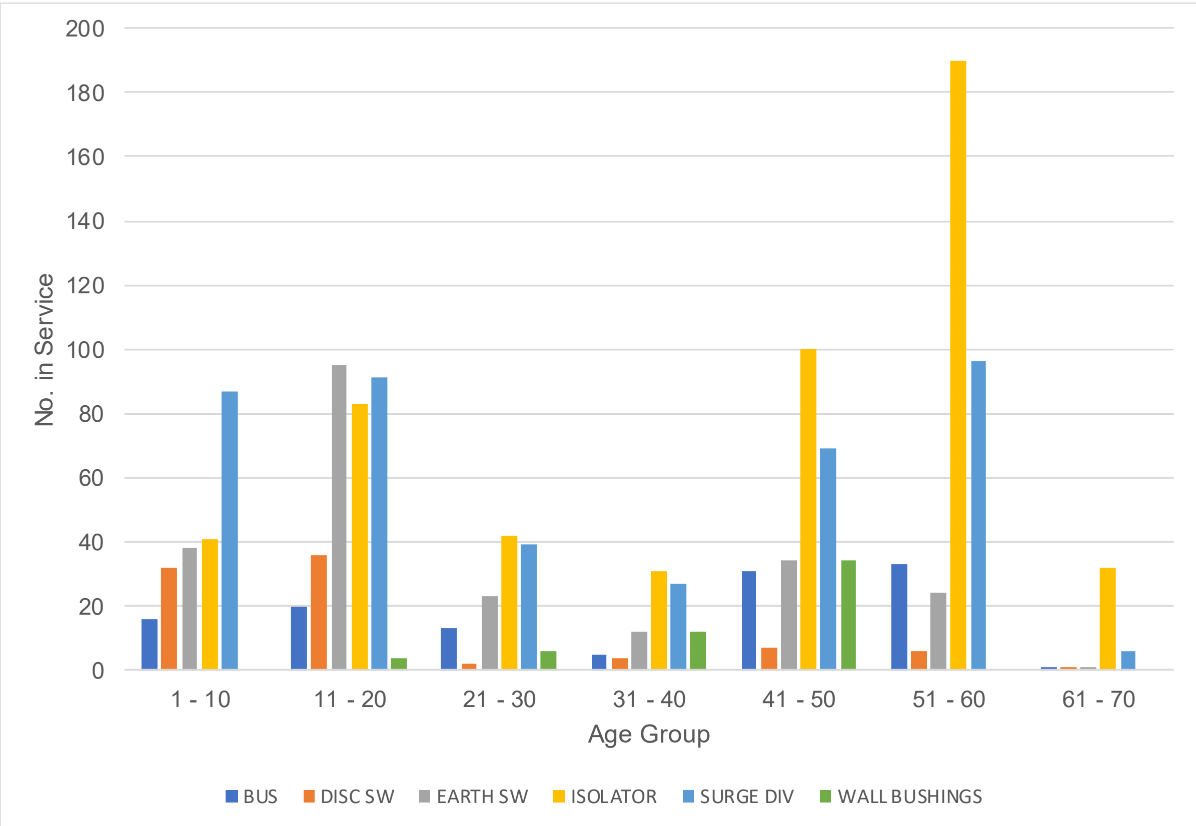
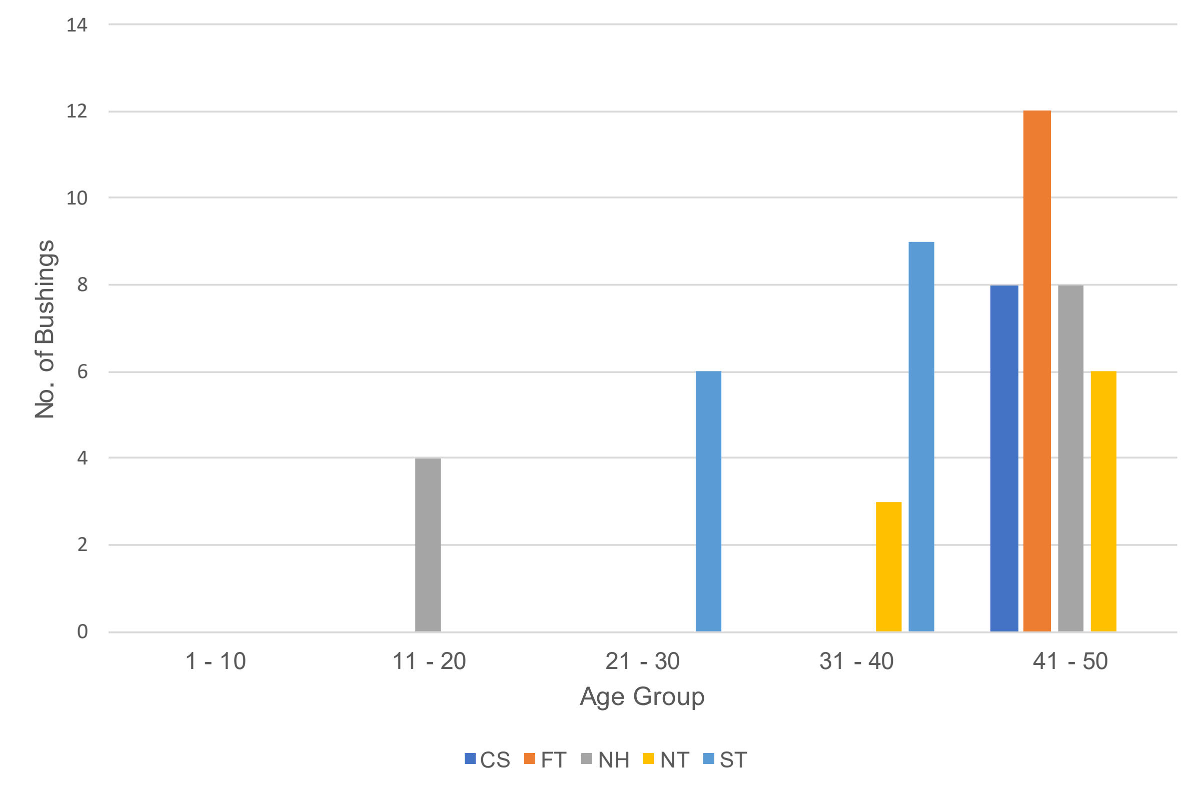


Figure 4–18 shows the age profile of wall bushings in service across the Jemena Electricity Network.

Figure 4–18: Wall Bushing Age Profile



The oldest wall bushings date back to 1970 and are located at FT. The bushings located at CS are a 1976 specification and are therefore 37 years old. 50% of the wall bushings on the JEN network are >30 years old.

Wall bushings are difficult to access and historically haven't been tested on the JEN network. Due to the aging population a testing program has been initiated. The testing program utilises DDF tests to evaluate bushing condition and determine if any replacement strategies are required. Difficulties in accessing wall bushings due to working at heights has slowed the testing program.

4.3.2 RISK

This chapter includes information about Disconnector and Bus risk profiles involving the way that asset class criticality is established, the risks posed by Disconnector and Bus 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 Disconnectors and Buses.

This information specifically involves:

- Asset class criticality score (sub asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Condition Based Risk Management (CBRM) for identifying assets approaching end of life;
- Existing controls;
- Asset Spares;
- Contingency; and

- Future risks (involving other potential risk issues currently being managed).

Buses, disconnectors, isolators and earth switches are generally very reliable and risk of failure is considered to be low. The major risks associated with disconnectors are related to failures due to high resistance connections and insulation breakdown. Failure to maintain a bus, disconnect or earth switch can lead to melting of contacts or connections, arcing and flashover due to insulation degradation and mal-operations of equipment. This can result in total loss of supply to all customers supplied from the zone substation, or equipment failure causing delayed operations.

Traditionally wall bushings have not failed but risk assessments have identified a failure will place a zone substation(s) on single contingency until the sub transmission fault is repaired. Additionally personnel safety is at risk in the event of a failure due to porcelain fragments.

Risks for this asset class and the probability and consequence of these occurring include:

- Regulatory non-conformance (equipment failure), likelihood is rare; consequence additional scrutiny by Regulator is Minor resulting in Low risk;
- Health and safety issues (equipment failure), likelihood is unlikely; consequence person injury is serious resulting in Low risk;
- Environmental issues (equipment failure), likelihood is unlikely; consequence scattered broken components is minor resulting in Low risk;
- Financial Impact (replacement costs), likelihood is unlikely; consequence of few $k is minor resulting in Low risk;
- Operational (loss of supply), likelihood is rare; consequence of bus outage for several days is major resulting in Moderate risk; and
- Reputational risk, likelihood is rare; consequence of sporadic media/public attention is serious resulting in Low risk.

Specific Disconnector risks include:

Table 4-34: Disconnector drivers and risks

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Health, Safety and Environment	Disconnectors not closing/opening circuit properly	Failure to appropriately isolate plant within stations This presents a high risk to employee safety
Asset Integrity, Health, Safety and Environment	High resistance connections in some families of older bus systems	Failure to appropriately isolate plant within stations This presents a high risk to employee safety
Asset Integrity, Health, Safety and Environment	Issue with latching mechanism in some disconnects, that also have a history of failure	Will cause it to open during heavy loads/while carrying fault current This presents a high risk to employee safety

Emerging risks for this asset class include:

- Ageing population;
- Deteriorating insulation condition of bus insulators disconnector and earth switch insulators, surge arrestor housings;
- Deterioration of disconnector and earth switch operating mechanisms and linkages and contacts;

- Expenditure prioritisation restricting timely replacements;
- Damage due to birds and animals and possibly vandalism;
- Non-availability of components for old disconnectors and earth switches; and
- Moisture ingress and deterioration of non-linear resistor blocks in surge arresters

4.3.2.1 Criticality

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub asset class level by following the Asset Criticality Assessment Procedure (JEM AM PR 0016). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of Jemena'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 disconnector and buses has an asset criticality score of AC4 (High) due operational and health and safety consequences associated with failures.

The average zone substation supplies an average 13,065 customers. A typical outdoor zone substation utilises approximately forty 22kV and nine 66kV disconnectors. Therefore buses and associated equipment are highly critical low volume assets in the distribution network. Zone substation buses and associated equipment criticality is defined by:

- Strategic impact on customer supply (If N-1 is compromised and transfer capability is limited, load shedding may be required); and
- High consequence of failure (loss of supply and OH&S issues).

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures.

For severe disconnector/bus failures that cannot be repaired within 24 hours; the location within the network determines the impact on supply to customers. The following **Error! Reference source not found.** demonstrates the various scenarios:

Table 4-35: Potential strategic failures

ZSS Configuration	Failure Item	Protection Trips to Isolate Fault	Status Post Trips	Customer Impact	Failure Category
3 transformer, no 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV B-T CB	1 transf OOS; 2 transf in service	All Customer still on supply	Serious
2 transformer, no 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV B-T CB	1 transf OOS; 1 transf in service	All Customer still on supply	Serious
3 transformer, with 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV line CB	66 kV line OOS; 3 transf still in service	All Customer still on supply	Serious
3 transformer, with 66 kV line CBs	66 kV T1-T2 Bus/disconnector	66 kV line CB & 66 kV B-T CB	1 transf OOS; 2 transf in service	All Customer still on supply	Serious

ZSS Configuration	Failure Item	Protection Trips to Isolate Fault	Status Post Trips	Customer Impact	Failure Category
2 transformer, with 66 kV line CBs	66 kV line disconnector /connection	Remote end line CB & 66 kV line CB	66 kV line OOS; 2 transf still in service	All Customer still on supply	Serious
2 transformer, with 66 kV line CBs	66 kV T1-T2 Bus/disconnector	66 kV line CB & 66 kV B-T CB	1 transf OOS; 1 transf still in service	All Customer still on supply	Serious
3 transformer	22/11 kV Transf side disc/connection	22/11kV Transf CB; 66 kV Line & B-T CBs	1 transf OOS	All Customer still on supply	Serious
3 transformer	22/11 kV Bus/disconnector	22/11 kV Transf CB & 22/11 kV B-T CB	1 Bus OOS	Customers from 1 bus off supply	*Serious or **Strategic**
3 transformer	22/11 Feeder side Dsc/connection	Feeder CB	1 feeder OOS	Customers from 1 feeder off supply	Serious
2 transformer	22/11 kV Transf side disc/connection	22/11kV Transf CB; 66 kV Line & B-T CBs	1 transf OOS	All Customer still on supply	Serious
2 transformer	22/11 kV Bus/disconnector	22/11 kV Transf CB & 22/11 kV B-T CB	1 bus OOS	Customers from 1 bus off supply	*Serious or **Strategic**
2 transformer	22/11 Feeder side Disc/connection	Feeder CB	1 feeder OOS	Customers from 1 feeder off supply	Serious

* If repairs or replacement of disconnector/bus system takes more than 24 hours the failure is considered Strategic

Criticality is further assessed for individual disconnectors and buses utilising a condition based risk model (CBRM). Condition Based Risk Management (**CBRM**), which was introduced for JEN disconnectors and buses in 2014, is utilised to predict condition into the future (Health Indices) and estimate Probability of Failure. These tools are utilised to indicate required changes to asset management plans, to develop asset investment plans using existing asset data and other information and determine when end-of-life replacement will be required. Assets with a higher health index score are targeted for further analysis before imminent replacement. For further information on CBRM, it's inputs and outputs and methodology please refer to Appendix L.

4.3.2.2 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 Critical Spares Assessment Procedure (JEM AM PR 0015). It was determined that adequate disconnector component spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team.

System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub transmission line due to a component failure.

Critical Spares Assessment Procedure (JEM AM PR 0015) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I.

Furthermore when assets are retired from service consideration is given to retaining components or entire asset as spares to service existing aging fleet.

4.3.2.3 Failure Modes

Disconnectors and bus systems are critical interconnecting assets installed to fulfil functions associated with the safe and reliable operation of the HV networks. These assets can experience insulation break down and operation defects and in rare circumstances catastrophic failure can occur.

The dominant disconnector and bus system failure modes that impact on the reliability of the network are as follows:

- failure to insulate due to lightning, over-voltages due to switching, animals and birds or insulation deterioration or pollution;
- failure to carry fault currents;
- failure to carry load due to high resistance connections resulting in thermal overheating;
- failure to open or close (disconnectors and earth switches) mechanism, linkages or contact problems that prevent the switching device from opening or closing. This will delay isolation for maintenance or fault (disconnectors) or delay applying or removing earth connection (earth switches).

4.3.2.4 Existing Controls

The following controls are common to all risks to mitigate exposure to the JEN network:

- Ongoing asset management programs as documented in Section 5.1.4.2;
- Ensure completion of programs stated in current strategy; and
- Continue to reinforce JEN internal technical standards.

It is recommended that the availability of spare wall bushings needs to be reviewed to prepare for a failure. The aim is to avoid a failure resulting in a single contingency event over a prolonged period because there is no spare wall bushing to put back into service. Two spare sets of bushings to transition between internal HV switch rooms and 66kV line entries are recommended.

Many old disconnectors are no longer manufactured and therefore spares are no longer available. A replacement program allows retired units to replenish these spares.

Some spares have been salvaged from retirement projects and left over from CAPEX projects. The brown pin and caps (66kV) are located at various ZSS, whereas 66kV post insulators are in the store. When a failure occurs, a replacement insulator may not be a direct changeover and spacers may be required to adapt to each installation.

We have 2 sets of spare 66kV surge diverters. A spare set of 22kV SD is recommended.

The contingency plan for these assets is to hold spares for each asset, that is, disconnector, earth switch, surge arrester, busbar insulators. Conductors, cable and terminations are available from general stock holdings.

Various disconnector and insulator spares are available to ensure network reliability.

4.3.2.5 Further Information on CBRM

For further information on CBRM please refer to ELE GU 0005 Condition Based Risk Management (CBRM) Application Guide. The guide provides a summary of how Jemena utilises CBRM to justify future replacement volumes for distribution and zone substation assets. It outlies the different inputs required and their associated outputs and how these outputs are interpreted.

4.3.3 PERFORMANCE FACTORS

Disconnector and busses are expected to provide their rated normal and fault level current carrying capability as well as HV insulation, isolation switching and earth switching functions when required, for a life time in the order of 50 years. Therefore all factors contributing to maintaining satisfactory condition are essential to achieve this goal.

Specific Disconnector and Bus performance measures (and condition monitoring) include assessing Buses using annual thermo-graphic surveys to identify high resistance connections. A suitable and targeted condition monitoring program has been developed to establish wall bushing condition using Dielectric Dissipation Factor testing. Dielectric Dissipation Factor testing will be used to justify condition based replacement.

Failure Prevention – avoiding catastrophic (unplanned outage more than 24 hours) disconnector/bus failures from occurring within zone substations - target **zero** pa.

Buses and connected switchgear exhibit a wear out characteristic whereby they operate for many years without significant numbers of failures and then age related or wear out failures that are not maintenance preventable begin to occur.

For zone substation buses and connected switchgear, the useful life age has been assessed as 50 years.

Aside from equipment being used within specified ratings the following affects life expectancy:

- Disconnectors, Isolators and Earth switches: are affected by the frequency of operation and the type and interval of maintenance. Corrosion and arcing shortens life;
- Connectors: are directly affected by high resistance connections. Eliminating corrosion on connectors exposed to the elements and ensuring tight connections maintains life expectancy;
- Flexible connections: are prone to becoming loose and creating high resistance joints. Furthermore, the flexible connections on earth switches may become frayed and need replacement;
- Surge arresters: are subject to moisture ingress over time;
- Wall bushings: must be monitored for surface contamination which ultimately leads to tracking. Furthermore, oil levels must be monitored to ensure dielectric strength is maintained; and
- Insulators: must be monitored for surface contamination which ultimately leads to tracking. Furthermore, pin type insulators have a history of mechanical failure

A number of factors are assessed to determine if individual assets of the disconnector and bus systems have a high probability that the unit will continue to reliably perform its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and analysis of actual performance are examined. Outputs from the CBRM model are used to provide a comprehensive assessment of disconnectors/buses condition.

CBRM outputs in the form of Health Indices shown in Section 4.2.2.3 above provide a visual demonstration the condition of the population now and into the future if no corrective measures are taken.

The following sections provide greater detail.

Condition Assessment

This section provides information about Disconnectors and Buses, as well as general information about other potential issues.

- The “duo-roll” type 66kV disconnector has a history of high contact resistance and corrosion between the clevis & the blade (aluminium tube) and between the blade and beaver tail moving contact. These types of problems lead to overheating and eventually failure if left unattended. Annual thermal scans are used to identify high resistance connections which are then programmed for replacement accordingly.
- The two sets of 22kV isolators on BD7 cable & bus side have been replaced with new AK Power 1250A isolators. Some Taplin isolators fitted to buses and feeders at BD and AW could not be opened as the contacts had welded closed. In some circumstances, the damaged contacts develop a high resistance connection, which causes the load current to flow through the latch mechanism. This results in melting of the latch lever. Defective isolators have been replaced (with AK Power units).
- 7 off 66kV AK Power disconnect switches and 4 off AK Power earthing switches at zone substation SHM (Sydenham) required retrofitting after being CRO’d due to stiffness that affected normal operation. AK Power retrofitted new pivot bearings in the centre rotating insulator stack to ensure free operation. The project was successfully completed in September 2013.
- Earth braids on ganged isolators and earth switches can sometimes be damaged if they get caught in the operating mechanism. These earth braids are replaced if there is significant damage.
- Ageing brown porcelain type 66kV and 22kV surge diverters will be co-ordinated for replacement during major construction work within a zone substation, or otherwise programmed as a separate job. Surge Diverters have a limited life and are subject to moisture ingress over time that may lead to ultimate failure. Failure of a porcelain surge diverter may create a safety concern and risk of damage to adjacent plant. Modern surge diverters are manufactured with external silicon polymer housings similar to that of new 66kV transformer bushings, which improves safety when compared to porcelain type housings.
- Brown insulators in the 66kV yard at Footscray East (FE) and possibly Heidelberg (HB) have tracking issues and burnt glazing. The insulators at ES, HB, FE and FW have been programmed to be replaced as part of major projects at the respective zone substations.
- All outdoor 22kV pin and cap type insulators under tension or shear force at various zone substations across the JEN electricity network should be replaced. Although only two ABB 22kV isolators with cracked porcelain have been found at zone substations BD and CN, there have been several failures in the distribution network. In each case throughout the JEN distribution network, the porcelain insulator has broken and was either found to be hanging from the HV conductor tail, or in some circumstances has resulted in the isolator blade collapsing during field switching. In addition to this recognised failure mode associated with the porcelain insulator, all ABB isolators installed within zone substations have an inferior latching mechanism which has a history of failure and in need of replacement. The failure of the latch to keep the isolator closed could allow it to open during heavy loads or while carrying fault currents. If the isolator opened under load conditions, customers would have a single phase HV supply or half volts on 240V supply. If the isolator opened while carrying fault currents there will be a flash over and possibly exploding porcelain insulators. Thirty four ABB (24kV, 800A Type 7502501) isolators that were defective in zone substations AW, BD, CN and YTS have now been replaced.

- In 2011 a pin and cap insulator failed in a Victorian electricity network. The failure caused the insulator to separate from its support structure, resulting in the transfer bus isolator together with the pin of the insulator and the tubular bus to be left unsupported. As a result, the tubular bus has bent due to cantilever forces, leaving the pin, isolator and tube hovering approximately 1 metre from the ground. It remained live and was discovered by personnel carrying out ground maintenance. The hovering isolator is identified by the red arrow in Figure 4–19.

Figure 4–19: Failed Pin and Cap Insulator

Porcelain has very high compressive strength (80,000 psi), sixteen times greater than its tensile strength (5,000psi). Cap and pin insulators have a generic design deficiencies when subjected to tensile forces which can lead to the porcelain cracking and eventual failure of the cement joint due to moisture ingress and increased pressure due to corrosion and thermal expansion.

Station post insulators are designed to take advantage of porcelain's compressive strength by avoiding conditions which put them in tension. Each station post section employs a large, single piece of porcelain in contrast to the cap and pin that is composed of one to three individual porcelain shells nested together and joined by cement. The simpler design and the use of fewer cemented joints means that station posts are more rigid and exhibit less deflection under load than cap and pin insulators, which is an important feature in switch applications.

The locations of all pin and cap type insulators under tension or shear force (i.e. switch insulators) has been identified. All pin and cap insulators that are in need of replacement will be replaced with station post type insulators.

The performance of the 22kV Buses at AW, BD, CN, FE and FW is continuously monitored and assessed via field surveys and condition monitoring. SBY does not warrant a replacement program as the outdoor 22kV switchyard has now been replaced with indoor metalclad switchgear. CN will be replaced as part of the switchboard replacement project in 2022-23. FE and FW will be replaced as part of the switchboard replacement project during 2020-21. AW and BD have been budgeted and a capital project will be raised to replace these during the 2021-25 EDPR period. The risk of failure of the 22kV buses is being managed by conducting thermal and corona surveys and also by PD condition monitoring using the PD Hawk.

Asset performance for disconnectors/bus systems and circuit breakers is assessed through a holistic asset management approach that includes routine maintenance, testing, diagnostic condition assessments and CBRM. This work is carried out in line with the various associated plans, policies, strategies and standards.

Asset performance measures for Jemena zone substation disconnectors/bus systems are designed to achieve a high level of reliability by undertaking a practical, cost effective program of preventive & corrective maintenance, coupled with planned, economic replacement of assets before failure; to maintain reliability and quality of supply and mitigate the safety risk to personnel and the public.

Specific disconnectors/bus systems performance measures (and condition monitoring) include the following:

- Condition monitoring tests: insulation resistance, partial discharge, dielectric dissipation factor;
- On-line, non-disruptive monitoring surveys: infrared for detecting overheating and ultrasonic detection for air borne partial discharge signals; and
- CBRM output in the form of Health Indices for present and prediction into the future without proactive intervention.

4.3.3.1 CBRM Health and Risk Analysis

Initial CBRM results indicated that the current (Year 0) health index is as shown in Figure 4–20. A total of 245 assets have been identified to be in poor condition with a higher probability of failure. These assets are located at the following locations.

Table 4-36: CBRM Output for Disconnectors and Buses – Year 0

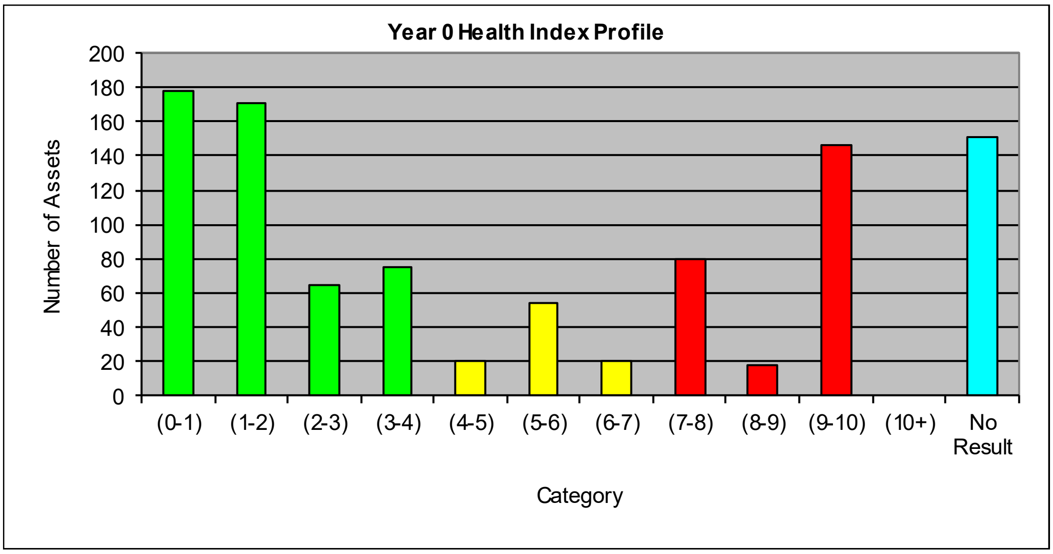
ZSS	Voltage (kV)	Qty.	Item	HI range	Comment
AW	22	26	Disconnectors/Isolators	7.70 – 9.45	Switchyards buses, disconnectors & CBs replacement 2021-25
AW	22	5	Bus	9.10	Switchyards buses, disconnectors & CBs replacement 2021-25
AW	66	3	Bus	7.70	Switchyards buses, disconnectors & CBs replacement 2026/27
AW	66	10	Isolators & earth switches	7.70	Switchyards buses, disconnectors & CBs replacement 2026/27
BD	22	33	Disconnectors/Isolators	7.08 – 9.80	Switchyards buses, disconnectors & CBs replacement 2021-25
BD	22	3	Bus	9.10	Switchyards buses, disconnectors & CBs replacement 2021-25

ZSS	Voltage (kV)	Qty.	Item	HI range	Comment
BD	66	3	Bus	7.10	Switchyards buses, disconnectors & CBs replacement 2027/28
BD	66	10	Isolators & earth switches	7.08 – 7.70	Switchyards buses, disconnectors & CBs replacement 2027/28
BLTS (MB feeders)	22	2	Disconnectors/Isolators	9.10	To be replaced with CB replacement in 2029
BY	22	1	Disconnectors/Isolators	9.10	
CN	22	38	Disconnectors/Isolators	7.08 – 9.45	Switchyards buses, disconnectors & CBs replacement 2022/23
CN	22	4	Bus	9.10	Switchyards buses, disconnectors & CBs replacement 2022/23
CN	66	1	Bus	7.70	Switchyards buses, disconnectors & CBs replacement 2022/23
CN	66	4	Isolators & earth switches	7.70	Switchyards buses, disconnectors & CBs replacement 2022/23
EP	6.6	4	Disconnectors/Isolators	9.10	Retired 2021/22 replaced by EPN
EP	66	3	Bus	7.70	Retired 2021/22 replaced by EPN
EP	66	16	Isolators & earth switches	7.70 – 9.10	Retired 2021/22 replaced by EPN
ES	66	2	Bus	7.70	To be replaced with transformer replacement project in 2019
ES	66	10	Isolators & earth switches	7.0 – 7.70	To be replaced with transformer replacement project in 2019
FE	22	6	Disconnectors/Isolators	8.75 – 9.10	To be replaced with switchgear replacement project in 2020/21
FE	22	2	Bus	9.10	To be replaced with switchgear replacement project in 2020/21
FE	66	3	Bus	6.55 – 8.75	
FE	66	7	Isolators & earth switches	7.7 – 8.75	
FF	22	3	Disconnectors/Isolators	7.70 – 9.10	To be replaced with switchgear replacement project in 2019/20
FW	22	23	Disconnectors/Isolators	8.05 – 9.45	To be replaced with switchgear replacement project in 2019/20
FW	22	1	Bus	9.10	To be replaced with switchgear replacement project in 2019/20
FW	66	1	Bus	7.70	

ZSS	Voltage (kV)	Qty.	Item	HI range	Comment
FW	66	5	Isolators & earth switches	7.70	
HB	66	2	Bus	8.75	To be replaced with transformer replacement project in 2020
HB	66	4	Isolators & earth switches	8.75	To be replaced with transformer replacement project in 2020

Total risk for all failure scenarios at Year 0 is calculated to be $66,589.

Figure 4–20: Year 0 Health Indices



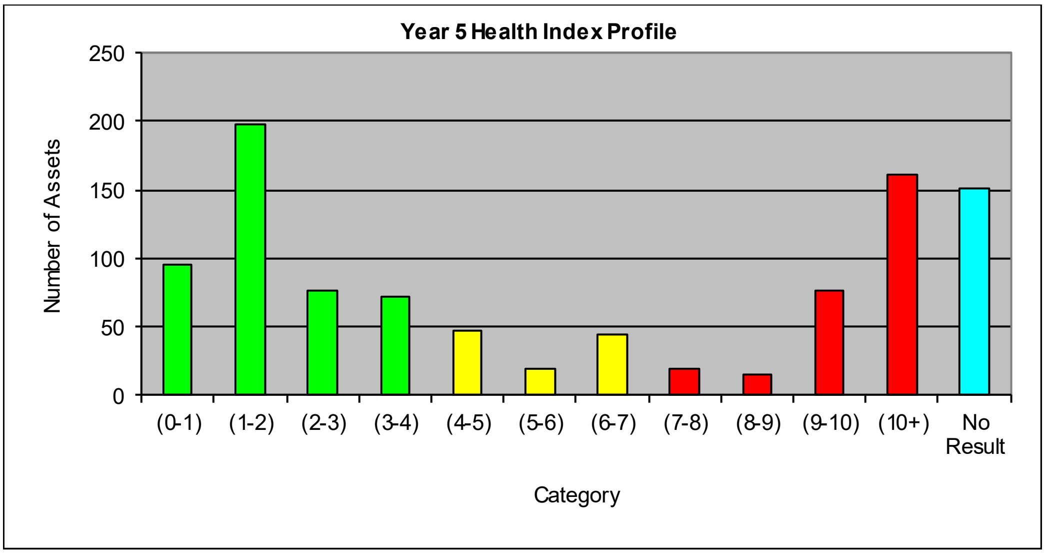
If asset replacement is deferred until 2023 (Year 5) the health index changes as shown in Figure 4–21. A total of 266 assets will be in poor condition with the associated higher probability of failure.

These assets are located at:

- AW – 44
- BD – 62
- BLTS – 2
- BY – 1
- CN – 48
- EP – 23
- ES – 12
- FE – 21
- FF – 4
- FW – 31
- HB – 8
- PV – 6

Total risk for all failure scenarios at Year 5 is calculated to be $104,477.

Figure 4–21: Year 5 Health Indices



If asset replacement is deferred until 2028 (Year 10) the health index changes as shown in Figure 4–22. A total of 325 assets will be in poor condition with the associated higher probability of failure.

These assets are located at:

- AW – 44
- BD – 64
- BLTS – 2
- BY - 1
- CN – 61
- CS – 2
- EP – 23
- ES - 14
- FE – 21
- FF -4
- FW – 43
- HB – 10
- NH – 2
- PV – 6

Total risk for all failure scenarios at Year 10 is calculated to be $168,243.

Figure 4–22: Year 10 Health Indices

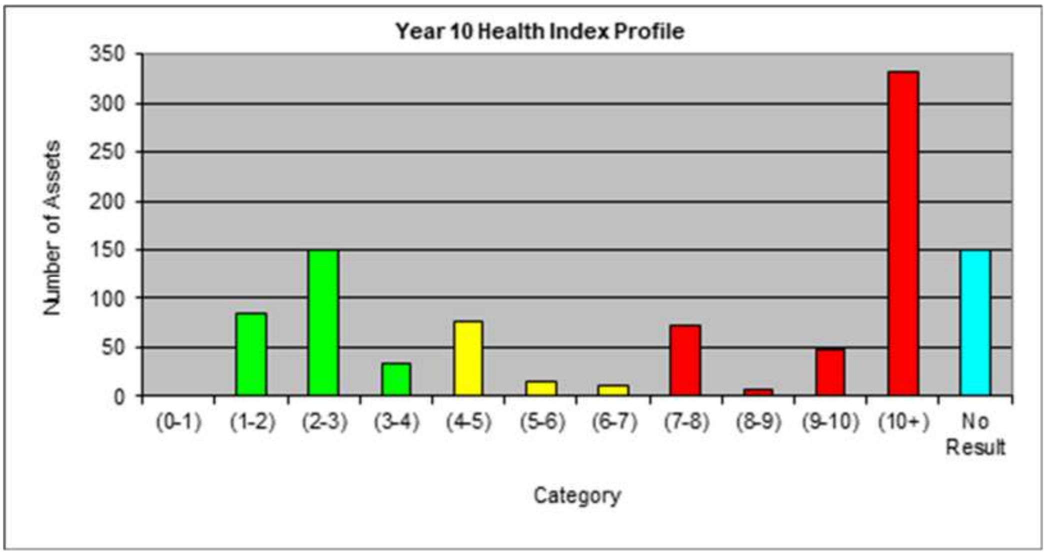


Figure 4–23: Year 15 Health Indices

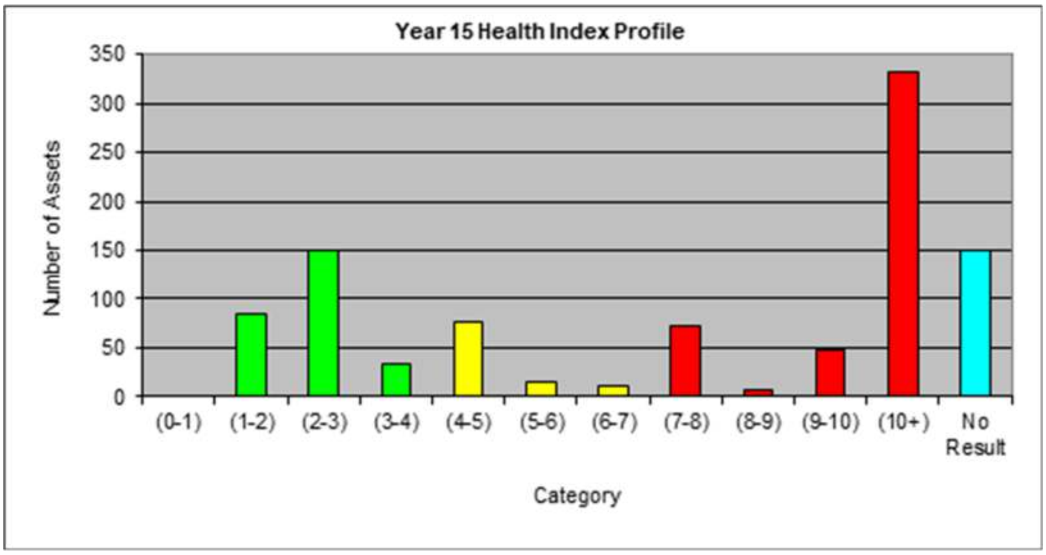
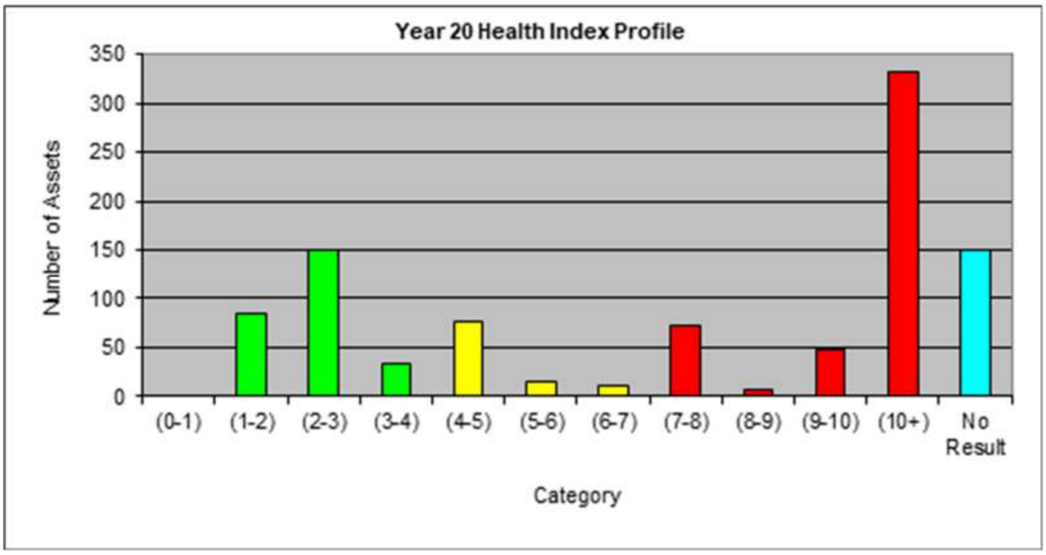


Figure 4–24: Year 20 Health Indices



If asset replacement is deferred until 2033 (Year 15) the health index changes as shown in Figure 4–23. Total risk for all failure scenarios at Year 15 is calculated to be $250,657.

If asset replacement is deferred until 2038 (Year 20) the health index changes as shown in Figure 4–24. Total risk for all failure scenarios at Year 20 is calculated to be $309,926.

These results indicate that replacement of these assets in the coming years should be undertaken in order to manage the risks associated with the number of assets in poor condition on the network.

Further scenario analysis will be undertaken to determine optimal replacement schedules however the assets identified at AW and BD as being in poor condition at Year 0 will take priority.

The JEN objective is to maximise asset life and minimise unplanned outages. In order to satisfy this objective this strategy has been developed and consists of preventive maintenance, inspections, and planned asset replacement based on rating, condition and fault history.

Control Effectiveness Controls employed are identified in Section 5.1.4.2. and condition based replacements completed are listed in Section 5.1.4.3 These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following Table 4-37.

Table 4-37: Controls effectiveness

Risk Category	Cause/incident	Controls	Incidents in past 5 years
Health, Safety & environment	Disconnector or bus failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed	Nil
Regulatory & Compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

4.3.4 LIFE CYCLE MANAGEMENT

This Section includes information about Disconnector and Bus asset management practices, including key Disconnector and Bus strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset utilisation;
- asset lifecycle management options;
- asset creation (including asset acquisition and asset spares);
- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- asset replacement and disposal; and

- future improvements

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure.

4.3.4.1 Lifecycle management options

There are four lifecycle management options:

a) Option 1: Corrective maintenance only – fix defects and failures only after they occur.

   If Option 1 is implemented, an unacceptable number of customer outages may occur due to equipment failures as per section 4.3.2.3. With a known history of high resistance connections on certain types of disconnectors, failures will inevitably occur at some stage and interrupt supply effecting customer reliability. Additionally, there will be occasions when all spares will be consumed resulting in long delays to restore the network to system normal.

b) Option 2: Preventive maintenance – a combination of routine maintenance and condition monitoring via thermal surveys and inspection.

   Option 2 is the preferred option as it addresses the dominant failure modes. The dominant failure mode that would affect supply reliability is directly related to the condition of the insulating medium. A flashover is likely to occur due to the failure of the asset to provide the required insulation.

   A further dominant failure mode describes the ability of a disconnector, or isolator, or connection to carry load. The dominant cause for this condition is a high resistance connection and an appropriate cost effective control to mitigate the risk is to use infra-red thermal survey as a condition monitoring tool to detect elevated temperatures and undertake repairs before failure (refer JEN 4365-001 Thermal Survey Policy). This condition monitoring technique and subsequent repair on detection of failure has proven successful and is applied to all indoor and outdoor buses.

c) Option 3: Condition based replacement of selected units based on required ratings, condition and/or availability of spare parts for repairs.

   As part of the load growth capital planning process, under-rated disconnectors can be identified and economically justified for each project. This option is not acceptable because only under-rated or defective units are replaced and it does not take into account units that present with a deteriorated condition and high risk of failure.

d) Option 4: Replacement of all units based on age (older than 55 years)

   Option 4 is not a cost-effective solution as some units will be replaced prematurely whilst still in a serviceable condition and their rating is adequate for their application.

   Disconnectors and Isolators have the largest volume of aging assets as per section 4.3.1.2. Disconnectors and Isolators have a useful life of approximately 50 years. Currently there are 38 Disconnectors and/or Isolators which are greater than 50 years in age and still in serviceable condition.

   Buses are the other asset group which has aging assets as per section 4.3.1.2. Currently there are 3 buses which are greater than 50 years in age and still in serviceable condition.

4.3.4.2 Creation

Working assets are effectively created via acquisition, upgrades or replacement or the deployment of spares when available.

Four scenarios trigger the need to acquire and connect new Disconnectors and Buses:

- As part of a new zone substation development;
- As a part of an existing zone substation capacity upgrade;
- To replace old assets that have reached end-of-life; and
- Manufacturing or design defect(s).

4.3.4.3 Asset Operation and Maintenance

This section provides information about the current asset maintenance program for Disconnectors and Buses.

The current asset maintenance program involves

- Inspection;
- Reactive and corrective maintenance;
- Preventive maintenance; and
- Condition-based monitoring

Inspection

Zone substations are inspected monthly by operating personnel and annual engineering audits are conducted by the Primary Plant & Distributions Systems. The following equipment is assessed:

- Buses are assessed using annual thermo-graphic surveys to identify high resistance connections.

  Because indoor buses do not get washed naturally by rain, maintenance of all indoor 66kV buses and associated switchgear has been implemented. Indoor air insulated type 66kV buses are maintained at the same time as disconnectors.
  Outdoor buses are inspected and insulators cleaned. Maintenance work involves close inspection, checking of connections, and cleaning of insulators, earth switches, surge diverters and wall bushings.

- Disconnectors, isolators and earth switches are mechanical devices and need to be assessed on case-by-case basis taking into consideration the amount of deterioration, age and if the equipment has been fitted with a CRO (caution regarding operation). All disconnectors, isolators and earth switches must operate freely and have clear readable signage. The maintenance of disconnectors includes disassembly, cleaning, lubricating, adjusting and functional testing.

  There are some 22kV load break disconnects used to de-energise HV plant that required the same maintenance as 66kV disconnectors. Also the integrity of all earth switches needs to be assured and consequently all earthing switches are similarly maintained.

- 22kV feeder surge arresters are a run to failure plant item, however if surge arresters are identified as end of life due to age, tracking etc. they will be replaced as part of maintenance works or an applicable project. 66kV surge arresters are tested by measuring insulation resistance.

- The surface condition of wall bushings (i.e. presence of cracks and/or tracking) and oil levels is currently assessed during annual engineering audits using binoculars. Furthermore, wall bushings are DDF tested every 5 years and if required replacement strategies are implemented.

DDF testing is used to indicate the presence of moisture in the bushing. Moisture penetration of bushings can lead to electrical discharge and failure. The internal failure often results in explosion. Experience with transformer bushings indicates that the probability of moisture ingress increases with age and consequently it is important that the moisture content of the bushings is verified by DDF measurement. Typically the failure of a wall bushing introduces a hazard to people in the surrounding area. The JEN network does not have a history of wall bushing failures but with an aging fleet of wall bushings it is seen as a proactive measure. In 2010 the primary plant group implemented DFF testing on all wall bushings across the JEN network that are greater than 30 years of age. However access to wall bushing due to working at height issues has slowed the testing program.

Reactive and corrective maintenance

Reactive and corrective maintenance is performed to repair defects identified during in-service inspection (i.e. monthly operator inspections or annual engineering audits), routine maintenance or by thermal surveys. The typical corrective maintenance includes checking connections and cleaning of insulators, earth switches, surge diverters and wall bushings. Maintenance of disconnectors includes disassembly, cleaning, lubricating, adjusting and functional testing.

Regular monthly operator inspections to identify defects and annual thermal surveys to detect high resistance connections of all plant and equipment has been scheduled in SAP. Any abnormalities identified either during inspection audits or during switching should be reported to assess asset performance and adjust maintenance intervals.

Preventive Maintenance

The preventive maintenance program for Disconnectors and Buses shall consist of:

- Indoor 66kV buses and associated plant shall be fully maintained on a 6 year cycle;
- 66kV wall and floor bushings shall be maintained with the 66kV indoor buses on a 6 year cycle;
- Outdoor 66kV disconnects, isolators and earth switches will be fully maintained on a 6 year cycle;
- Outdoor 22kV disconnect switches used to interrupt load to de-energise plant will be fully maintained on a 6 year cycle;
- All 22kV HV earth switches will be fully maintained on a 6 year cycle; and
- Motor Operated Disconnectors (with automation isolation requirements) will be functionally operated and checked every 12 months.

Routine full preventive maintenance shall include cleaning, checking of contacts, spring tension and resistance measurement, lubrication & functional tests and is to be performed as part of an outage of the associated major plant items (e.g. bus, line, feeder, transformer).

Condition-Based Monitoring

Condition-based monitoring programs involve Infra-red thermal imaging. The thermal imaging of buses is carried out as part of the general program for the monitoring in zone substations. It is intended to identify any external problems associated with poor connections or auxiliary equipment operating with abnormal temperature rises.

Future Improvements

A wall bushing DDF (Dielectric Dissipation Factor) testing program is currently in progress. The program and its associated results are continually monitored and evaluated. The following future improvements are currently being considered:

Purchasing a partial discharge set to perform off line bushing tests; This has been purchased and working well.

Utilise the PD Hawk to perform RF tests within zone substation switchyards to detect and locate internal and surface PD activity; and

Maintenance in the form of insulator washing, which includes a close live line inspection of the insulator, is an effective means to mitigate the risk of insulator failure. Future requirement to wash insulators can be evaluated on a case by case basis.

4.3.4.4 Asset Replacement/Disposal

Although some disconnectors, isolators and buses have continued to operate satisfactorily for over 50 years, a 50-year-old disconnector, isolator or bus is approaching the end of its practical life. It is paramount to have replacement plans to avoid equipment failure and also avoid large volumes of equipment replacement in short time periods. Ultimately replacement plans maintain network reliability through preventing failures and therefore also maintain personnel safety within zone substations

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

Table 4-38 lists the forecast capital expenditure (**CAPEX**) replacement volumes for zone substation disconnectors and buses from 2018 to 2030, based on these drivers.

Table 4-38: Forecast Replacement Volumes - Zone Substation Disconnectors

Replacement Volumes – Zone Substation Disconnectors and Buses	Unit	Year											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
22kV isolator replacement AW	ea								All				
22kV isolator replacement BD	ea									All			
22kV isolator retirement CN	ea				All								

Typically when disconnectors, isolators, earth switches and bus conductors are retired or replaced any useful spares are retained and the remainder are sent to scrap metal. Surge arrestors and insulators have no retainable spares and are not suitable as scrap metal and are disposed of accordingly. When 66kV wall bushings are disposed of they are drained of oil, tested for PCB's, and placed in the porcelain bin at Tullamarine depot.

Before any equipment is disposed of it must be assessed by the Asset Engineering group for retainable spares. If other similar plant is contained on the JEN network, all applicable parts will be tested and retained as spares

4.3.5 INFORMATION

Jemena's AMS provides a hierarchical approach to understanding the information requirement to achieve Jemena's business objectives at the Asset Class. In summary, the combination of Jemena's Business Plan, the individual Asset Business Strategy (ABS) and Asset Class Strategy (ACS) all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives**Error! Reference source not found.**. Table

4-40 identifies the current and future information requirements to support the Sub Asset Class critical decisions and their value to the Asset Class. Table 4-41 provides the information initiatives required to provide the future information requirements identified in Table 4-40. Included within this table is the risk to the Sub Asset Class from not completing the initiative.

All of the information required by the transformer Sub Asset Class is available within Jemena's current business systems.

Table 4-39: Disconnectors and Buses Business Objectives and Information Requirements

Business Objective	Jemena Information Sources	Externally Sourced Data
Maintain Safety, availability and reliability of Disconnector and Buses	SAP. DrawBridge Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee. Alerts – from DB's and Government Organisations and manufacturers. Manufacturing manuals. AS/IEC standards.

Table 4-40: Disconnectors and Buses Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with Justification)
Disconnectors And Buses - Asset Creation	Specifications and tender responses Zone Substation Primary Design Standard New asset project progress reporting. Completion recorded in SAP Asset register in SAP		High: Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of Disconnectors and Buses via Inspections, and audits	Asset register SAP, with details of each asset and significant components; Manufacturer Type Equipment description Construction year Basic specification Voltage Current Location: Zone substation name Address Condition Monitoring Maintenance reports & Test reports Performance history • Daily situation reports • Investigation reports (ECMS) • Plant defect reports	Migrate Condition & Performance reports/data into SAP to improve analysis and decision making. Photograph Disconnect nameplate and attach to SAP equipment Access all information via electronic tablet in the field.	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with Justification)
	DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts SMI's – (Standard maintenance instruction) SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP		
Maintain functionality of Disconnectors and Buses via Preventive Maintenance	Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. Scheduled task description, timing and completion recorded in SAP; SMIs held in Sharepoint, Policies & Forms. Manufacturers maintenance manuals SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP Details of spare equipment located in SAP OPEX & CAPEX cost reporting recorded in SAP	Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	High: Regulated to maintain supply reliability, safety and quality of supply
Maintain functionality of Disconnectors and Buses via Condition Monitoring	Condition monitoring tasks, schedule in SAP and results stored in proprietary test equipment data base in SAP. Scheduled task description, timing and completion recorded in SAP. Outputs from condition monitoring analysis	Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	High: Regulated to maintain supply reliability, safety and quality of supply
Respond to Disconnector and Bus defects	Alerted via JEN Control Room or situation report.	Although hard copies of	High: Regulated to maintain supply

Critical Business Decision	**Current Information Usage**	**Future Information Requirement**	**Value to Asset Class (High, Medium, Low with Justification)**
/ faults to restore equipment operationally. Perform corrective maintenance.	Asset register SAP, with details of each asset and significant components; Manufacturer Type Equipment description Construction year basic specification Voltage Current Location: Zone substation name Address SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP Condition Monitoring Maintenance reports & Test reports Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts Asset failure details and investigation reports Details of spare equipment located in SAP Opex & CAPEX cost reporting recorded in SAP	manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in in Drawbridge. Manufactures manuals for older assets may not be available. Access all information via electronic tablet in the field. All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner. Update asset data in SAP for missing data.	reliability, safety and quality of supply
Disconnectors and Buses – Condition Based Risk Management (CBRM)	CBRM analysis Health Index Held by Primary Plant Distribution Systems Group		High: Regulated to maintain supply reliability, safety and quality of supply
Disconnectors and Buses – Rating suitable for load demand	ZSS load forecast in ECMS Published annual Distribution Planning Report available on Jemena website		High: Regulated to maintain supply reliability, safety and quality of supply
Asset Class Strategy Review	Condition data Fault/failure data		Medium: Allows strategy to be fine-

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with Justification)
	Maintenance & replacement costs AMS		tuned when changes to performance and/or costs or environment alter

Table 4-41: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph disconnector nameplate and attach to SAP equipment Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	To improve analysis and decision making. Asset data available from business systems saving on site trips. To utilise full emergency rating of a transformer during system abnormal operating conditions.	Poor efficiency in accessing asset data and delayed response when transformer full ratings are required.	Transformer emergency rating and recommendation guideline will ensure accurate assessment and improved understanding in Asset management. Asset Data as per RCM and SAP requirements.

4.4 ZONE SUBSTATION INSTRUMENT TRANSFORMERS

4.4.1 Introduction

The Instrument Transformer ACS applies to Instrument Transformers installed on the 66kV, and 22kV, JEN networks. The 11kV, 6.6kV and most 22kV networks utilise metalclad switchgear.

This strategy applies to stand-alone instrument transformers and does not apply to instrument transformers fitted within metalclad switchgear, power transformers or capacitor banks as they will normally be maintained and replaced together with the major asset.

The Zone Substation Instrument Transformer Asset Sub-Class Strategy provides an asset overview, while identifying the best strategies and plans for managing assets over their lifecycles.

The Asset Sub-Class Strategy is based on key information about each asset (including risk, performance, capital expenditure and operational expenditure). Based on this information, the Asset Sub-Class Strategy provides details about the Jemena Electricity Network's (**JEN**) zone substation instrument transformer asset class strategies for the next five years, and comprises five key areas:

- Asset class profile includes information about the type, specifications, life expectancy and age profile of zone substation instrument transformers in service across the JEN.
- Asset strategy outlines zone substation instrument transformer asset management practices. This includes key zone substation instrument transformer strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and programs of work. See Section 4.4.7 Life Cycle Management.
- Asset risk includes information about asset risk, including causes and consequences. See Section 6.1.2 Risk.
- Asset performance provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with zone substation instrument transformer management. See Section 4.4.6 Performance.
- Asset expenditure assessment provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

This Section includes information about the type and specifications of the instrument transformers in service across the JEN.

Instrument transformers are high accuracy class electrical devices used on the JEN to transform voltage or current levels. The most common usage of instrument transformers is to operate instruments or metering from high voltage or high current circuits, safely isolating secondary control circuitry from the high voltages or currents. The primary winding of the transformer is connected to the high voltage or high current circuit, and the meter or relay is connected to the secondary winding.

4.4.2 Voltage Transformers

In each zone substation, the 22kV, 11kV and 6.6kV systems typically have a voltage transformer (**VT**) installed on each bus or on the secondary of each transformer for voltage control, protection and metering.

On the 66kV system, VTs are usually single phase, oil-immersed types fitted with porcelain or polymeric bushings. They may be either magnetic or capacitive coupling types, which are generally hermetically sealed. In some cases, 3 phase 66kV oil filled VTs have been installed for protection and metering.

4.4.3 Current Transformers

Current transformers are installed on feeders, buses and transformer circuits to satisfy the requirement of various protection schemes such as overcurrent, earth protection and metering purposes. All CT's are single phase and can be grouped as follows:

- Oil immersed type inside bulk oil circuit breakers;
- Oil immersed type post CTs
- Dry synthetic epoxy resin types supplied together with vacuum or SF6 dead tank circuit breakers;
- Oil immersed types inside power transformers; and
- Dry synthetic epoxy resin types supplied together with metalclad switchboards

This strategy applies to stand-alone instrument transformers and does not apply to instrument transformers fitted within metal clad switchgear, power transformers or capacitor banks.

4.4.4 Asset Specification

Table 4-42 identifies the number, type and construction year of instrument transformers installed across Zone Substations on the JEN network. CS, FT, NH, NS and NT do not contain applicable instrument transformers as they are mounted within metal-clad switchgear and inside transformers.

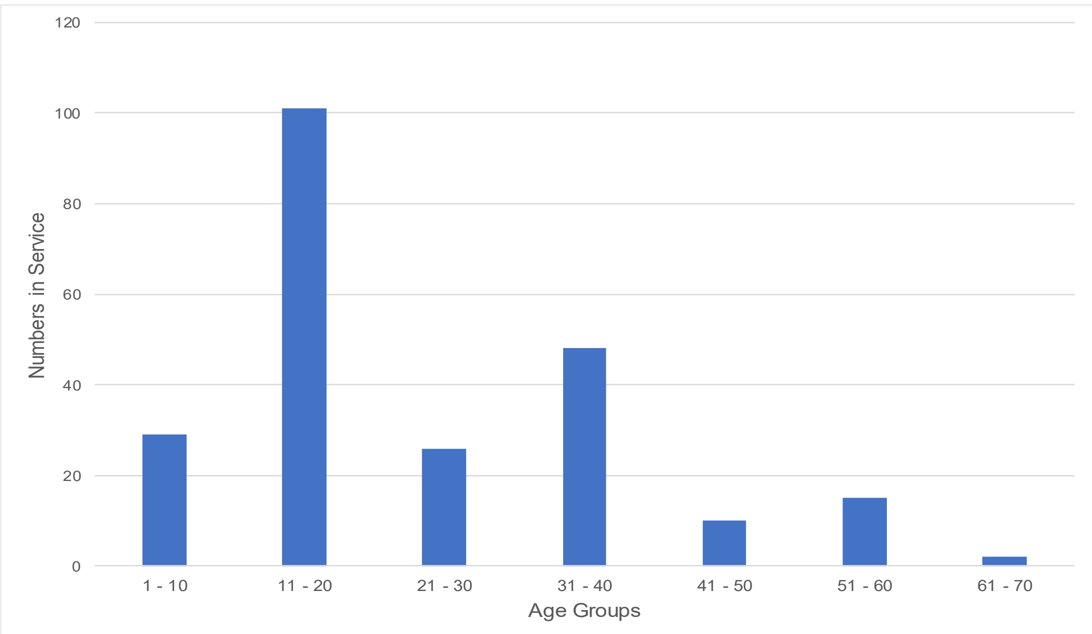
Table 4-42: Instrument Transformer Information

Zone Substation	Installation Year (Range)	Number of CTs per Ph	Number of VTs
AW (Airport West)	1964 – 2001	9	4
BD (Broadmeadows)	1961 – 2002	21	5
BMS (Broadmeadows South)	2014	0	6
BY (Braybrook)	1999	6	4
CN (Coburg North)	1967 – 2001	15	6
COO (Coolaroo)	2006 – 2007	0	6
EP (East Preston)	2003	3	0
EPN (East Preston)	2015	0	6
ES (Essendon)	2003	3	0
FE (Footscray East)	1999 – 2010	3	3
FF (Fairfield)	1955 – 1960	0	3
FT (Flemington)	N/A	N/A	N/A
FW (Footscray West)	2008	0	3
HB (Heidelberg)	2010	3	3
MAP (Melbourne Airport)	2002	3	2

Zone Substation	Installation Year (Range)	Number of CTs per Ph	Number of VTs
NEI (Neilson)	1990	6	6
NH (North Heidelberg)	N/A	N/A	N/A
NS (North Essendon)	N/A	N/A	N/A
NT (Newport)	N/A	N/A	N/A
PTN (Preston)	2019	0	6
PV (Pascoe Vale)	2011	0	6
SBY (Sunbury)	2013, 2018	3	13
SHM (Sydenham)	2007	0	6
SSS (Somerton Switching)	2001	12	8
ST (Somerton)	2001	0	6
TH (Tottenham)	1984	3	0
TMA (Tullamarine)	2015	0	6
VCO (Visy Coolaroo)	1988	3	6
YVE (Yarraville)	2014	3	6

The age profile of the 231 Instrument Transformers installed on the JEN is shown in Figure 4–25. The majority of JEN instrument transformers were installed between 1980 and 2005.

Figure 4–25: Instrument Transformer Age Profile



4.4.5 RISK

This section includes information about instrument transformer risk profiles involving the way that asset class criticality is established, the risks posed by instrument transformer 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 instrument transformers.

This information specifically involves:

- Asset class criticality score (sub asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Existing controls;
- Asset Spares;
- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

Instrument Transformers are generally very reliable and the risk of failure is considered to be low. The major risk associated with instrument transformer operation has been identified as personnel safety in the event of potential failures. For more information about instrument transformer risk analysis, see JCARS[9].

Emerging risks for this asset class include:

- Ageing population;
- Deteriorating interior insulation condition of oil/paper insulation system due to heat and electrical stress by being in-service;
- Deterioration of sealing systems allowing moisture and oxygen into insulation system;
- Expenditure prioritisation restricting timely replacements; and
- Managing population of CT's with 5 Amp secondaries with emerging new technology to introduce 1 Amp CT secondaries, including spares.

4.4.5.1 Criticality

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub asset class level by following the Asset Criticality Assessment Procedure (JEM AM PR 0016). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of Jemena'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 instrument transformer has an asset criticality score of AC2 (Moderate) due to operational and health and safety consequences associated with failures.

[9] For more information on JCARs please click here.

JEN zone substations supply an average of 13,065 customers and contain an average of 8.4 instrument transformers. Instrument transformers are a low volume asset with high criticality which is defined by:

- A severe failure of protection CT's takes the bus protection out of service and restricts the operation of the substation severely. The strategic impact on customer supply may be affected (If N-1 is compromised and transfer capability is limited, load shedding may be required);
- Long lead time for repair or replacement (procurement of a new instrument transformer is typically 4-6 months), unless spares are purchased, then replacement can be undertaken within 24 hours; and
- High consequence of failure (loss of supply and OH&S issues). On specific post type CT's, when the unit fails their porcelain housing shatters. The broken pieces can travel many metres and cause serious damage to adjacent equipment and injury to personnel.

Failures that result in loss of supply to greater than 3,200 customers (loss of a bus or whole Zone Substation) for greater than 24 hours are classified as Strategic failures. Provided spares are available to replace a failed CT or VT, it is not expected outages will exceed 24 hours.

However, if spare units are not available or an explosive failure damages adjacent assets, strategic failures may occur.

Typical Instrument Transformer faults include:

- Internal insulating column breakdown failure due to oil/paper deterioration, electrical stress or moisture ingress;
- External housing insulation failure (flashover) due to lightning, animals and birds or pollution; and
- Thermal failure due to a deteriorated or high resistance joint or connection

The consequences resulting from these faults can include:

- Housing failure and associated explosion and flying porcelain and or metal pieces; and
- Oil spillage and possible fire;

Destruction of complete unit and possibly damage to adjacent assets.

4.4.5.2 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 Critical Spares Assessment Procedure (JEM AM PR 0015). It was determined that adequate instrument transformer spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team.

System planning studies are conducted to ensure continuity of supply for a loss of a single zone substation transformer or loss of a single sub transmission line due to an instrument transformer failure.

Critical Spares Assessment Procedure (JEM AM PR 0015) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I.

Furthermore when assets are retired from service consideration is given to retaining components or entire asset as spares to service existing aging fleet.

A spare set of 66kV VT's was purchased as part of the 2014 project to replace the defective VT at SBY: Installation of 3 66kV VT's at SBY (BAA-RSA-000029). Currently JEN does not have a spare set of three 66kV CT's. The current spares policy proposes maintaining a complete fleet of spare 66kV sub transmission instrument transformers to ensure network reliability is maintained. Spares will be collected from various ZSS augmentation projects.

4.4.5.3 Failure Modes

Instrument transformers are critical assets installed to fulfil protection and metering functions associated with the safe and reliable operation of the HV networks. These assets can experience insulation break down and in rare circumstances catastrophic failure can occur.

The dominant CT & VT failure modes that impact on the reliability of the network are as follows:

- failure to insulate (external)due to lightning, over-voltages due to switching, animals and birds or insulation deterioration/contamination or pollution;
- failure to insulate (internal) due to deteriorated paper/plastic insulation material, poor condition insulating oil, PD tracking and breakdown due to moisture ingress or oil/paper system contamination during manufacture;
- failure to carry fault currents;
- failure to carry load due to high resistance connections resulting in thermal overheating; and
- Destruction of complete unit and possibly damage to adjacent assets;

4.4.5.4 Existing Controls

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 6.1.4.3, together with initiation of replacement projects for assets determined to in danger of major failure.

4.4.5.4.1 Contingency

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the failed CT or VT. Once determined, either components are replaced or whole unit replaced with a spare from stock. In lieu of replacing defective 66kV post CT's, the live tank circuit breaker can be replaced with a dead tank CB with integral CT's. Spare 66kV and 22kV post CT's are stored at the Tullamarine depot.

4.4.6 PERFORMANCE FACTORS

CTs are expected to withstand their rated normal and fault level current carrying capability and deliver rated secondary current signals whilst VTs are expected to withstand normal and temporary over-voltages and deliver rated secondary voltage signals. as well as maintaining HV insulation for a life time in the order of 50 years. Therefore all factors contributing to maintaining satisfactory condition are essential to achieve this goal.

Historically Instrument Transformer performance measures (and condition monitoring) has included infra-red thermal imaging to identify hot spots and visual inspections to identify defects. Historically instrument transformers have been reliable items of plant with 3 (CN, ES and SBY) failures in the past 20 years. A suitable and targeted condition monitoring program that includes DLA testing and Partial Discharge testing was implemented in 2014 and 2015 respectively. The DLA and Partial Discharge conditioning monitoring results will be recorded and monitored, so the assets performance can be assessed in the future and prioritised for replacement. Currently condition monitoring is the primary driver used to determine instrument transformer condition.

Performance requirements/targets:

Failure Prevention – avoiding catastrophic (unplanned outage more than 24 hours) instrument transformer failures from occurring within zone substations.- target **zero** pa.

The design life expectancy of an instrument transformer is approximately 50 years. However, when primary plant is replaced usually instrument transformers are upgraded.

Condition Assessment

This section provides information about Instrument Transformers, as well as general information about other potential issues on the JEN network:

- The replacement of ASEA IMBA oil immersed 66kV post CT's associated with outdoor minimum oil breakers was completed some years ago. This was undertaken due to known incidents of explosive failure. Consequently all other instrument transformers will be monitored & replacement plans established when condition indicates end of life is approaching. Condition monitoring tests as per section 6.1.4.3 (Condition Monitoring) are used to monitor and prioritise replacement.
- The Crompton Greaves 66kV VT's installed at CN on the TTS line have been inspected for condensation within the sight glass. The bellows are constructed from stainless steel.
- The polycarbonate sight glass on the Crompton Greaves 66kV VT's installed at AW (KTS line) had deteriorated and was replaced. This revealed that the red phase bellows were 5mm above the minimum oil level and no oil leaks were visible. The white and blue phase VT bellows were approximately 25mm above the minimum level at an ambient temperature of 21 degC. It was noted the manufacturer states, that the bellows level should be half way between Min and Max at 30 degrees. Crompton Greaves Power has reviewed the information regarding this VT and the adjacent units, and advised that since there is no oil leak, the VT can remain in service. The bellows should be monitored.
- The white phase CVT on the No.6 66kV bus at SBY had a severe oil leak identified during a routine engineering audit. Repairs were attempted on site but were unsuccessful. Later during a site inspection, it was identified that the leak had developed further. The CVT was subsequently taken out of service for further repairs. After consultation with ABB and Tyree it was found that the CVT had lost two thirds of its oil and could not be repaired. This affected the KTS 66kV line protection and station security as this CVT is used to provide the potential supply to the KTS 66kV line distance protection. These Tyree CVTs are common in JEN zone substations, they are prone to leaking and are not repairable. It is for this reason that the red and blue phase CVTs on the No.6 66kV Bus at SBY were replaced with new VTs and an additional set purchased and kept as spares should a similar scenario occur in other zone substations. This is in consideration of the long lead time of 25 weeks to procure new VT's.
- On the 2nd of February 2014 the new ABB type 2GSA MVT's that replaced the existing CVT's on the No.6 66kV at SBY bus failed catastrophically after being in service for approximately 4 months. Investigations have revealed that a further 13 of the same type ABB MVT's are located within the JEN electricity network. Primary Plant is currently worked alongside ABB to help diagnose the internal mode of failure. A detailed Incident Investigation was prepared and action items completed. This included testing similar units on the JEN network.
- A project had been initiated to purchase and install 3 off 1-phase 22kV CTs at ZSS CN for CN11 feeder CB. The white phase of the existing 22kV CT is leaking oil. A temporary repair was carried out and 11 litres of oil was added on 11/07/2013. The repair resulted in reducing the severity of the oil leak; however it didn't completely stop it. The CT was being monitored and oil topped up every 2 weeks until it is replaced. Feeder CN11 supplies a Co-Gen customer and a failure of the white phase 22kV CT will result in the disconnection of the Co-Gen customer from the Jemena Electricity Network for the duration of the outage. In addition to the disconnection of the Co-Gen customer, JEN customers supplied from feeder CN11 will also be also disconnected. The CT's on feeder CN11 have been replaced.

- The Conelec 66kV CT's have been replaced as part of the 2015 business case to replace the 1-2 66kV Bus-Tie CB at ZSS ES (BAA-RSA-000071). These CT's have condition issues that were identified during the DLA testing program that was implemented in 2014. The condition issues relate to DLA values that were around the 1% range. There is industry knowledge of explosive failure of CTs with DLA readings >1%. Failure of the CTs will have a significant impact on the security and reliability of supply to all customers supplied from zone substation ES (Essendon).

4.4.7 UTILISATION

Instrument transformers are permanently connected to the system to provide metering and protection in terms of current and/or voltage. As a result, their utilisation is virtually continuous. Current transformers are operated within their rated normal and fault current carrying ratings. Voltage transformers are operated within their normal and overvoltage ratings.

4.4.8 CONTROL EFFECTIVENESS

Controls employed are identified in Section 6.1.4.3. and condition based replacements completed are listed in Section 6.1.4.4 These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following Table 4-43.

Table 4-43: Controls Effectiveness

Risk Category	Cause/incident	Controls	Incidents in past 5 years
Health, Safety & environment	Instrument Transformer failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed	MVT Feb 2014 at SBY One at CN One at ES
Regulatory & Compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	as above projects
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

4.4.9 LIFE CYCLE MANAGEMENT

This chapter includes information about instrument transformer asset management practices, including key instrument transformer strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset utilisation;
- asset lifecycle management options;

- asset creation (including asset acquisition and asset spares);
- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- asset disposal; and
- future improvements

4.4.9.1 Asset Lifecycle Management Options

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure.

The preferred asset lifecycle management option involves condition monitoring and preventive maintenance, with the aim of achieving at least 50 years of asset life before replacement.

There are three feasible lifecycle management options:

a) Condition monitoring, preventive maintenance and condition based replacement

   Condition monitoring is limited to operators and engineers performing monthly and yearly audits, thermal imaging and detailed inspections that are conducted as part of maintenance works associated with applicable plant. The in-service reliability of instrument transformers has been high with 2 failure occurring from the 231 in-service instrument transformers. These failures occurred at zone substations SBY in 2013 and ES in 2015. A suitable and targeted condition monitoring program has been developed to establish instrument transformer condition, so that condition based replacement can be planned as required. This program has been employed to test VT's and CT's as per section 4.4.7.4. Since modern types of instrument transformer have failed, a rigorous testing program may be necessary. The entire condition based testing program should be reviewed and consideration to test younger instrument transformers is recommended. SAP maintenance plans need to be created once a new testing interval has been established.

   Furthermore, all other instrument transformers that have reached a 40 year life need to have maintenance plans scheduled in SAP for condition testing. This needs to be monitored and maintenance plans created.

   All new installations will be DLA and PD tested as part of the commissioning program.

b) Inspection, corrective maintenance and fixed, age-based replacement (irrespective of condition)

   Condition monitoring and maintenance as per Option 1 with replacement at a nominated age of say 40 years, which is the expected useful service life with low probability of failure. This option is not considered to be cost-effective as assets in good condition will be replaced prematurely. Condition monitoring and preventive maintenance can be employed to defer capital replacement, and assets will then be replaced to mitigate safety risks and reduced reliability risks.

c) Run-to-failure replacement

   Condition monitoring and maintenance as per Option 1 with replacement upon failure. This is not an option due to the criticality of the assets (instrument transformers). Run to failure will impact on health and safety and have a negative impact on supply reliability. Furthermore, the risk to the network due to long lead times when procuring replacement assets can be mitigated by purchasing spares.

4.4.9.2 Creation

Working assets are effectively created via acquisition or the deployment of spares.

Three scenarios trigger the need to acquire and connect new Instrument Transformers:

- As part of a new zone substation development;
- As a part of an existing zone substation capacity upgrade; or
- To replace old transformers that have reached end-of-life

4.4.9.3 Asset Operation and Maintenance

The current asset maintenance program involves:

- Inspection;
- Reactive and corrective maintenance;
- Preventive maintenance; and
- Condition-based monitoring.

4.4.9.4 Inspection

Condition monitoring is the primary driver used to determine VT and CT condition. Historically visual and thermal (infra-red) inspections have been used as analysis tools, however a DLA testing program was implemented in 2014 to further determine the condition of instrument transformers. DLA testing is used to assess insulation condition to detect defects like water trees, electrical trees, moisture and air pockets so instrument transformers can be prioritised for replacement before failure occurs.

Partial discharge is a prominent cause of high voltage system failures. In late 2014 partial discharge testing equipment was purchased and testing of instrument transformers began in 2015. Partial discharge testing assesses the quality of equipment’s insulation and overall equipment health. Partial discharge testing aims to find the following before failure occurs:

- Corona discharges;
- Surface discharges;
- Discharge in laminated material;
- Cavity discharges; and
- Treeing.

Ultimately, the purpose of introducing Partial Discharge and DLA testing is to:

- Prevent failures;
- Improve safety;
- Decrease costs;
- Reduce capital expenditure and loss of supply; and
- Manage maintenance, refurbishment and replacement.

The condition monitoring and testing of instrument transformers may determine whether the maintenance regime will be modified to address defect issues or the asset may be prioritised for replacement as part of a capital program.

Although there are many instrument transformers on the JEN network, the in-service reliability has been high. Their reliability performance can be maintained with minimal work as described below:

- Operators visually inspect instrument transformers external to major plant items when visiting substations to detect any obvious defects. Checks are to be made for signs of oil leaks, tank distortion, and damage to bushings and leads. Engineers also conduct annual zone substation audits identifying any obvious defects.
- The thermal imaging of instrument transformers is carried out annually as part of the general program for condition monitoring of all zone substations assets. It is intended to identify any external problems associated with poor connections operating with abnormal temperature rises.
- Detailed inspections are conducted as part of maintenance works associated with the applicable plant (circuit breaker, bus or line) as appropriate.

4.4.9.5 Reactive and corrective maintenance

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified faults (or both). Oil testing, refilling and repairs of instrument transformers is a specialised field of work that needs to be assessed on a case by case basis.

4.4.9.6 Preventive maintenance

Instrument transformers are serviced as part of the maintenance on the associated major plant item. For example, current transformers with their associated circuit breakers and voltage transformers as part of bus maintenance. This maintenance is limited to checking connections, cleaning, and testing insulation resistance.

Oil testing, refilling and repair of instrument transformers is a specialised field of work that needs to be assessed on a case by case basis. Hermetically sealed instrument transformers should not have their seals disturbed unless deemed necessary. Oil sampling and testing of instrument transformers operating at 66kV and below has generally not been implemented by the Electricity Supply Industry, as the risk of contamination and subsequent failure is considered to be high. A diagnostic condition monitoring program will be considered in lieu of oil sampling.

Insulation resistance measurement is to be conducted on instrument transformers to monitor their condition. For sub-transmission oil-filled instrument transformers, once over 40 years old, a comprehensive set of condition monitoring tests (Insulation Resistance, Partial Discharge, Dielectric Dissipation Factor and Capacitance) is to be conducted. These tests are to be conducted at 5 yearly intervals unless results show rapid degradation over time, in which case, are to be conducted at more frequent intervals.

4.4.9.7 Condition-based monitoring

Jemena’s condition-based monitoring programs involve:

- Visual inspections performed monthly by operators and yearly by engineers;
- Infra-red thermal imaging;
- Detailed inspections conducted as part of maintenance works on specific plant; and
- DLA and PD testing

4.4.9.8 Asset Replacement/Disposal

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how Jemena prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-44 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure.

Table 4-44: Asset Class Specific Drivers: Zone Substation Instrument Transformers

Driver	Risk/Opportunity Description	Consequence
Health, Safety and Environment Asset Integrity	Failure of instrument transformer	Breakdown of insulation leading to fire/ porcelain explosion that will present safety and environmental issues Loss of supply to up to 10,000 customers for over three hours while switching transfer occurs

The volumes of work required and associated capital and operational expenditure ensure that the consequences identified in the table above are addressed to maintain network performance and risk. It is recommended that these are prudent and efficient, and will ensure that the long term interests of customers are maintained.

The following replacements have taken place at sub SBY:

- No.6 66kV bus CVT @ SBY;
- No.6 66kV bus ABB MVT @ SBY 2014;
- 22kV CN11 CTs 2014; and
- 66kV Conelectric CTs @ ES 2015

Table 4-45: Historical Replacements - Zone Substation Instrument Transformers

Replacement Volumes – Zone Substation Instrument Transformers		Year						
	Unit	2012	2013	2014	2015	2016	2017	2018
Zone substation instrument transformer	ea	-	-	6	3	-	-	-

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

There are no planned replacement volumes from 2019 to 2030.

Typically when instrument transformers are retired and not required/suitable as spares, they are taken to Tullamarine depot and kept in the bunded area. They are then collected by Sims Metal who is responsible for testing the oil for contamination and disposing of it accordingly.

4.4.9.9 Future Improvements

CTs carrying normal and fault currents and VTs are subject to multiple temporary over voltages. Instrument transformer insulation systems are a small volume within an insulated housing. Therefore this design inherently has high electrical stresses and requires the insulation to be high quality without any contamination to achieve a long life. Catastrophic failures have occurred in the wider electricity supply industry. Porcelain was previously specified for all 66kV instrument transformers, but has since been revised to polymeric housings to further reduce the consequences of shattering porcelain during a failure.

The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information on instrument transformers and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

The industry has experienced failures of younger types of instrument transformers and as a result a rigorous testing program has become necessary. The entire condition based testing program is to be reviewed and consideration to test younger instrument transformers is recommended. SAP maintenance plans need to be created once a new testing interval has been established.

4.4.10 INFORMATION

Jemena's AMS provides a hierarchical approach to understanding the information requirement to achieve Jemena's business objectives at the Asset Class. In summary, the combination of Jemena's Business Plan, the individual Asset Business Strategy (ABS) and Asset Class Strategy (ACS) all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives Table 4-46. Table 4-47 identifies the current and future information requirements to support the Sub Asset Class critical decisions and their value to the Asset Class. Table 4-48 provides the information initiatives required to provide the future information requirements identified in Table 4-47. Included within this table is the risk to the Sub Asset Class from not completing the initiative.

All of the information required by the transformer Sub Asset Class is available within Jemena's current business systems.

Table 4-46: Instrument Transformer Business Objectives and Information Requirements

Business Objective	Jemena Information Sources	Externally Sourced Data
Maintain Safety, availability and reliability of Instrument Transformers	SAP DrawBridge Condition/maintenance reports Daily situation reports Standard Maintenance Instruction (SMI) ECMS	VESI primary plant committee. Alerts – from DB's and Government Organisations and manufacturers. Manufacturing manuals. AS/IEC standards.

Table 4-47: Instrument Transformer Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Instrument Transformer - Asset Creation	Specifications and tender responses Zone Substation Primary Design Standard		High: Regulated to maintain supply reliability, safety and quality of supply. Also

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	New asset project progress reporting. Completion recorded in SAP Asset register in SAP		a Competitive price structure and compliance to performance specifications requirements

Maintain functionality of Instrument Transformers via Inspections and audits	Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• Basic specification
	  ○ Voltage
	  ○ Current
	• Location: Zone substation name
	• Address
	Condition Monitoring
	Maintenance reports & Test reports
	Performance history:
	• Daily situation reports
	• Investigation reports (ECMS)
	• Plant defect reports
	DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts
	SMI's – (Standard maintenance instruction) located on Jemena's Intranet
	SAP notifications and work orders activities performed and components replaced
	Details of work completed recorded in SAP
		Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.
		Photograph Instrument transformer nameplate and attach to SAP equipment.
		Access all information via electronic tablet in the field.
		Update asset data in SAP for missing data.
			High: Regulated to maintain supply reliability, safety and quality of supply

Maintain functionality of Instrument Transformers via Preventive Maintenance	Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. Scheduled task description, timing and completion recorded in SAP; SMIs held in Sharepoint, Policies & Forms. Manufacturers maintenance manuals SAP notifications and work orders activities performed and components replaced.	Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	**Current Information Usage**	**Future Information Requirement**	**Value to Asset Class (High, Medium, Low with justification)**
	Details of work completed recorded in SAP Details of spare equipment located in SAP OPEX & CAPEX cost reporting recorded in SAP	documents to be scanned and stored in Drawbridge. Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	
Maintain functionality of Instrument Transformers via Condition Monitoring	Condition monitoring tasks, schedule in SAP and results stored in proprietary test equipment data base, in SAP Scheduled task description, timing and completion recorded in SAP. Outputs from condition monitoring analysis	Migrate Condition & Performance reports/data into SAP to improve analysis and decision making.	High: Regulated to maintain supply reliability, safety and quality of supply

Respond to Instrument Transformer defects / faults to restore equipment operationally.
Perform corrective maintenance.
	Alerted via JEN Control Room or situation report.
	Asset register SAP, with details of each asset and significant components;
	• Manufacturer
	• Type
	• Equipment description
	• Construction year
	• basic specification
	  ○ Voltage
	  ○ Current
	• Location: Zone substation name
	• Address
	SAP notifications and work orders activities performed and components replaced.
	Details of work completed recorded in SAP
	Condition Monitoring
	Maintenance reports & Test reports
	Performance history:
	• Daily situation reports
	• Investigation reports (ECMS)
	• Plant defect reports
	DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts
	Asset failure details and investigation reports. Stored in ECMS
		Although hard copies of manufacturers manuals (where available) are stored in Collins Street Melbourne compactus, all documents should be made available in in Drawbridge. Manufactures manuals for older assets may not be available.
		Access all information via electronic tablet in the field.
		All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.
			High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	**Current Information Usage**	**Future Information Requirement**	**Value to Asset Class (High, Medium, Low with justification)**
	Details of spare equipment located in SAP Opex & CAPEX cost reporting recorded in SAP		
Asset Class Strategy Review	Condition data Fault/failure data Maintenance & replacement costs AMS		Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-48: Instrument Transformer Critical Decisions Business Information Requirements

Information Initiative	**Use Case Description**	**Asset Class Risk in not Completing**	**Data Quality Requirement**
Migrate Condition & Performance reports/data into SAP Photograph instrument transformer nameplate and attach to SAP equipment Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	To improve analysis and decision making. Asset data available from business systems saving on site trips.	Poor efficiency in accessing asset data	Asset Data as per RCM and SAP requirements.

4.5 ZONE SUBSTATION CAPACITOR BANKS

4.5.1 INTRODUCTION

The Zone Substation asset sub-class strategy applies to capacitor banks installed in zone substations and includes the capacitor cans, the inrush current limiting reactors, the current transformers and earth switches within the capacitor bank enclosures

The Zone Substation Capacitor Banks Asset Sub-Class Strategy (**ACS**) provides an asset overview, while identifying the best strategies and plans for managing assets over their lifecycles.

The ACS is based on key information about each asset (including risk, performance, capital expenditure and operational expenditure). Based on this information, the asset class strategy provides details about the Jemena Electricity Network's (**JEN**) capacitor banks and comprises five key areas:

- **Asset class profile** includes information about the type, specifications, life expectancy and age profile of capacitor banks in service across the JEN.
- **Asset strategy** outlines capacitor banks asset management practices. This includes key capacitor bank strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and programs of work. See Section 7.1.4 Life Cycle Management.
- **Asset risk** includes information about asset risk, including causes and consequences. See Section 7.1.2 Risk.
- **Asset performance** provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with capacitor bank management. See Section 7.1.3 Performance.
- **Asset expenditure assessment** provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

This section includes information about the type and specifications of the capacitor banks in service across the Jemena Electricity Network (**JEN**).

Installation of capacitor banks in zone substations is found to be a very economical way to increase the utilisation of station assets, defer capital expenditure by optimising the available capacity of the network, and to provide voltage support particularly within industrial supply areas and periods of high load demand during summer and winter.

Capacitor banks vary in size from 4MVAR to 12MVAR and a fully loaded zone substation can have a maximum of 36MVAR (3 x 12MVAR) reactive capacity. They are time or VAR controlled, automatically or manual switched and help reduce:

- avoidable sub-transmission losses caused by reactive load current; and
- KVA demand on the zone substation transformation capacity

Capacitors can be categorised as follows:

- By construction: the large Ducon type with rated capacities from 388 kVAR to 888 kVAR and the smaller, modern rectangular cans rated from 100 kVAR to 373 kVAR;
- By fuse design: externally fused cans and internally fused cans; and
- By connection: series and parallel combinations

4.5.1.1 Asset Specification

Table 4-49 lists each zone substation capacitor banks location, manufacturer and year of manufacture

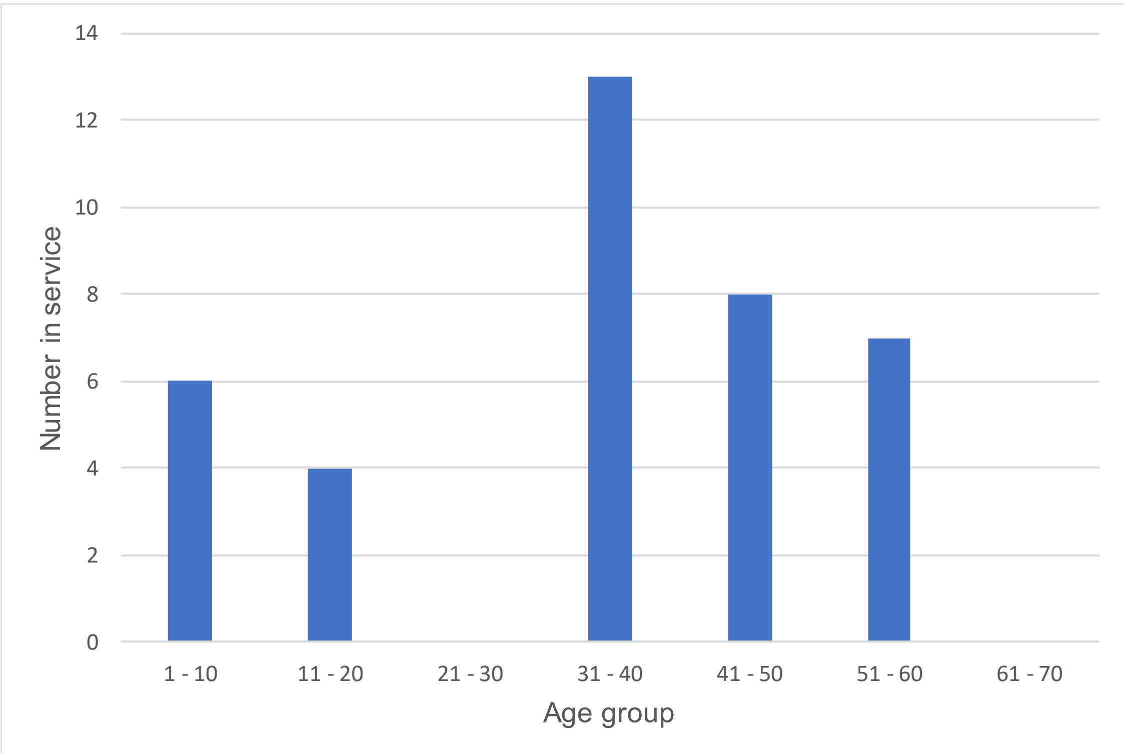
Table 4-49: Capacitor Bank Information

No.	Description	ZSS	Year Made	Age	Manufacturer	I – Indoor O – Outdoor
1	NO.1 CAP BANK	AW	1966	52	DUCON	O
2	NO.3 CAP BANK	AW	1981	37	TYREE	O
3	NO.2 CAP BANK	BD	1968	50	ASEA	I
4	NO.3 CAP BANK	BD	1962	56	NISSIN/DUCON	O
5	NO.1 CAP BANK	BMS	2014	4	ABB	O
6	NO.1 CAP BANK	CN	1970	48	COOPER	I
7	NO.2 CAP BANK	CN	1967	51	DUCON	O
8	NO.3 CAP BANK	CN	1986	32	ASEA	O
9	NO.1 CAP BANK	COO	2007	11	AMP CONTROL	O
10	NO.2 CAP BANK	CS	1976	42	ASEA	O
11	NO.1 CAP BANK	EP	1967	51	DUCON	I
12	NO.6 CAP BANK	EP	1978	40	DUCON	I
13	NO.3 CAP BANK M1	EPN	2015	3	ABB	I
14	NO.3 CAP BANK M2	EPN	2015	3	ABB	I
15	NO.1 CAP BANK	ES	1965	53	DUCON	O
16	NO.2A CAP BANK	FE	1981	37	ASEA	O
17	NO.2B CAP BANK	FE	1981	37	ASEA	O
18	NO.1 CAP BANK	FF	1976	42	COOPER	O
19	NO.1A CAP BANK	FW	1966	52	ASEA	O
20	NO.1B CAP BANK	FW	1981	37	ASEA	O
21	NO.3A CAP BANK	FW	1978	40	ASEA	O
22	NO.3B CAP BANK	FW	1982	36	ASEA	O
23	NO.1 CAP BANK	FT	1970	48	ASEA	I
24	NO.2 CAP BANK	FT	1980	38	ASEA	I
26	NO.1 CAP BANK	NT	2000	18	ABB	I
27	NO.1 CAP BANK	NH	1986	32	ASEA	I

No.	Description	ZSS	Year Made	Age	Manufacturer	I – Indoor O – Outdoor
28	NO.2 CAP BANK	NH	1988	30	ASEA	I
30	NO.2A CAP BANK	PV	2013	5	ABB	O
31	NO.2B CAP BANK	PV	2013	5	ABB	O
32	NO.1 CAP BANK	SBY	1978	40	COOPER	O
33	NO.1 CAP BANK	SHM	2007	11	ABB	O
34	NO.1 CAP BANK	ST	1986	32	ASEA	I
35	NO.2 CAP BANK	ST	1985	33	ERO STRANSTROM	I
36	NO.1 CAP BANK	TH	1986	32	ASEA	O
37	NO.2 CAP BANK	TH	1986	32	ASEA	O
38	NO.1 CAP BANK	TMA	2014	4	ABB	O

Figure 4–26 shows the current capacitor banks' age profile (the number of capacitor banks installed by year of manufacture: 38).

Figure 4–26: Capacitor Bank Age Profile



Jemena capacitor banks design life expectancy is approximately 50 years. Small capacitor cans have a reduced design life of. The plan is to replace capacitor banks only when they reach the end of their average lives based on condition. The consequence of a capacitor bank failure is low.

A capacitor bank's life expectancy depends on the life and quality of its insulation system, its build quality and its installation location, i.e. indoor or outdoor (those installed outdoor are more susceptible to vermin and moisture ingress and accumulation of pollution).

4.5.2 RISK

This chapter includes information about capacitor bank risk profiles involving the way that asset class criticality is established, the risks posed by capacitor bank failures (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 capacitor banks.

This information specifically involves:

- Asset class criticality score (sub asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Existing controls ;
- Asset Spares;
- Contingency;
- Future risks (involving other potential risk issues currently being managed).

Capacitor banks are generally reliable and the risk of failure is considered to be low. The major risks associated with capacitors are environmental, with respect to potential failures leading to oil spills.

Emerging risks for this asset class include:

- Ageing population of all component parts including CTs, VTs, reactors, earthing switches and cans;
- Deteriorating interior capacitor can insulation condition of fluid/oil/paper insulation system due to heat and electrical stress by being in-service;
- Corrosion of capacitor can enclosures resulting in fluid/oil leakage and soil contamination, particularly with large Ducon units;
- Expenditure prioritisation restricting timely replacement.

4.5.2.1 Criticality

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub asset class level by following the Asset Criticality Assessment Procedure (JEM AM PR 0016). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of Jemena'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 capacitor banks has an asset criticality score of AC1 (low) due to possible regulatory enquiry.

Zone substation capacitor banks are low criticality, low volume assets. They are installed in zone substations to reduce system losses, maximise asset utilisation and to provide reactive power compensation for heavy load conditions. The capacitor banks vary in size from 4 MVAR to 12 MVAR and they are time or VAR controlled, automatically or manual switched. Zone Substations can operate successfully without capacitor banks in service, however transformation capacity may be limited at times of heavy loading.

4.5.2.2 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 Critical Spares Assessment Procedure (JEM AM PR 0015). It was determined that adequate capacitor bank component spares are maintained at Tullamarine depot and stock holdings are managed by the Services & Projects team.

Critical Spares Assessment Procedure (JEM AM PR 0015) was used as one of a number of tools to conduct economic assessment for holding spares. Refer to Appendix I

Furthermore when assets are retired from service consideration is given to retaining components or entire asset as spares to service existing aging fleet.

Limited spare capacitors are located within the Tullamarine store and AW zone substation storage area. They are suitable replacements for small capacitors cans at various zone substations. As small capacitor cans are depleted, new spares are purchased.

Limited spare capacitors are located within the Tullamarine store and AW zone substation storage area. They are suitable replacements for capacitors cans at various zone substations. As capacitor cans are depleted, new spares are purchased.

4.5.2.3 Existing Controls

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 7.1.4.2, together with initiation of replacement projects for assets determined to in danger of major failure.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the failed capacitor bank/components. Once determined, either components are replaced from stock or whole bank is retired and a replacement project actioned.

4.5.3 PERFORMANCE FACTORS

This chapter includes information about asset performance measures. Asset performance measures for Jemena zone substation capacitor banks are designed to achieve a high level of reliability by undertaking a practical, cost effective program of preventive & corrective maintenance, coupled with planned, economic replacement of capacitor banks before failure; to maintain quality of supply, mitigate the safety risk to personnel.

SAP records the failures and repairs performed on capacitor banks. This data is used as an indicator of performance. Over the last 5 years, there has been an average of 16 defects/failures per year

Specific capacitor bank operating measures (and condition monitoring) include the following:

- Condition monitoring tests: partial discharge and thermography; and
- On-line, non-disruptive monitoring surveys: Ultrasonic and UHF detection for air borne partial discharge signals

Performance requirements and targets;

- Failure Prevention – avoiding catastrophic (unplanned outage more than 24 hours) capacitor bank failures from occurring within zone substations.- target **zero** pa.

- SAP records the failures and repairs performed on capacitor banks. This data is used as an indicator of performance. Over the last 5 years, there has been an average of 16 defects/failures per year. Based on the history of capacitor unit replacements, defect replacement of 6 capacitor cans per annum is expected.

4.5.3.1 Assessment

A number of factors are assessed to determine if individual assets of the capacitor bank group have a high probability that the unit will continue to reliably perform its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and analysis of actual performance are examined.

SAP records indicate over the last 5 years, there has been an average of 16 defects/failures per year

4.5.3.2 Condition Assessment

- All known (at the time) Polychlorinated Biphenyls (PCB) insulated capacitors were replaced in 2000. PCB's were used as an insulating liquid in electrical systems over a number of years, particularly in capacitors. PCBs create an environmental risk and are carcinogenic when burnt at low temperatures.

  PCB contamination is defined as "scheduled" (>50 parts per million and 50g PCB) or "non-scheduled" (>2 and <50 parts per million). Most high voltage capacitors on the network are known to be PCB free, however there is a small number of capacitor cans referred to as large Ducon types and small capacitor cans which may contain PCB at levels greater than 50ppm. Recent disposal of some of these capacitors has confirmed they were contaminated; however the sampling process is destructive.

  At ST zone substation some retired capacitor cans were found to be highly contaminated with PCBs. These cans were initially assessed to have >2 and <50 parts per million of PCBs. However, oil tests after they were decommissioned indicated very high levels of PCBs. Other distribution businesses within Victoria have experienced similar issues with these cap cans.

- Series reactors installed within the No.3 capacitor bank at CN were found to be defective due to severe cracks appearing in the epoxy resin body. The nature of the defect has affected the integrity of the epoxy resin which encapsulates reactors to restrain winding movement when energising the capacitor bank or during fault conditions. The reactors have since been replaced. This type of defect is monitored during monthly zone substation inspection.

- Some capacitor can families are suffering increasing failure rates. As these are identified they will be programmed for replacement.

- There was a history of the ST zone substation No.2 capacitor bank tripping on current balance over several years. This had been occurring regularly and field crews were required to attend site and rebalance the entire capacitor bank, which involved the disconnection of each capacitor unit for testing. This exercise was time consuming and physically demanding and a waste of valuable resource time. The problem was related to a particular type of old capacitor cans. That is the ESTA PHFPF06.73 type cans and these were all replaced in 2009 with ABB CHD480B. During 2011, the disposal process began and oil samples for the capacitor cans have been found to contain PCB, even though the capacitor cans were labelled PCB free. All Capacitor cans fitted with PCB free labels shall have the labels removed, and all capacitor can oil leaks are to be treated as PCB contaminated unless proven otherwise.

- The new No.1 capacitor bank at PV commissioned in 2011 was producing a noticeable noise level as compared to a similar unit at SHM. The project manager was made aware of the issue and the issues were addressed in liaison with the manufacturer ABB.

- Capacitor unit spares will be assessed and stock levels adjusted accordingly. During 2011, 6 spare capacitor cans were purchased for CN, NH, ST. During 2012, 4 spare capacitor cans were purchased for FT and NH.
- Fuses on the capacitor cans at FF and FT have been operating. These fuses were under rated and have been subsequently replaced at FF. An assessment of the fuse rating for both capacitor banks at FT was undertaken and it was identified that the problem was with the fuse holders. This was rectified; however, the issue will be monitored
- Leaking cans were discovered on the No.1 capacitor bank at CN in November 2013. Extra cans were ordered from ABB to replace the leaking cans. The No.1 capacitor bank was returned to service in February 2014.
- A leaking Ducon cap unit was discovered on the No.1 capacitor bank at ES in 2017. PCB 3ppm. An assessment of the oil leak will be continued in 2018. Spare replacement has been identified if required.

4.5.3.3 Utilisation

Capacitor banks installed across Jemena zone substations are time or VAR controlled, automatically or manual switched. They help manage kVA demand on the zone substation transformation capacity.

Many capacitor banks have been switched off at the request of AEMO, as transmission voltages were too high due to reduced loading and changes in generation (reduced Var consumption) with retirement of Hazelwood Power Station. (Long transmission lines act as capacitors when loading is low).

4.5.3.4 Control Effectiveness

Controls employed (inspection, condition monitoring & maintenance) and condition based replacements completed are identified below. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table:

Table 4-50: Controls Effectiveness

Risk Category	Cause/incident	Controls	Incidents in past 5 years
Health, Safety & environment	Capacitor bank or cans failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed	Nil
Regulatory & Compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil – costs not significant, average of 16 defect/failures pa

4.5.4 LIFE CYCLE MANAGEMENT

This chapter includes information about capacitor bank asset management practices, including key capacitor bank strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset lifecycle management options;
- asset creation (including asset acquisition and asset spares);
- asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- asset replacement and disposal; and
- future improvements.

4.5.4.1 Lifecycle management options

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure

There are three feasible lifecycle management options:

- Condition monitoring and preventive maintenance with condition based replacement. Properly electrically protected and adequately maintained, a capacitor bank's life expectancy can exceed 50 years. This option is preferred as the best economic and risk based option.
- Corrective maintenance with fixed, age-based replacement at its nominal life of 40 years, (irrespective of condition). This option is not considered to be cost-effective, as assets in good condition (based on historical performance and defects) will be replaced prematurely. Condition monitoring and preventive maintenance can be employed to maximise asset life, and asset then replaced to mitigate against safety and reduced reliability risks.
- Corrective maintenance with run-to-failure replacement. This is not a realistic option due to the criticality of the assets, the impact on health and safety, impact on supply reliability and the long lead-time for replacement. The risk to the network due to long lead times when procuring replacement assets can be mitigated by purchasing spares.

4.5.4.2 Creation

New capacitor banks are installed if the Customer & System Planning team deem the need and necessity for VAR compensation at zone substations across JEN

Capacitor banks are typically purchased under a period contract in alignment with primary plant manual and specification requirements. Incorporation of the elements of this document, particularly opportunities for future improvements, will determine requirements of plant specification.

4.5.4.3 Asset Operation and Maintenance

This section provides information about the current asset maintenance program for Capacitor Banks.

The current asset maintenance program involves:

- Monthly inspection conducted by operational employees
- Annual Inspection conducted by engineering staff;

- reactive and corrective maintenance;
- preventive maintenance; and
- condition-based monitoring

Inspections of capacitor banks shall be performed monthly by operators as part of the zone substation inspection program. In addition capacitor banks will be viewed as part of the annual zone substation engineering audit.

Whenever access to the capacitor bank is required for repairs, the opportunity shall be used to inspect the entire installation. These inspections shall include the capacitor cans, inrush current limiting reactors, and current transformers for any of the following:

- signs of tracking or cracks on insulators;
- tracking, cracking or damaged inrush reactors;
- blown external fuses;
- integrity of all lead connections to equipment;
- if fitted, bird and animal covers on bushings are in place and have not perished; and
- leakage of insulating fluid or any sign of capacitor container swelling

Inspection of HV connections is important because some indoor capacitor banks cannot be readily scanned with an infrared camera.

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified defects (or both), resulting in the repair.

Corrective maintenance is performed to repair defects identified during in-service inspection or routine maintenance and by thermal surveys.

1. Faults: Immediate response required to investigate and may include some corrective action
2. Defects: Following a fault investigation, there may be some further correction action that is planned in the future.

Causes of failures are:

- animal and bird interference, causing external flashover between phases or to earth structures and tracking on insulator surfaces;
- lightning;
- high resistance connections;
- ageing of dielectric material in capacitor elements;
- moisture ingress and corrosion; and
- harmonics leading to overheated capacitor cans

Capacitor bank failure mode can include:

- external fuse fatigue;
- fails to carry load; and
- fails to insulate

Capacitor can faults are detected by current balance or voltage balance protection schemes in addition to conventional over current and earth fault protection schemes. Fuses and connections of capacitor cans can be repaired or replaced but repair of the actual capacitors is neither economical nor practical. The faulty capacitors are normally replaced and the banks are re-balanced.

The preventive maintenance program shall consist of:

- Maintenance of indoor capacitor banks and their earth switches is scheduled on a 6 yearly cycle. There are 5 indoor cap banks;
- Maintenance of cubicle type capacitor banks and the NT capacitor bank including their earth switches is scheduled on a 4 yearly cycle. There are 3 cubicle type cap banks;
- Maintenance of all outdoor capacitor bank and their earth switches is scheduled on a 6 yearly cycle. There are 28 outdoor cap banks

The capacitor cans, reactors, and current transformers are largely maintenance free items and therefore in the past were not scheduled for routine planned maintenance. This was an outcome of a previous RCM assessment. Maintenance was planned to be reactive based on the condition of the plant as detected by inspections, operations and condition monitoring.

The maintenance of indoor and more recently outdoor capacitor banks has been reviewed and reintroduced for the following reasons. This mainly focuses on cleaning the enclosure, floors, and porcelain surfaces, inspection of HV connections and maintenance of exhaust fans (where applicable) and the earth switch. Inspection of HV connections is important because some indoor capacitor banks cannot be readily scanned with an infrared camera. The capacitor bank earth switches are permanently installed safety devices which can develop high resistance connections over time. Maintenance is necessary to ensure continued functionality. Outdoor capacitor bank enclosure condition and removal of debris is the main driver.

Maintenance of indoor capacitor banks and enclosures is deemed necessary because of the accumulation of dust and debris within the enclosure that under normal circumstance would not be washed down by rain. The accumulation of dust will eventually impact on the dielectric strength of insulating surfaces, which could potentially lead to external tracking and a flashover. The level of dust could also present a health concern to personnel working within the enclosure.

The capacitor bank earth switches are permanently installed safety devices which can develop high resistance connections over time. Maintenance is necessary to ensure continued functionality.

Preventive maintenance of the capacitor installations and earth switches should be co-ordinated with the capacitor bank circuit breaker maintenance where possible.

4.5.4.4 Condition-based monitoring

Infra-red thermographic surveys covering all HV plant such as capacitor banks are also included in the annual thermal surveys. Not all capacitor banks components are directly are directly visible due to their design. It is not normally possible to detect a thermal defect for modular or indoor capacitor bank using a thermal camera.

4.5.4.5 Asset Replacement/Disposal

There are 35 capacitor banks of various capacities installed across the JEN network. The large mineral oil filled capacitor can (Ducon unit) are reliable and there have been no known catastrophic failures. However there have been some capacitor cans which had developed oil leaks and one capacitor can from the EP No.3 capacitor bank was replaced.

The Ducon bulk oil capacitor cans cannot be repaired and the only option is to replace with a spare. While there are spares available for some of the Ducon bulk oil capacitor cans, as of 2018, there are no type OF7881 spare cap cans available for a total population of 24 cap cans of similar make and model across the Jemena Electricity Network. In the event of a failure of these capacitor cans, the only option may be to replace the capacitor bank. This will be assessed when the failure occurs. In some circumstances, the replacement of a large Ducon capacitor can will be assessed for replacement with a modern capacitor can.

From 2008 through to 2014 forty one capacitor unit failures and replacements have been recorded. Based on the history of capacitor unit replacements, defect replacement of 6 capacitor cans per annum is expected.

Table 4-51: Historical replacements -Zone Substation Capacitor Banks

Replacement Volumes – Zone Substation Capacitor Banks	Unit	Year						
		2012	2013	2014	2015	2016	2017	2018
Replace Ducon capacitor bank	ea	-	1	-	-	-	-	-
Replace capacitor cans	ea	-	8	-	-	3	4	-

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

Table 4-52 lists the forecast CAPEX replacement volumes for zone substation capacitor banks from 2019 to 2023, based on these drivers.

Table 4-52: Forecast Replacement Volumes - Zone Substation Capacitor Banks

Replacement Volumes – Zone Substation Capacitor Banks	Unit	Year											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Replace Ducon capacitor bank	ea	-	1	-	-	-	-	1	-	-	-	-	1
Replace capacitor cans	ea	6	6	6	6	6	6	6	6	6	6	6	6

(1) This table does not include the volume of installations planned that are classified as augmentation works.

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how Jemena prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-53 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure.

Table 4-53: Specific Drivers - Zone Substation Capacitor Bank Replacements

Driver	Risk/Opportunity Description	Consequence	Driver
Asset Integrity Regulatory Compliance	Equipment failure/frequent loss of asset integrity	Regulatory non-conformance and caused by issues with power factor correction	Asset Integrity Regulatory Compliance

Driver	Risk/Opportunity Description	Consequence	Driver
Asset Integrity Health, Safety, and Environment	Equipment failure	Capacitor bank may explode, and porcelain/other fragments may be expelled at the risk of employee safety	Asset Integrity Health, Safety, and Environment
Health, Safety and Environment	There are a number of capacitor cans referred to as large Ducon types that may contain high Polychlorinated Biphenyls (PCB) levels (>50 ppm). PCB's were used as an insulating liquid in electrical systems over a number of years, particularly in capacitors.	PCBs create an environmental risk and are carcinogenic in nature.	Health, Safety and Environment

The volumes of work required and associated capital and operational expenditure ensure that the consequences identified in the table above are addressed to maintain network performance and risk. It is recommended that these are prudent and efficient, and will ensure that the long term interests of customers are maintained.

Typically, when capacitor cans are retired or replaced, they are drained of oil, which is tested and disposed of separately. In order for the capacitor cans to be fit for transportation, a certificate must be obtained to ensure the capacitor can is free of PCBs so it can be appropriately transported.

4.5.4.6 Future Improvements

The Victorian Electricity Supply Industry Group Meeting allows sharing of defect information on capacitors and other primary plant. The committee members work to share and improve maintenance and replacement knowledge and promote efficiency and reliability of substation management.

4.5.5 INFORMATION

Jemena's AMS provides a hierarchical approach to understanding the information required to achieve Jemena's business objectives at the Asset Class. In summary, the combination of Jemena's Business Plan, the individual Asset Business Strategy (ABS) and Asset Class Strategy (ACS) all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives Table 4-54. Table 4-55 identifies the current and future information requirements to support the Sub Asset Class critical decisions and their value to the Asset Class. Table 4-56 provides the information initiatives required to provide the future information requirements identified in Table 4-55. Included within this table is the risk to the Sub Asset Class from not completing the initiative.

All of the information required by the transformer Sub Asset Class is available within Jemena's current business systems.

Table 4-54: Capacitor Bank Business Objectives and Information Requirements

Business Objective	Jemena Information Sources	Externally Sourced Data
Maintain Safety, availability and	SAP DrawBridge Condition/maintenance reports Daily situation reports	VESI primary plant committee. Alerts – from DB's and Government Organisations and manufacturers.

Business Objective	Jemena Information Sources	Externally Sourced Data
reliability of Capacitor Banks	Standard Maintenance Instruction (SMI) ECMS	Manufacturing manuals. AS/IEC standards.

Table 4-55: Capacitor Bank Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Capacitor Bank - Asset Creation	Specifications and tender responses Zone Substation Primary Design Standard New asset project progress reporting. Completion recorded in SAP Asset register in SAP		High: Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of Capacitor Banks via Inspections, and audits	Asset register SAP, with details of each asset and significant components; • Manufacturer • Type • Equipment description • Construction year • Basic specification • Location: Zone substation name • Address SAP Maintenance reports Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports. DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts SMI's – (Standard maintenance instruction) SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP	Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	High: Regulated to maintain supply reliability, safety and quality of supply
Maintain functionality of Capacitor Banks via Preventive Maintenance	Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. Scheduled task description, timing and completion recorded in SAP; SMIs held in Sharepoint, Policies & Forms. Manufacturers maintenance manuals SAP notifications and work orders activities performed and components replaced.	Results are recorded in SAP and standard job report (fitters report) scanned and stored on the shared network folder. All maintenance reports to be attached to the	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	Details of work completed recorded in SAP Details of spare equipment located in SAP OPEX & CAPEX cost reporting recorded in SAP	relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	
Asset Class Strategy Review	Condition data Fault/failure data Maintenance & replacement costs AMS		Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-56: Capacitor Bank Critical Decisions Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Photograph instrument transformer nameplate and attach to SAP equipment Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	To improve analysis and decision making. Asset data available from business systems saving on site trips.	Poor efficiency in accessing asset data	Asset Data as per RCM and SAP requirements.

4.6 ZONE SUBSTATION BUILDINGS AND GROUNDS

4.6.1 INTRODUCTION

The Zone Substation Buildings and Grounds asset sub-class strategy applies to zone substation housing, security and grounds. It aims to ensure that zone substations are maintained so that site safety and security is maintained and that enclosures and housings remain weather proof and a reasonable standard of appearance is maintained so that the enclosed equipment is protected.

The Zone Buildings and Grounds Asset Sub-Class Strategy provides an asset overview, while identifying the best strategies and plans for managing assets over their lifecycles.

The asset class strategy is based on key information about each asset (including risk, performance, capital expenditure and operational expenditure). Based on this information, the asset class strategy provides details about the Jemena Electricity Network's (**JEN**) zone substation housing, security, and grounds and comprises five key areas:

- Asset class profile includes information about the type, specifications, life expectancy and age profile of zone substation housing in service across the JEN;
- Asset strategy outlines zone substation housing, security and grounds asset management practices. This includes key zone substation housing, security and grounds strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and programs of work. See Section 4.6.4 Life Cycle Management;
- Asset risk includes information about asset risk, including causes and consequences. See Section 4.6.2 Risk;
- Asset performance provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with zone substation housing, security and grounds management; and
- Asset expenditure assessment provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

The asset class strategy is reviewed every three years to ensure alignment with the corporate business plan, strategy and objectives and to account for any additional asset performance and risk information

This chapter includes information about the type, specifications, life expectancy and age profile of the zone substation housing and grounds in service across the Jemena Electricity Network (**JEN**).

Zone Substations house equipment that is used to transform sub-transmission voltages to distribution voltages and to act as controlling points between differing high voltage networks.

4.6.1.1 Asset Specification

There are a total of 30 Jemena sites consisting of zone substations, switching station and HV customer substations containing Jemena 66kV sub-transmission feeders and switchgear.

Each of these sites are secured with perimeter fences, locked buildings and gates. Site identification nameplates and danger HV signs are installed on the fences and authorised personnel are issued with a key to access zone substations. The security fencing at customer substations at NEI, SSS and VCO consist of standard chain wire mesh, whereas the remaining 27 zone substations fences were upgraded to welded mesh including brick and timber panels. The three customer substations have been secure and there are no historical security issues as they are located within customer operational premises.

The Jemena zone substation perimeter fences generally consist of a combination of Welded Mesh panels topped with concertina “Tiger Tape”, brick walls, or timber panels. In addition timber panels topped with barbed wire is used adjacent to residential properties.

Table 4-57 lists the population, type and age for this asset class.

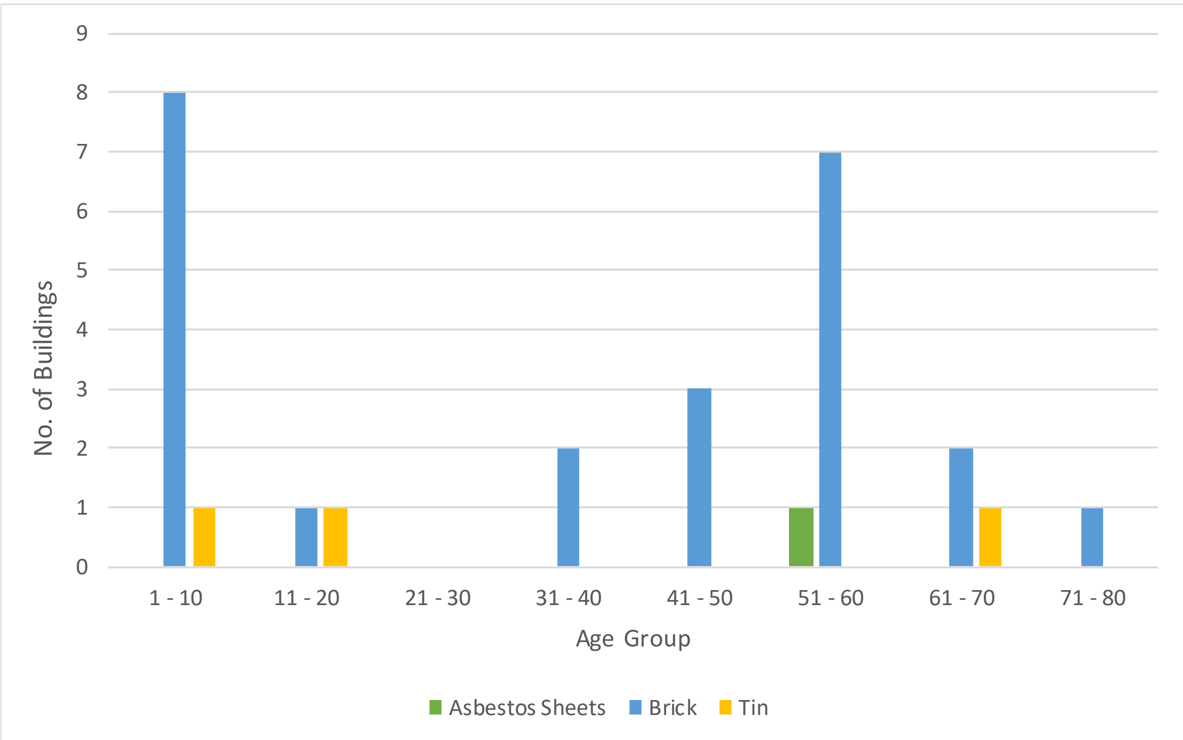
Table 4-57: Information requirements Zone Substation Buildings

Zone Substation	Building Type	Building YOM	Upgraded Security Fence	Fence YOM	Fence Material
AW (Airport West)	Brick	2017	YES	2008	Welded Mesh
BD (Broadmeadows)	Brick	2019	YES	2008	Welded Mesh
BMS (Broadmeadows South)	Brick	2014	YES	2014	Weld Mesh/Timber
BY (Braybrook)	Brick	1950	YES	2011/1998	Brick/Timber
CN (Coburg North)	Brick	1967	YES	2008	Welded Mesh
COO (Coolaroo)	Tin	2007	YES	2007	Welded Mesh
CS (Coburg South)	Brick	1976	YES	2010	Brick/Timber
EP (East Preston) A	Tin	1958	YES	2009	Welded Mesh
EP (East Preston) B	Brick	1962	YES	2009	Welded Mesh
EPN (East Preston)	Brick	2015	YES	2015	Welded Mesh
ES (Essendon)	Brick	1965	YES	2010	Brick/Timber
FE (Footscray East)	Brick	1967	YES	2010/1998	Welded Mesh/Timber
FF (Fairfield)	Brick	1950	YES	2019	Timber
FT (Flemington)	Brick	1970	YES	2010	Welded Mesh/Timber
FW (Footscray West)	Brick	1966	YES	2011	Timber
HB (Heidelberg)	Brick	1966	YES	2008	Welded Mesh
MAT (Melbourne Airport)	Tin	2015	YES	2015	Welded Mesh
NEI (Nilsen)	Cement sheet	1994	NO	Customer Owned	Chain wire Mesh
NH (North Heidelberg)	Brick	1973	YES	2010	Welded Mesh/Brick
NS (North Essendon)	Brick	1948	YES	2018	Timber
NT (Newport)	Brick	1970	YES	2009	Welded Mesh
PTN (Preston)	Brick	2019	YES	2019	Welded Mesh
PV (Pascoe Vale)	Brick	2011	YES	2010	Timber
SBY (Sunbury)	Brick	2018	YES	2008	Welded Mesh

Zone Substation	Building Type	Building YOM	Upgraded Security Fence	Fence YOM	Fence Material
SHM (Sydenham)	Brick	2008	YES	2008	Welded Mesh
SSS (Somerton Switching Station)	Tin	2001	NO	2001	Chair wire Mesh
ST (Somerton)	Brick	1985	YES	2009	Welded Mesh
TH (Tottenham)	Brick	1984	YES	2008	Welded Mesh
VCO (Visy Board Coolaroo)	Brick	Customer's	NO	Customer Owned	Chair wire Mesh
TMA (Tullamarine)	Brick	2015	YES	2015	Welded Mesh
YVE (Yarraville)	Brick	2013	YES	2013	Welded Mesh

Figure 4–27 shows the current zone substation building age profile.

Figure 4–27: Zone Substation Building Age Profile



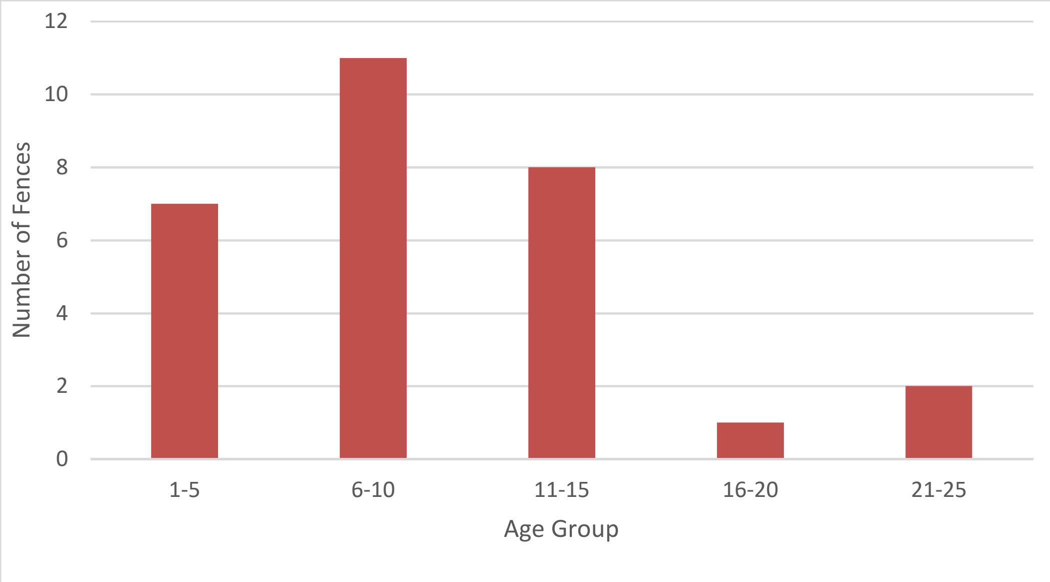
It can be seen 11 buildings are over 50 years old and 15 are over 40 years old; which indicates considerable investment in building replacement in future years.

The nominal life of zone substation buildings is 50 years for timber and 90 years for masonry type buildings.

The life expectancy of the zone substation buildings depends on the quality of materials used in construction, presence of asbestos and the outcome of civil engineering audits.

Figure 4–29 shows the current zone substation fence age profile.

Figure 4–29: Zone Substation Fence Age Profile



It can be seen that 2 zone substation fences (Timber fence facing residential homes) are over 20 years old and their condition indicated that replacement will be planned.

The nominal life of timber zone substation fences approximately 20 years and 40 years for the welded mesh fences.

The life expectancy of the zone substation fences depends on the quality and type of materials used in construction, such as steel posts or timber panels and posts.

4.6.2 RISK

This chapter includes information about zone substation housing, security and grounds risk profiles involving the way that asset class criticality is established, the risks posed by their 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 zone substation housing and grounds.

This information specifically involves:

- Asset class criticality score (sub asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Existing controls ;
- Asset Spares;
- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

The major risks associated with the surrounds and housings of substations are:

- Safety to employees during operation and maintenance;
- Supply reliability due to lack of access for operation;

- Equipment failure due to animals/birds/insects;
- Poor public perception due to appearance if in an unkempt state;
- Vegetation covering vent holes might result in equipment overheating;
- Public access safety risk due to unsecured doors, fences and windows;
- Access by unauthorised persons;
- Water leaking through roofs;
- Environmental oil loss; and
- Vandalism;

Failure to inspect Zone Substations and to undertake grounds, fences and housing maintenance on a regular basis, can lead to prolonged security breaches, public safety concerns, asset damage leading to mal-operation of equipment and supply reliability issues.

Emerging risks include:

- Ageing building collapse;
- Possible forced removal of asbestos containing materials;
- Environmental contamination due to inadequate or deteriorated oil containment systems; and
- Increased terrorism threats; security breaches

Greater incidents of temperature, and storm extremes and grass and bushfire threats.

4.6.2.1 Criticality

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub asset class level by following the Asset Criticality Assessment Procedure (JEM AM PR 0016). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of Jemena'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 buildings and grounds has an asset criticality score of AC4 (High) due to operational and health and safety consequences associated with unauthorised access. Also the building itself protects the internal equipment from environmental damage.

Zone substations represent critical infrastructure. Access to switch rooms and switchyards is necessary to operate the zone substations, indoor electrical equipment needs to be kept dry and Jemena has an obligation to provide a safe work place. Life extension to security systems such as gates, fences, windows and doors will form part of this asset class strategy.

4.6.2.2 Spares

It was determined that Buildings and grounds facilities are constructed of commercially available hardware and equipment; therefore any required material can be purchased from suppliers. Spares requirements for critical assets using the Critical Spares Assessment Procedure (JEM AM PR 0015) is not relevant in this case.

4.6.2.3 Failure Modes

Likely failure modes include:

- Corrosion of steel structures, fence posts, gates and wire mesh;
- Corrosion of steel roofing, gutters and downpipes;
- Water ingress due to holes in roof, blockages of roof gullies and spouting;
- Timber fencing and building weatherboards deterioration due to rotting and splitting;
- Timber building collapse due to timber rot, or termite infestation;
- Access prevention due to overgrown grass, shrubs and trees;
- Security breaches due vandalism; and
- Vermin infestation

4.6.2.4 Existing Controls

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.6.4.2, together with initiation of replacement projects for assets determined to in danger of major failure.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the assets. Once determined, temporary repairs can be actioned followed by purchase of commercial materials and installation of permanent repairs or refurbishment.

4.6.3 PEFORMANCE FACTORS

This chapter includes information about asset performance measures. Asset performance measures for Jemena substation buildings and grounds are designed to achieve a high level of reliability by undertaking a practical, cost effective program of preventive & corrective maintenance, coupled with planned, economic replacement/upgrade of substation buildings, fences and ground assets before failure; to mitigate the safety risk to personnel and contractors.

SAP records of buildings and grounds defects and repairs are available and there is no significant increase in defects and repairs over previous years. A register of break-ins is available.

4.6.3.1 Requirements

The performance objectives of zone substation buildings and grounds are to, in a cost-effective manner:

- ensure public / employee safety; reduce the risk of network outages; minimise unauthorised access; protects the internal equipment from environmental damage; and maintain the appearance of substation grounds to a standard that meets community expectations.

The performance objectives will aim to ensure that all zone substations are:

- inspected at regular intervals to ensure that these substations do not compromise public or employee safety and remain in a serviceable condition; and
- maintained so that site safety and security is maintained and that enclosures and housings remain weather proof and a reasonable standard of appearance is maintained so that the enclosed equipment is protected

Specific substation building and ground performance measures include the following:

- Monthly operator security inspection;
- Annual zone substation audits; and
- 3-yearly civil audits of all Jemena zone substation buildings, structures and foundations for HV plant, fences, and transformer sound enclosures.

4.6.3.2 Assessment

A number of factors are assessed to determine if individual assets of the buildings and grounds group have a high probability that the unit will continue to reliably perform its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and analysis of actual performance are examined. The following reports provide data for these areas:

- SAP records of building and grounds defect and repairs as a notification and PM order; and
- 3-yearly civil audit reports

4.6.3.3 Condition Assessment

This section provides information about zone substation housing and grounds, as well as general information about other potential issues.

Control Building Air Conditioning

Control buildings containing microprocessor based protection, control equipment and battery systems, are required to operate within a temperature controlled environment. A Capital Program commenced in 2011 to install thermal insulation and air-conditioning equipment in the 21 ZSS identified as requiring the cooling to ensure the reliable operation of electronic/microprocessor based equipment. This involved the installation of 2 commercial air conditioners, doors to segregate the protection room and thermal insulation. This program has now been discontinued after the installation of air conditioning at ZSS CN was determined to be cost prohibitive to install the air conditioners as a standalone project as it involved replacing the station service transformers and the LV distribution board. Now, air conditioners are installed as part of a major building upgrade project.

ZSS HB No.1 Transformer Enclosure Roof

The civil engineering report obtained in May 2012 for No.1 Transformer Enclosure Roof at ZSS HB recommends replacing the roof with a cast in-situ type roof as was done on the No.3 Transformer Enclosure. This project is scheduled and will coincide with the replacement of the 2 existing transformers. During this time, safety precautions have been put in place and the condition of the roof is monitored. The new transformers installation also includes upgraded fire/noise enclosure.

ZSS FW No.3 Transformer Enclosure Roof

The civil engineering report obtained in February 2013 for No.3 Transformer Enclosure Roof at ZSS FW recommends continue monitoring the cracks on the underside of the roof slab. Any spalling of concrete or discolouration due to corrosion of steel reinforcing will require further investigation and probable replacement of the roof. A project to replace the roof at ZSS FW will take place in financial year 2020/21 together with the switchgear replacement project .

ZSS NS Control Room Roof

The asbestos roof on the NS control room has leaked in the past onto the HV switchgear. During the transformer replacement project repairs of the roof were undertaken, however due to the condition of sections of the roof and to guarantee long term security of the station it is recommended to replace the roof. This activity will be coordinated with the relay replacement project.

ZSS YVE and SBY Rabbit Infestation

YVE and SBY both have rabbits entering the switchyards. In recent times, rabbits have eaten through control cables at SBY and resulted in a cap bank step switch operating hundreds of times and destroying itself. Regular baiting programs at YVE and SBY may be necessary to mitigate this risk. New fence and concrete plinth's have been installed which has reduced the extent of the problem.

EGOWS at ZSS AW and ZSS SHM

The Extended Gravity Oil and Water Separation (EGOWS) system at AW and SHM have been in service for several years and they both have been cleaned and maintained in 2013. In the event of a major loss of transformer oil, the EGOWS pits will contain 100% of the oil. An Operation and Maintenance policy has been prepared and maintenance plan has been created in SAP. Dead birds and debris is being blown in the EGOWS pits and they may require maintenance. The maintenance plan for the EGOWS has been initiated with a 10 years interval. A chemical treatment program has been implemented as a trial to control the growth of algae. Over time the success of the trial will be monitored and the EGOWS maintenance interval will be reassessed.

Gate Valves at ZSS AW

The Gate valves at AW were rusty and inoperable. These valves were cleaned and deemed to be serviceable. When a replacement of a valve is required, it is recommended to replace it with a superior valve that is constructed from stainless steel and has a high grade seal (i.e. Teflon).

Storm Water Entry at ZSS ST

Storm water was found entering the cable pits underneath the switchboard at ZSS ST. The conduits entering the cable pits from outside the ZSS have been sealed up to prevent future entry of storm water in the cable pits and possible corrosion of the metal clad switchgear.

Dilapidation of ZSS MAT and YVE Control Room Buildings

ZSS control room buildings at MAT and YVE in 2012 and 2014 respectively have suffered from structural damage. MAT portable control room building has evidence of rust and degradation of paint on the external cladding. YVE control room building has developed significant wall cracks in the external brickwork distorting door frames and jamming doors. An independent civil inspection report will be prepared to address the identify actions required to address the issues.

Wall cracking and foundation subsidence at FT

Some evidence existing for several year of wall cracking most likely due to foundation subsidence. A Geotechnical investigation has been conducted and remediation work is planned for 2020.

Zone Substation Security Upgrades

The Critical Infrastructure Plan and its supporting document referred to as the Security Management System, identified JEN zone substations as high-risk sites from a malicious and opportunistic perspective. In response a program to upgrade the security fences at all JEN zone substation sites has been put in place. With the exception of NEI, VCO and switching station SSS, all sub transmission sites containing JEN assets have had their fences upgraded in accordance to the ENA - 003 Guidelines for Unauthorised Access to Electricity Assets.

VCO and SSS are located in customer owned premises areas and enclosed by additional perimeter fences.

Security assessments were conducted in 2017 and indicates a need for systemic improvements in security control measures across Jemena's Zone Substations. Three areas of concern were identified:

Access Control - Any person with a blue key can enter any Zone substation in the network without detection. This presents a risk that current or former Jemena employees and / or contractors with a key can enter any site and if they have the intent, steal material or equipment and / or damage the asset. Additionally, there is no capability to restrict access to certain areas within a site or to restrict access to some sites but not others.

Site lighting - The current lighting arrangements amount to an inadequate deterrent measure for unauthorised access to the sites after dark. It also fails to aid in the detection of unauthorised access by neighbours or passing traffic. Of greater risk, is that Jemena personnel or contractors are required to enter un-lit sites when attending at night, potentially to attend to maintenance issues caused by vandalism stemming from unauthorised access to the site. Personnel may therefore be unable to assess whether other persons are on site.

Security Monitoring - The key “detect” capability is the monitoring of network function by the Control Room. Currently, there are no mechanisms to detect a possible security breach and any related service interruption prior to it occurring. Nor are there any mechanisms to determine if intruders are present at a site when Jemena personnel or contractors are responding to a callout at night. Further, due to the limitations on visibility of who is accessing sites (access control), any Jemena personnel accessing sites without legitimate reason would go undetected. The absence of a remote, real-time detection mechanism results in a higher risk being posed to the security and safety of Jemena personnel and contractors. It also significantly reduces the effective management of the integrity, function and appearance of Jemena sites by Asset Management and the Control Room.

Recommendations are included in Section 4.6.5 Future Improvements.

Zone Substation Oil Containment

The original installation of oil containment bunds in JEN Zone Substations did not include the sealing of the bunds or the complete management of oil leaks on the site. Because the bunds are not sealed chronic oil leaks can lead to contamination of the soil and ground water. A program has been developed to complete the sealing of all unsealed bunds and install triple interceptors (Humeceptors) in the drainage from the bunds to manage the small oil leaks that occur on transformers over their operational life.

The installation of Humeceptors and the sealing of existing bunds are included in the SOW for all major projects at JEN Zone Substations. In addition a proactive program has commenced that aims to address one substation per year on a priority basis where no major works are planned in the short to medium term. Zone substation BY is planned for bunding upgrade in 2021-2025.

A trial to install innovative petrochemical filter at ZSS BY and MAT is underway in 2020.

Appendix G has the bunding status for all of the JEN zone substations.

Zone Substation Control Building Roof Assessments

Condition of the control building roofs is assessed during the annual gutter and drainage inspection.

Refer to Appendix H for listing and status of control building roofs.

Installation of Handrails on Platforms & Fixed Ladders at all Zone Substations

After a slip injury from a platform access ladder an audit was conducted in early 2013 and identified zone substations that required the installation of hand rails for platforms and fixed ladders (anti slip coating was applied to the ladder rungs). The work was completed in August 2013 at the following zone substations: ES, EP, FF, NS, NT and PV.

In November 2013 the JEN HSE Committee requested that the inspection of platforms at zone substations be added to the annual zone substation audit program. The decision was made by the Primary Plant group to extend the audit to platforms, ladders, stairs and handrails, and accelerate the audit process. By March 2014, all zone substations had been audited to the requirements of Australian Standard AS1657-2013 which covers the design, construction and installation of platforms, ladders, stairs & handrails. A report was completed and corrective action taken.

Building windows at NH and CS are showing signs of severe corrosion. Windows at FT are severely warped. All windows will be assessed and a project prepared for replacement

Building window latches were installed for pressure venting in the event of a catastrophic HV fault. The latches lose their tension and the windows drift open. Although this is not an immediate safety concern, these windows should remain closed to prevent vermin and rain and debris from entering. All windows will be assessed and the latches adjusted or renewed.

ZSS switchyard aggregate is perceived to be a possible trip hazard for employees. Although no evidence is available to substantiate this, ongoing assessment may be required in the future.

New building designs are being evaluated to determine the required ground height or basement depths for access to install HV and LV cables. This issue was identified from the HSE committee.

There is potential for unauthorised and aided access to some ZSS. Modification to personnel gates made from welded wire mesh, is taking place to prevent the gates from being opened using fencing wire. Although this is a low risk, the precautions are being implemented due to the potential consequence of a security breach. A list of all affected sites below will track the implementation of the security measure.

Completed: AW, BD, CN, EPN, EP, FT, HB, MAT, NS, TH, BMS, COO, SHM, YVE and PV

Outstanding: FE, ES, NT, SBY, TH and TMA

It is proposed to review the door handles on the external doors of all JEN zone subs to prevent unauthorized access to zone substations.

4.6.3.4 Utilisation

The utilisation of these assets relates to the installation of primary plant/equipment and secondary equipment within buildings. The building assets are fully utilised in the majority of the zone substations and any plant/equipment additions would require the extension of the buildings. However any modification, change or expansion is assessed on a case by case basis. All new zone substation buildings are designed for the final ultimate arrangement as per the system design requirements.

4.6.3.5 Control Effectiveness

Controls employed (inspection, condition monitoring & maintenance) and condition based replacements completed are identified below. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table:

Table 4-58: Controls Effectiveness

Risk Category	Cause/incident	Controls	Incidents in past 5 years
Health, Safety & environment	Buildings, fences and civil assets failure – people safety and or environment impact	Asset Management strategy applied. Replacement projects completed	Many break-ins; register is available.
Regulatory & Compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil

Risk Category	Cause/incident	Controls	Incidents in past 5 years
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

4.6.4 LIFE CYCLE MANAGEMENT

This chapter includes information about zone substation housing, security and grounds asset management practices, including key zone substation housing, security and grounds strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- asset lifecycle management options;
- asset creation (including asset acquisition);
- asset maintenance (involving inspection, reactive and corrective maintenance and preventive maintenance);
- asset replacement and disposal; and
- future improvements

4.6.4.1 Lifecycle management options

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure.

There are three lifecycle management options:

- Preventive maintenance with condition triggered refurbishment or replacement. Properly maintained buildings and housings will ensure that they are structurally safe and will last at least as long as the assets installed inside them;
- Reactive maintenance with fixed, age-based replacement (irrespective of condition). This option is not considered to be cost-effective, as preventive maintenance can be employed to defer capital replacement; and
- Reactive maintenance with run-to-failure replacement. This is not a realistic option as the zone substation buildings house vital electricity distribution assets. This option can also pose severe health and safety risks to the Jemena employees and contractors attending these sites.

The preferred asset lifecycle management option involves preventive maintenance, with the aim of achieving a life of 50 years for timber and 90 years for masonry type zone substation buildings. The replacement or major refurbishment of zone substation buildings will be triggered by the need to replace protection and control equipment, not by the age of the buildings alone. Civil and structural inspections of the buildings will indicate the need for repairs or refurbishment.

The issue of asbestos within these building remains a potential health and safety risk. The selection criteria for replacement or major refurbishment of zone substation buildings may be governed by legislation changes in the future, requiring the safe removal of all asbestos within specified timeframes.

4.6.4.2 Creation

The need for new buildings and the extension of the existing buildings or the procurement of new land is decided upon by the Network Capacity Planning and Development team in line with the growth forecasts. In addition to this new zone substation buildings are sometimes required to cater for asset replacements as it is not always possible to replace assets in-situ.

4.6.4.3 Asset acquisition

The replacement or major refurbishment of zone substation buildings will be triggered by the need to replace protection and control equipment, not by the age of the buildings alone. The following zone substations, subject to management approval of non-committed projects, will have new buildings:

- Rebuild of Zone Substation East Preston by 2022;
- New Zone Substation at Craigieburn in 2025 or later;
- Rebuild of Zone Substation Sunbury in 2018/19;
- New control room for BD, currently under construction as part of the relay replacement project; and
- New control room extension for CN is planned as part of the relay replacement project in 2022/23.

4.6.4.4 Asset Operation and Maintenance

The current asset maintenance program involves

- Monthly inspection conducted by operational employees;
- Annual Inspection conducted by engineering staff;
- reactive and corrective maintenance; and
- preventive maintenance

Inspection and general maintenance shall be provided on Zone Substations and the sites earmarked by JEN as “future Substation sites” that shall identify and rectify any defects, which relate to poor appearance, safety or environmental hazards.

A civil and structural engineering audit of Zone Substations shall be conducted on a 3-year cycle to monitor the integrity of all buildings and structures. Any deteriorated structures or buildings found shall be programmed for refurbishment or replacement.

Reactive and corrective maintenance is carried out when faults occur or after inspection has identified defects (or both), resulting in the repair of:

- Building/Enclosure roofs;
- Civil, masonry and brick work;
- Graffiti (removal/repainting);
- Plumbing systems;
- Safety issues (e.g. trip hazards);
- Security fences/signage;
- Vermin proofing; and
- Doors.

Cleaning of zone substation buildings shall be performed at regular intervals. The scope shall include grass-mowing, removal of unwanted vegetation, cleaning, sweeping and vacuuming of indoor substations.

Drainage systems and fall arrests on buildings shall be inspected and maintained annually. Inspection of the fall arrest systems shall be undertaken to ensure they are compliant with the relevant standards. Any repairs necessary to fences and gates would be identified and reported to Jemena contract officers, who would negotiate with the responsible site owner and inform the contractor of any works that he should undertake.

4.6.4.5 Asset Replacement/Disposal

The replacement or major refurbishment of zone substation buildings will most likely be triggered by the need to replace protection and control equipment, not by the age of the buildings alone. Whereas security fences with be replaced when the condition of posts and/or panels are beyond economical repair.

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

Table 4-59 lists the forecast CAPEX replacement volumes for Buildings and Grounds of Zone substations from 2019 to 2030, based on these drivers

Table 4-59: Forecast Replacement Volumes - Zone Substations Buildings and Grounds

Replacement Volumes – Grounds/Domestic Management of Zone Substations	Unit	Year											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Install triple interceptors for oil containment - Zone substations	ea	1											
New control building - CN	ea				1								
ZSS property minor CAPEX works	ea	1	1	1	1	1	1	1	1	1	1	1	1
No.1 transformer enclosure roof replacement - FW	ea		1										
No.1 transformer enclosure roof replacement - HB	ea		1										
Fences -FE			1										
Fences BY				1									

An internal business process (ELE PR 002 Portfolio Prioritisation Methodology) is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how Jemena prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work.

Table 4-60 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure.

Table 4-60: Specific Drivers - Zone substation Buildings and Grounds

Driver	Risk/Opportunity Description	Consequence
Asset Integrity, Safety, Health and Environment	Flashover due to vermin/flora/fauna Impeded substation access	Risk to employee safety and asset integrity
Asset Integrity, Safety, Health and Environment	Mal-operation of plant due to leaking roof	Risk to employee safety and asset integrity

The volumes of work required and associated capital and operational expenditure ensure that the consequences identified in the table above are addressed to maintain network performance and risk. It is recommended that these are prudent and efficient, and will ensure that the long term interests of customers are maintained.

Many of the older buildings contain asbestos or are asbestos clad and these need to be managed and disposed in accordance with EPA guidelines.

4.6.5 FUTURE IMPROVEMENTS

A security review of all JEN Zone Substations was conducted in 2017 and a Zone Substation Security Strategy was prepared shortly thereafter. Specific recommendations have been made to improve security and reduce risks. These are:

a) Access Control

Install a standardised electronic access control system on all external gates and internal doors on all Zone Substations. Access should only be granted to those sites and assets which personnel are required to work on and not common across the network unless required. The system should be managed via the existing Jemena security access card processes and procedures. I.e. Access applications to be made via the intranet and approved by relevant personnel.

b) Site Lighting

Install motion-sensor, timed or remotely activated floodlights to cover the entrance area and main external areas of all sites.

c) Security Monitoring

Install CCTV systems with on-board analytics capability and a real-time feed between all Jemena Zone Substations and a nominated control room (outsourced or in-house). Additionally, consider implementing response plans involving either a contract security provider or local police to attend if intrusion into a Jemena site is detected.

Trial installation of the security improvements are to be actioned in the near future at targeted zone substations. Zone substation AW storage area and zone substation COO have recently been equipped with monitored security cameras.

4.6.6 INFORMATION

Jemena's AMS provides a hierarchical approach to understanding the information requirement to achieve Jemena's business objectives at the Asset Class. In summary, the combination of Jemena's Business Plan, the individual Asset Business Strategy (ABS) and Asset Class Strategy (ACS) all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives Table 4-61. Table 4-62 identifies the current and future information requirements to support the Sub Asset Class critical decisions and their value to the Asset Class. Table 4-63 provides the information initiatives required to provide the future information requirements identified in Building and Grounds Business Objectives and Information Requirements Table 4-62. Included within this table is the risk to the Sub Asset Class from not completing the initiative.

All of the information required by the building and ground Sub Asset Class is available within Jemena's current business systems.

Table 4-61: Building and Grounds Business Objectives and Information Requirements

Business Objective	Jemena Information Sources	Externally Sourced Data
Maintain Safety, Security, and structural integrity of Buildings and Grounds	SAP DrawBridge Condition/maintenance reports Daily situation reports	VESI primary plant committee. Alerts – from DB's and Government Organisations and manufacturers. Manufacturing manuals. AS/IEC standards.

Table 4-62: Building and Grounds Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Building and Grounds - Asset Creation	Specifications requirements are located in the primary plant design manual Zone Substation Primary Design Standard New asset project progress reporting. Completion recorded in SAP Asset register in SAP		High: Regulated to maintain supply reliability, safety and quality of supply. Also a Competitive price structure and compliance to performance specifications requirements
Maintain functionality of Buildings and Grounds via Inspections, and audits	Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name • Address SAP Maintenance reports Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts SMI's – (Standard maintenance instruction) located on Jemena's Intranet.	Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	**Current Information Usage**	**Future Information Requirement**	**Value to Asset Class (High, Medium, Low with justification)**
	SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP		
Maintain functionality of Buildings and Grounds via Preventive Maintenance	Preventive maintenance tasks, schedules, progress and measurements as applicable in SAP. Scheduled task description, timing and completion recorded in SAP; Policies & Forms. SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP OPEX & CAPEX cost reporting recorded in SAP	Results are recorded in SAP and PM order scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. Hard copies of manufacturers manuals (where available) stored in Collins Street Melbourne compactus. All documents to be scanned and stored in Drawbridge. Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	High: Regulated to maintain supply reliability, safety and quality of supply
Respond to Buildings and Grounds defects including security breaches. Perform corrective maintenance.	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name • Address SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports and maintenance reports DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts Asset failure details and investigation reports. Stored in ECMS	Access all information via electronic tablet in the field. All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	OPEX & CAPEX cost reporting recorded in SAP		
Asset Class Strategy Review	Condition data Fault/failure data Maintenance & replacement costs AMS		Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-63: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	To improve analysis and decision making. Asset data available from business systems saving on site trips.	Poor efficiency in accessing asset data	Asset Data as per SAP requirements.

4.7 ZONE SUBSTATION EARTHING SYSTEMS

4.7.1 INTRODUCTION

The Earthing Systems Asset Sub-Class Strategy applies to earthing systems installed in Zone Substations.

The Earthing Systems Asset Class Strategy provides an asset overview, while identifying the most appropriate strategies and plans for managing assets over their lifecycles.

The Asset Class Strategy is based on key information about each asset including risk, performance, capital expenditure and operational expenditure. Based on this information, the Asset Class Strategy provides details about the Jemena Electricity Network's (**JEN**) earthing systems asset class strategies for the next five years, and comprises five key areas:

- **Asset class profile** includes information about the type, specifications, life expectancy and age profile of earthing systems in service across the JEN.
- **Asset strategy** outlines earthing systems asset management practices. This includes key earthing systems strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and programs of work. See Section 4.7.4 Life Cycle Management.
- **Asset risk** includes information about asset risk, including causes and consequences. See Section 4.7.2 Risk.
- **Asset performance** provides information about performance objectives, drivers, and service levels, and the technical and commercial risks associated with earthing system management. See Section 4.7.3 Performance.
- **Asset expenditure** assessment provides information about the expenditure decision-making processes (and how expenditure options are analysed) as well as forecast operating and capital requirements. See Section 5 Consolidated Plan.

The Asset Class Strategy for Earthing Systems is intended to ensure the ongoing performance of the Jemena Electricity Network (**JEN**) and to mitigate 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.

In the past, distribution substations were installed with separate HV and LV earthing systems. Common industry practice today is to combine the HV earth system with the LV Multiple Earthed Neutral (**MEN**) system, to form a Common Multiple Earthed Neutral (**CMEN**) system. JEN's practice is now to take this one step further and to combine the zone substation earth grids to the CMEN system.

The principle of establishing a CMEN system is to reduce the hazard presented by conductive HV structures by extending the HV earthing system beyond the locally earthed HV structure (eg. distribution substation, cable head, switch, concrete pole) and utilising the low voltage MEN network to contribute to a lower impedance path to earth. This is implemented in conjunction with the deployment of a Neutral Earth Resistor (**NER**) at zone substations to reduce the magnitude of earth fault currents so that the safety criteria for CMEN systems can be met. Thus the CMEN system is a very efficient way of utilising the extensive LV MEN network to ensure compliance with step and touch voltages arising from HV to ground faults.

This excludes 66kV earthing systems, which are not covered by CMEN schemes.

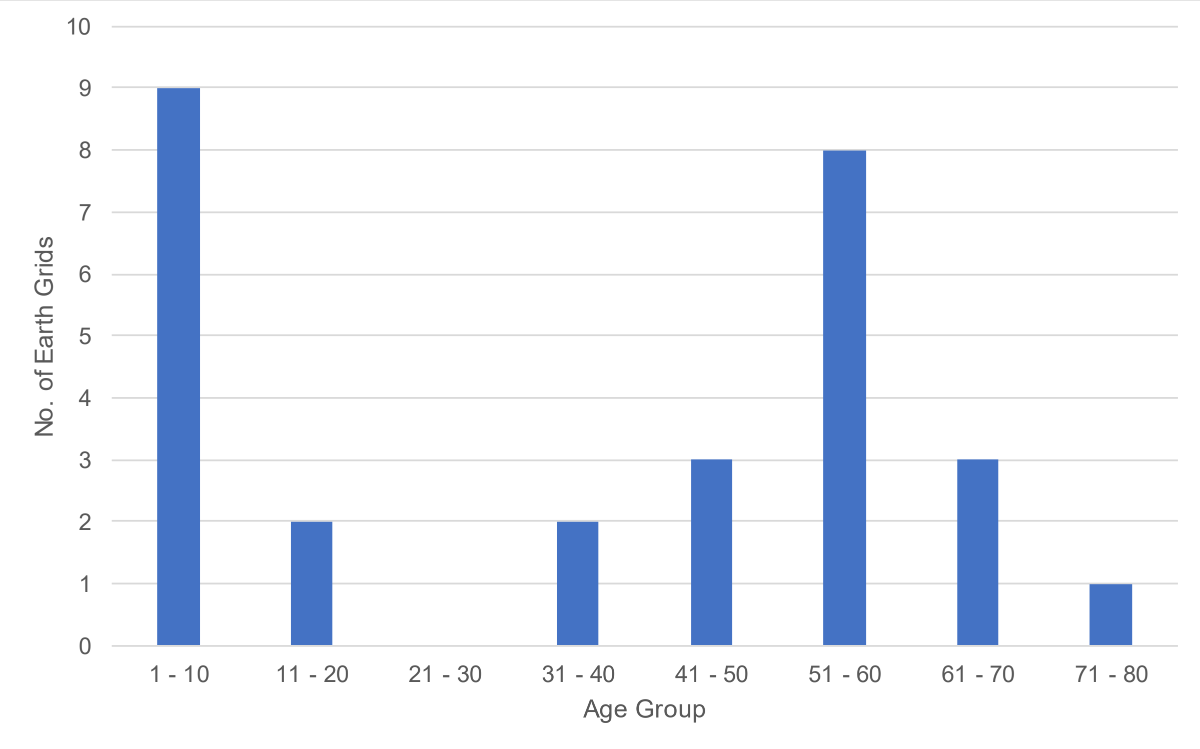
4.7.1.1 *Asset Specification*

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, aluminium, and stainless steel.

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.

Figure 4–28 shows the current zone substation earth grid age profile.

Figure 4–28: Zone Substations Earth Grids Age Profile



The age of zone substation earth grids is roughly equivalent to the age of zone substation buildings as the earth grid and building is established at the same time.

4.7.2 RISK

This chapter includes information about earthing system risk profiles involving the way that asset class criticality is established, the risks posed by earthing 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 earthing systems.

This information specifically involves:

- Asset class criticality score (sub asset class level) for ranking of critical assets;
- Failure modes and effects (RCM) for establishing maintenance programs;
- Current risks;
- Existing controls;
- Asset Spares;

- Contingency; and
- Future risks (involving other potential risk issues currently being managed).

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.

Although it rarely occurs, there is the potential for an earth voltage rise to cause injury or death to staff, contractors or members of the public. This could occur if the safety performance of the earthing system fails to meet standards and is non-compliant.

Non-compliance with the Electricity Safety (Management) Regulations 2009 will lead to general regulatory queries from the technical regulator, Energy Safe Victoria.

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 JCAR[10].

Emerging risks include:

- Ageing installations with likely deterioration of earth grids; and
- Changes to network fault levels requiring enhanced earth grids.

4.7.2.1 Criticality

Asset criticality is a measure of the risk of specified undesired events faced when utilising equipment. Asset criticality assessment was conducted at the sub asset class level by following the Asset Criticality Assessment Procedure (JEM AM PR 0016). Results of this assessment are presented in Appendix J. The asset criticality score was then utilised to rank critical assets which have the potential to significantly impact on the achievement of Jemena'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 systems has an asset criticality score of AC4 (High) due to the health and safety consequences associated with failures.

Classification: High Criticality

Inability to detect earth faults preventing the operation of HV protection systems.

There is health and safety risk to staff and the general public caused by step and touch potentials.

4.7.2.2 Spares

It was determined that earthing conductors and connection materials are available from stock, including CMEN and ZCMEN labels, are constructed of commercially available hardware and equipment; therefore any required material can be purchased from suppliers. Spares requirements for

[10] For more information on JCARs please click here.

critical assets using the Critical Spares Assessment Procedure (JEM AM PR 0015) is not relevant in this case.

Earthing conductors and connection materials are available from stock, including CMEN and ZCMEN labels. Earthing system components are stocked in the stores and replenished as required

4.7.2.3 Failure Modes

Likely failure modes for substation earthing systems include:

- Corrosion of buried earth grid conductors – can result in high resistance or open circuit;
- Physical damage to or missing structure to earth grid connections;
- High resistivity soil – can result in high resistance between soil and buried conductors; and
- High resistance joints between earth grid conductors and between grid and connections to above ground structures

4.7.2.4 Existing Controls

Existing controls are essentially those detailed in the recommended condition monitoring and maintenance tasks documented in section 4.7.4.2, together with initiation of augmentation projects for assets determined to not comply with EPR limits determined by testing.

Contingency plans essentially are immediate response by field crews to assess the extent of damage and repair ability of the assets. Once determined, repairs can be actioned utilising materials in stock.

4.7.3 PERFORMANCE FACTORS

The primary objective of employing earthing systems is to maintain effective earthing systems associated with zone substations to ensure safety to personnel and public.

SAP records of substation earthing system defects and repairs are available and there is no significant increase in defects and repairs over previous years.

4.7.3.1 Requirements

There is a regulatory requirement to verify the earthing system for zone substations at least once every 10 years. In the event that the earthing system at a particular location does not meet the minimum requirements, the existing earthing system is assessed, possibly redesigned, and augmented as necessary to reduce the impedance to acceptable levels.

In 2013, there has been a major change in the earthing system methodology for zone substations. Zone substation earthing system design has previously been based on the legacy design standards established by the SECV where, there is a separation and isolation of the zone substation earth grid from the external distribution network earthing system and from any conducting structure or mediums that would facilitate the transfer of any hazardous potential rise that occurs on the zone substation earth grid to surrounding infrastructure. A program has been initiated such that the zone substation feeder exit cables are bonded to the CMEN system, effectively extending the zone substation earth grids to the CMEN area. This methodology is detailed in ST-PPDS-2013-087 JEN Strategic Planning Paper – Earthing Systems. The point of connection between the ZSS earth grid and the distribution network CMEN is labelled ZCMEN.

Earth grids and earth connections installed in zone substations are expected to have the same life as the substation, that is in excess of 50 years.

4.7.3.2 Assessment

A number of factors are assessed to determine if earthing systems have a high reliability that they will continue to perform reliably its required function. Aspects such as age, condition, utilisation, effectiveness of risk controls and analysis of actual performance are examined. The following reports provide data for these areas.

SAP records of zone substation earth systems defect and repairs. When we issue an order to undertake defect/repair work, then this will be recorded in SAP PM order. The SAP notification (if raised) will record the cause code.

Common issues found during earth grid testing include inadvertent bonding of the zone substation earth grid to the CMEN system, corroded earth grid connections, connections that have not been welded, step and touch issues in and around the zone substation including at neighbouring properties. A project to bond the zone substation earth grids to the CMEN system was initiated in 2015. Majority of Jemena's electricity zone subs have been successfully bonded to the CMEN and this has resulted in a very low earthing system impedance at the zone substation. This makes the substations very safe and results in cost savings of thousands of dollars to carry out remediation work.

A review of the adequacy of zone substation earthing with respect to AS2067 is being undertaken. Findings will be addressed according to the risk profile.

At EPN, the CMEN links to the zone substation earth grid had to be disconnected as there weren't enough feeders coming out of EPN. In 2021/22 when EP gets decommissioned, there will be more feeders commissioned at EPN. The zone substation to CMEN bonds will be re-established then to ensure we get a minimum of 4 feeders connected.

The utilisation of earthing systems is considered to be high as they are continuously in service.

Controls employed (inspection, condition monitoring & maintenance) and condition based replacements completed are identified below. These have been employed to manage the identified risks.

By comparing identified risks and measuring past incidents, an assessment of the effectiveness of the existing controls can be seen in the following table*:*

Table 4-64: Controls effectiveness

Risk Category	Cause/incident	Controls	Incidents in past 5 years
Health, Safety & environment	Earthing systems failure – people safety and or environment impact	Asset Management strategy applied. Earth grid tested and mitigation work implemented. Except for EP Replacement projects completed	Nil
Regulatory & Compliance	Failures results in non-compliance notice/ penalties	Asset Management strategy applied. Replacement projects completed	Nil
Financial	Rectification of failures results in significant unplanned cost	Asset Management strategy applied. Replacement projects completed	Nil
Operational	Failures result in loss of supply to customers	Asset Management strategy applied. Replacement projects completed	Nil

4.7.4 LIFE CYCLE MANAGEMENT

This chapter includes information about earthing system asset management practices, including key earthing strategies and plans that support the corporate business plan, strategies and objectives, and inform expenditure plans and work programs.

Specific aspects of the asset strategy involve information about:

- Asset lifecycle management options;
- Asset creation (including asset acquisition and asset spares);
- Asset maintenance (involving inspection, reactive and corrective maintenance, preventive maintenance, and condition-based monitoring);
- Asset disposal; and
- Future improvements

4.7.4.1 Lifecycle management options

The options available for asset lifecycle management reflect a trade-off between capital and operating expenditure

The lifecycle management options for earthing systems are:

- Condition Based Replacement or Refurbishment;
- Proactive Replacement Programs based on age; and
- Run to Failure

Condition based replacement or refurbishment is the preferred lifecycle management option.

Replacement or augmentation of earthing system equipment is typically required when periodic inspection and testing or notification of an incident, reveals degradation of that system. Degradation can take the form of conductor and connector corrosion, mechanical fatigue, vandalism or inadvertent damage due to excavation.

Earthing system augmentation is undertaken when step touch and transfer potentials are identified as exceeding the maximum safe limits.

There is no proactive replacement of earthing systems, as condition based monitoring in the form of inspection and testing are relatively inexpensive and focuses on issues identified. Moreover, periodic inspection of earthing systems is a regulatory requirement.

Periodic inspection and testing of earthing systems is a JEN internal technical standard and the run-to-failure management option cannot be applied as this would not comply with the Electrical Safety (Management) Regulations 2009.

4.7.4.2 Regulations and Standards

The Electricity Safety (Management) Regulations 2009 prescribes that JEN will comply with its internal technical standards. JEN internal standards reflect the Electricity Safety (Network Assets) Regulations 1999 to which the JEN assets have been designed, constructed and maintained. 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 requirement for inspection and testing of earthing systems in zone substations and non CMEN areas within 10 years. ESV has reviewed and approved JEN’s ESMS.

4.7.4.3 Creation

Earthing systems are initially installed as part of new installations of zone substation assets.

These earthing systems may be expanded if condition based monitoring dictates or if augmentation projects occur at a substation.

4.7.4.4 Asset Operation and Maintenance

This section provides information about the current asset maintenance program.

The current asset maintenance program involves:

- Condition based monitoring in the form of inspection and testing; and
- Reactive and corrective maintenance

At 10-year intervals the following shall be undertaken to ensure earth grids continue to comply with safety criteria:

- Sample inspections of underground conductors & conductor joints shall be conducted to check for any corrosion or damage. As part of this check, a “transfer hazard check” shall be conducted to ensure no new underground pipelines, metallic communications cables, and unauthorised connections have been made to the perimeter fence.
- A grid continuity test shall be conducted. This test can use portable instruments and measure between a main earth grid reference connection and each structure earthing point. This is particularly important for high energy dissipation points such as surge arrester, portable earth, and earthing switch earth connection points.
- An annual inspection shall be undertaken of all above ground structure earth to earth grid connections for all HV and LV equipment. are still required even with the new strategy of bonding the zone substation earth grid to the CMEN network

The following inspection requirements are to be adhered to for Earthing Systems:

- Check that earthing and bonding connections to equipment such as transformers, switchgear, cable sheaths, support framework, cubicles etc. are intact;
- Inspect flexible bonding braids for fracture or corrosion during maintenance and switching operation;
- Inspect main earth conductor above ground for signs of damage;
- Inspection of the ZMEN connection as part of the pole and line inspection program;
- Check 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; and
- Verify all neutral earth connections are intact.

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).

4.7.4.5 Asset Augmentation and Replacement

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

Table 4-65 lists the forecast CAPEX augmentation volumes for earthing systems from 2019 to 2030.

Table 4-65: Replacement Volumes - Earthing Systems

Augmentation Volumes – Earthing Systems	Unit	Year											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Upgrade zone substation earth grids	ea			1		1		1		1		1	

A capital project prioritisation process is used to rank projects that are proposed for inclusion in the annual capital works program. This process forms part of a quantified framework of applying specific risk management techniques and methodology to the development of the wider program of capital works and the principles of this approach articulate how JEN prioritises and optimises its investments.

More broadly, JEN looks at the specific asset class drivers for the particular capital/operational programs, including identifying the consequences of not completing proposed volumes of work

Table 4-66 provides an overview of the asset class specific drivers of the proposed replacement volumes and expenditure

Table 4-66: Specific Drivers- Zone Substation Earthing Systems

Driver	Risk/Opportunity Description	Consequence
Environment, Safety and Health	Earth potential rise	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.

The volumes of work required and associated capital and operational expenditure ensure that the consequences identified in the table above are addressed to maintain network performance and risk. It is recommended that these are prudent and efficient, and will ensure that the long term interests of customers are maintained.

4.7.4.6 Disposal

Earthing systems are typically not removed from service, however should disposal be required; it is scraped according to the scrap material policy. Refer to JEM PO 1066 – Scrap Materials Policy for details.

4.7.4.7 Future Improvements

Future improvement to the management of earthing systems will be to complete the CMEN distribution network earthing system program and the implementation of the Ground Fault Neutralizer system of resonant earthing at all high exposure bushfire zone substations on JEN over the next 5 years.

Plus decommissioning of EP which does not have an NER for the 6.6kV distribution voltage.

4.7.5 INFORMATION

Jemena's AMS provides a hierarchical approach to understanding the information requirement to achieve Jemena's business objectives at the Asset Class. In summary, the combination of Jemena's Business Plan, the individual Asset Business Strategy (ABS) and Asset Class Strategy (ACS) all provide the context for and determine the information required to deliver an Asset Class's business.

The high-level information requirements to achieve the ACS's business objectives and inform its critical decisions were identified at a facilitated workshop during the ACS definition process.

From these business objectives, it is possible to identify at a high-level the business information systems' content required to support these objectives (Table 4-67). Table 4-68 identifies the current and future information requirements to support the Sub Asset Class critical decisions and their value to the Asset Class. Table 4-69 provides the information initiatives required to provide the future information requirements identified in Table 4-68. Included within this table is the risk to the Sub Asset Class from not completing the initiative.

All of the information required by the transformer Sub Asset Class is available within Jemena's current business systems.

Table 4-67: Earthing System Business Objectives and Information Requirements

Business Objective	Jemena Information Sources	Externally Sourced Data
Maintain Safety, availability and reliability of Earthing Systems	SAP DrawBridge Condition/maintenance reports Daily situation reports	VESI primary plant committee. Alerts – from DB's and Government Organisations and manufacturers. Manufacturing manuals. AS/IEC standards.

Table 4-68: Earthing System Critical Decisions Business Information Requirements

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
Earthing System - Asset Creation	Zone Substation Primary Design Standard New asset project progress reporting. Completion recorded in SAP Asset register in SAP		High: Regulated to maintain supply reliability, safety and quality of supply.
Maintain functionality of Earthing Systems via Inspections, and audits	Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name • Address SAP Maintenance reports Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports	Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	DrawBridge – Single line diagrams, plant data, design drawings/layouts SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP		
Maintain functionality of Earthing Systems via Regulatory Testing requirement (10 yearly interval)	Regulatory testing tasks, schedules and progress in SAP Scheduled task description, timing and completion recorded in SAP; Policies & Forms. SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP OPEX & CAPEX cost reporting recorded in SAP Test reports Fault current level calculation outputs. Published annual Distribution Planning Report available on Jemena website.	Results are recorded in SAP scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. All documents to be scanned and stored in Drawbridge. Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	High: Regulated to maintain supply reliability, safety and quality of supply
Respond to Earthing System defects / faults to restore equipment operationally. Perform corrective maintenance.	Alerted via JEN Control Room or situation report. Asset register SAP, with details of each asset and significant components; • Equipment description • Construction year • Location: Zone substation name • Address SAP notifications and work orders activities performed and components replaced. Details of work completed recorded in SAP Performance history: • Daily situation reports • Investigation reports (ECMS) • Plant defect reports and maintenance reports DrawBridge – Single line diagrams, plant data, OEM manuals, design drawings/layouts	Results are recorded in SAP scanned and stored on the shared network folder. All maintenance reports to be attached to the relevant SAP equipment. All documents to be scanned and stored in Drawbridge. Access all information via electronic tablet in the field. All data to be collected and stored within SAP to enable effective root cause analysis in a timely manner.	High: Regulated to maintain supply reliability, safety and quality of supply

Critical Business Decision	Current Information Usage	Future Information Requirement	Value to Asset Class (High, Medium, Low with justification)
	Asset failure details and investigation reports. Stored in ECMS OPEX & CAPEX cost reporting recorded in SAP		
Asset Class Strategy Review	Condition data Fault/failure data Maintenance & replacement costs AMS		Medium: Allows strategy to be fine-tuned when changes to performance and/or costs or environment alter

Table 4-69: Information Initiatives to Support Business Information Requirements

Information Initiative	Use Case Description	Asset Class Risk in not Completing	Data Quality Requirement
Migrate Condition & Performance reports/data into SAP Access all information via electronic tablet in the field. Update asset data in SAP for missing data.	To improve analysis and decision making. Asset data available from business systems saving on site trips.	Poor efficiency in accessing asset data	Asset Data as per RCM and SAP requirements.

5 CONSOLIDATED PLAN

This chapter provides information about;

- capital requirements;
- operational requirements, and;
- expenditure assessment and recommendation.

Implementation of this Asset Class Strategy is achieved by the following, organisation, resources and activities;

- Jemena's SAP system provides:
  - An register of assets;
  - Facilitate scheduling of both Operational and Capital works;
  - Record of cost of works against assets;
  - Enable reporting of work progress and costs;
  - Recording defects and scheduling repairs plus recording of condition monitoring results;
- Services & Projects provide:
  - A field work force and organisation to perform hands on work and manage and report on these activities as defined by Asset Management, and documented in the Asset Investment Plan (AIP) and Capital and Operational Work Plan (COWP).
- All projects and programs of work are controlled utilising a standardised Project Management Methodology (PMM). Procedures are detailed in the Project Management Procedure JEM PMM PR 2500.

5.1 CAPITAL FORECAST

Forecast CAPEX Expenditure ($'000)

Project Name	Service Code	CY20	CY21	CY22	CY23	CY24	CY25
10yr Testing of ZSS Earth Grids	RSA	–	62,459	62,023	62,741	63,624	63,886
Audit Test Equipment - binoculars, corona etc.	RSA	–	10,000	–	20,000	–	–
Condition Monitoring Software -	RSA	–	–	–	200,059	–	–
Miscellaneous Primary Plant (reactive work)	RSA	–	499,672	-	501,926	-	511,090
No.1 Transformer enclosure roof replacement - HB	RSA	–	128,122	–	–	–	–
No.3 Transformer Enclosure Roof Replacement - FW	RSA	143,618	–	–	–	–	–
Replace 22kV Switchgear - CN	RSA	–	–	623,758	5,308,977	–	–
Replace 22kV Switchgear - CS	RSA	–	–	–	–	2,260,939	5,149,866
Replace 66kV Brown Insulators	RSA	–	187,377	–	188,222	–	191,659
Replace 66kV CB's (1) - FE	RSA	342,739	–	–	–	–	–
Replace 66kV CB's (1) - HB	RSA	255,763	–	–	–	–	–
Replace Cap Bank CB's - FE & FW	RSA	–	849,079	–	–	–	–
Replace Capacitor cans	RSA	–	11,832	11,749	11,885	12,137	12,187

Project Name	Service Code	CY20	CY21	CY22	CY23	CY24	CY25
Replace CN 66kV 1-2 Bus-Tie CB	RSA	–	–	182,597	185,136	–	–
Replace Ducon Capacitor Bank	RSA	–	–	–	950,814	–	–
Replace ES Transformers	RSA	344,276	–	–			
Replace FE Fence	RSA	246,436	–	–	–	–	–
Replace FE Switchgear	RSA	3,324,477	1,104,298	–	–	–	–
Replace FF Transformers	RSA	–	–	–	–	–	–
Replace FW 66kV CBs	RSA	321,984	189,171	–	–	–	–
Replace FW Switchgear	RSA	2,401,670	4,798,261	590,405	–	–	–
Replace HB Transformers	RSA	3,475,080	4,325,489	1,207,680	–	–	–
Replace transformer bushings	RSA	–	35,495	35,248	35,656	36,412	36,562
Replace ZSS Fences	RSA	–	118,318	–	118,852	–	121,872
Subtransmission Installation Replacement	RSA	58,000	111,400	110,117	118,304	124,805	129,953
Transformer Oil Regeneration	RSA	–	–	186,070	–	–	191,659
Upgrade zone substation earth grids	RSA	–	218,808	-	219,795	–	223,808
ZSS Property Minor CAPEX Works	RSA	130,586	116,496	115,683	117,021	118,669	119,158
ZSS Spare Equipment	RSA	–	–	248,094	–	254,497	–

Project Name	Service Code	CY20	CY21	CY22	CY23	CY24	CY25
Install triple interceptors for Oil Containment - BY	RSA					379,070	
Control Building - CN	RSA			574,449	582,437		
Control Room Roof Replacement	RSA			134,434	135,988		
NH window replacement	RSA		185,759				
AW and BD 22kV pin and cap insulator replacement	RSA		321,470	330,085			
Replace BD Transformer	RSA		2,958,813	1,180,809			
ZSS Security Cameras & Lights	RSA		118,318	117,493	118,852	121,372	121,872
Replace 22kV Switchgear - BLTS	RSA					820,112	
Circuit Breaker Wear Monitoring Equipment	RSA						638,863
Total	RSA	11,044,629	16,350,637	5,710,694	8,876,665	4,191,637	7,512,435

5.2 OPERATING AND MAINTENANCE FORECAST

Forecast OPEX Expenditure ($ '000)

SAP Code	Description	2020	2021	2022	2023	2024	2025
MPA	Zone Substation Property Maintenance	$167	$171	$175	$180	$184	$189
MPB	Zone Substation Property Maintenance Defects	$86	$88	$90	$93	$95	$97
MZA	Zone Substation Equipment Maintenance - Primary	$983	$1,008	$1,033	$1,059	$1,085	$1,112
MZC	Zone Substation Defect Maintenance - Primary	$314	$322	$330	$338	$347	$355
MZI	Zone Substation Inspection and Audits	$145	$149	$152	$156	$160	$164
FZA	Zone Substation Primary Faults	$24	$25	$25	$26	$26	$27
	Total	$1,719	$1,763	$1,805	$1,852	$1,897	$1,944

6 GLOSSARY

6.1 ZONE SUBSTATION ABBREVIATIONS

Substation	Suburb
AW	Airport West
BD	Coolaroo
BMS	Broadmeadows
BY	Maidstone
CN	Coburg Nth
COO	Coolaroo
CS	Coburg Nth
EP	Preston
EPN	Preston
ES	Essendon
FE	Yarraville
FF	Fairfield
FT	Flemington
FW	Yarraville
HB	Heidelberg
MAT	Melbourne Airport
NEI	Heidelberg West
NH	Macleod
NS	Essendon
NT	Newport
PTN	Preston
PV	Pascoe Vale
SBY	Sunbury
SHM	Sydenham
SSS	Somerton
ST	Somerton
TH	Tottenham
TMA	Tullamarine
VCO	Coolaroo
YVE	Yarraville

6.2 ACRONYMS

ABS	Asset Business Strategy
AC	Alternating Current
ACR	Automatic Circuit Recloser
ACS	Asset Class Strategy
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMS	Asset Management System
BAU	Business As Usual
BI	Business Intelligence
CATS	Customer Administration Transfer System
CBRM	Condition Based Risk Management
COWP	Capital Operating Works Program
CPU	Central Processing Unit
CT	Current Transformer
DAPR	Distribution Annual Planning Report
DC	Direct Current
DNSP	Distribution Network Service Provider
EDPR	Electricity Distribution Price Review
ENA	Energy Networks Association
EOL	End of Life
EPA	Environment Protection Authority
ERP	Enterprise Resource Planning
ESCV	Emergency Services Commission of Victoria
ESMS	Energy Safe Management Scheme
ESV	Energy Safe Victoria
EUSE	Expected Unserved Energy
GPS	Global Positioning System
HSE	Health, Safety and Environment
HV	High Voltage
I/O	Input/Output
IED	Intelligent Electronic Device (typically a digital protection relay)
JCAR	Jemena Compliance & Risk System
JEN	Jemena Electricity Networks (Vic) Ltd
JSAP	Jemena SAP
KPI	Key Performance Indicator
kV	kiloVolt
KVAR	Kilo-Amps-Volts-Reactive
KW	Kilowatt
LCD	Liquid Crystal Display
LV	Low Voltage
MAMS	Metering Asset Management Strategy
MDM	Meter Data Management
MIB	Management Information Base
MTBF	Mean Time Between Failure
MW	Megwatt
NER	National Electricity Regulator
NIC	Network Interface Card
NMS	Network Management Systems

PQCA	Power Quality Compliance Audit
PQM	Power Quality Meter
PSCN	Power Supply Control Network
RAM	Random Access Memory
RIN	Regulatory Information Notice
ROM	Read Only Memory
RTS	Real Time System
RTU	Remote Terminal Unit
SAP	Proprietary name for ERP software
SCADA	Supervisory Control and Data Acquisition
SMR	Switch Mode Rectifier
VEDC	Victorian Electricity Distribution Code
VESC	Victorian Electricity System Code
VT	Voltage Transformer
ZSS	Zone Substation

6.3 TERMS AND DEFINITIONS

capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
operating expenditure (OPEX)	Expenditure (ongoing) for running a product, business, or system.
Asset	Refers to the collection of tangible and non-tangible assets required to provide a product or service to its customers. Jemena consists of the following Assets: Jemena Electricity Network (JEN), Jemena Gas Network (JGN), Queensland Gas Pipeline (QGP), Eastern Gas Pipeline (EGP), Northern Gas Pipeline (NGP), Colongra Gas Pipeline (CGP), evoEnergy (EVO).
Asset Class	A separation of the Assets into smaller manageable components that enable decision-making relating to implementing broader strategies in a meaningful way. Example is Primary Plant.
Asset Management Plan (AMP)	The Asset Management Plan provides the optimised plan to manage the assets, understanding the existing and future customer requirements and operating environments, balancing the competing requirements of financial constraints, commercial & business objectives, regulatory requirements, and asset condition (including risk/opportunities). It informs the 7 year operational and capital expenditure and the two-year plan of work.
Asset Management Policy	A short statement that sets out the principles by which Jemena intends to apply asset management to achieve its objectives.
Sub-asset Class	A separation of an asset class into smaller manageable components that enable decision-making relating to implementing broader strategies in a meaningful way. An example is Circuit Breaker.
Sub-asset Class Element	A further separation of an sub asset class into smaller manageable components that enable decision-making relating to implementing broader strategies in a meaningful way. An example is a Boric Acid Fuse.

7 APPENDICES

7.1 APPENDIX A – PREVENTIVE MAINTENANCE CLASS FOR TRANSFORMERS

There are five classes of preventive maintenance.

Class 1

This class requires the overhaul of the OLTC mechanism based on the number of operations or time since the previous overhaul (every two to six years, depending on type). In areas where transformers are subjected to high humidity and heavy pollution, the overhaul period may be reassessed.

Overhaul includes greasing and lubrication, cleaning and checking of mechanical and electrical switches, checking the integrity of weatherproof seals, and a functional test of mechanical drives.

Class 2

This class requires a combined mechanism and diverter switch overhaul every six years or sooner if required by operating duty. If the history of the tap-changer indicates more regular inspection is required, the period of overhaul can be varied.

Overhaul requires checking diverter contact wear, connection tightness, inspection for sign of insulation failure, oil filtering, and a functional test of tap-changer drives.

Class 3

This class requires overhaul of the OLTC tap-selector. In a combined diverter/selector switch, the overhaul is carried out at the same time as the Class 2 maintenance. If the tap-selector is located in a separate compartment to the diverter switch and is therefore free of contamination by arcing residues in oil, then the condition of the selector switch is monitored annually via a dissolved gas analysis (DGA).

Class 4

This class includes a combination of Class 2 maintenance and an overhaul of the transformer’s exterior (with a minimum to maximum maintenance interval of 4 to 6 years, respectively).

Overhaul work includes: main tank and radiator oil leak repairs via either tightening bolts or replacing gaskets; bushings, surge arresters, and neutral isolator cleaning; instrument and forced cooling checks; painting; and surge arrester insulation resistance checks.

Class 5

This class requires a workshop transformer overhaul. A major repair/refurbishment task, this class is only conducted when an internal core or winding fault is detected, or when the unit is to be upgraded to supply a higher load.

Typical works may include rewinding, a complete transformer dry-out, overhaul of bushings and tap-changers, gasket replacement, oil leak repairs, and painting.

Major repairs

Refurbishment

Refurbishment of aged zone substation transformers is labour-intensive and involves de-tanking the transformer and installing new windings, which is generally not economically viable when compared to replacement.

This class types viability is questionable to cost and replacement should be considered as an alternative.

Major transformer repair normally occurs in a workshop and is generally only required if the:

- transformer has developed an internal core or winding fault, or
- major paper insulation system is seriously degraded by moisture, affecting the transformer's reliability and life expectancy.

A major repair may also be performed when a transformer is being upgraded to carry a higher load, which typically includes internal work and external work.

Internal work involves:

- removing the core and coil assembly from the tank and checking tapping leads and connections and their associated supports;
- checking internal insulation for damage and defects;
- checking winding blocks and coil clamping;
- flushing the core and coil assembly and cooling ducts with insulating oil; and
- checking the insulation of all accessible core bolts and between the core and the core frame.

External work involves:

- replacing the tank lid, bushings and valve gaskets;
- overhauling the radiators, valves, conservators, oil gauges, and tap-changer drives; and
- filtering and reconditioning the insulating oil.

7.2 APPENDIX B – CONDITION-BASED MONITORING

Condition-based monitoring

Component-specific condition-based monitoring involves the following transformer and zone substation components and equipment:

- oil sampling and testing;
- dissolved gas analysis;
- degree of polymerisation value;
- infra-red thermal imaging;
- high voltage bushing monitoring;
- tap-changers;
- winding temperature indicators;
- station service transformers; and
- neutral earthing resistors.

Oil sampling and testing

Annual oil tests conducted to provide information about a power transformer's condition include:

- dielectric strength;
- acidity;
- water content;
- interfacial tension; and
- oil particle counts.

Dissolved gas analysis

Transformer core and coils

Transformer oil dissolved gas analysis (DGA) is conducted at least once a year and is more widely used to diagnose incipient faults or defects before they develop into major problems. The technique can also be used after a fault has occurred to assist with the diagnosis of the failure cause.

A DGA test, which measures the internal health of the core and windings:

- determines the volume and ratio of gases such as hydrogen, methane, ethylene, ethane, acetylene and carbon oxide dissolved in the transformer oil; and
- indicates a developing internal transformer fault as well as providing more general information about transformer insulation system ageing (depending on the composition and the amount of gases collected).

Tap changers

Tap-changers can also be monitored via a DGA. To deal with high levels of gas developed during normal switching operations, a series of gas ratios and criteria to interpret the oil test results have been specifically developed for OLTCs.

In terms of maintenance and monitoring:

- With the move to new tap-changer designs that require minimal maintenance, the introduction of a non-intrusive and cost-effective condition-monitoring test is considered prudent; and
- Oil sampling for DGA analysis should occur annually (facilitated by units with gate valves).

Degree of polymerisation value

The principle measure of a transformer's life is the condition of its insulating paper. The insulating paper's degree of polymerisation (DP) value is an indicator of its condition, which can be obtained from paper samples. **Table 7-1** summarises the relationship between the DP value and the condition of the insulating paper.

Table 7-1: Relationship between DP Value and Transformer Paper Insulation Condition

DP Value	State of Insulating Paper
1,200	Fresh paper.
800 – 1,000	Dried-out paper in a new transformer.
700	Initial value for a new transformer in service.
200	End of reliable use as an insulating material in a transformer.

In terms of a transformer's DP assessment, a DP value:

- of 200 means the transformer is at end-of-life and requires replacement; and
- below 200 means a transformer is unreliable.

Transformer winding insulation failures have occurred at DP levels of 300, and the risk of failure depends on the probability of a fault occurring close to a zone substation.

For more information about how DP values are established, see Appendix C.

Infra-red thermal imaging

Infra-red thermal imaging of transformers is carried out as a part of the annual thermal inspection program to identify external problems associated with poor connections or auxiliary equipment operating at abnormally high temperatures.

High voltage bushing monitoring

Transformer bushing failures have been recognised as a common point of transformer failure creating a hazard to people in the surrounding area as well as damage to the transformer. As a result, a bushing condition monitoring program has been implemented to measure the dielectric dissipation factor (DDF) of 66 kV transformer bushings.

Undertaken on a five-year cycle, the DDF test indicates the condition of the bushing's insulation and can reduce the risk of explosive failure.

The results of this bushing condition monitoring program will directly feed into the bushing replacement program, and provision has been made in the capital expenditure program for the replacement of bushings with deteriorated insulation and excessive moisture content.

Legacy bushing types

The old State Electricity Commission of Victoria (SECV) standardised the 66 kV bushings for all power transformers manufactured before the 1980s. These bushings:

- are a synthetic resin bonded paper (SRBP) type used widely in many zone substation transformers; and
- were purchased on period contracts and supplied to transformer manufacturers to be fitted to the transformers during assembly.

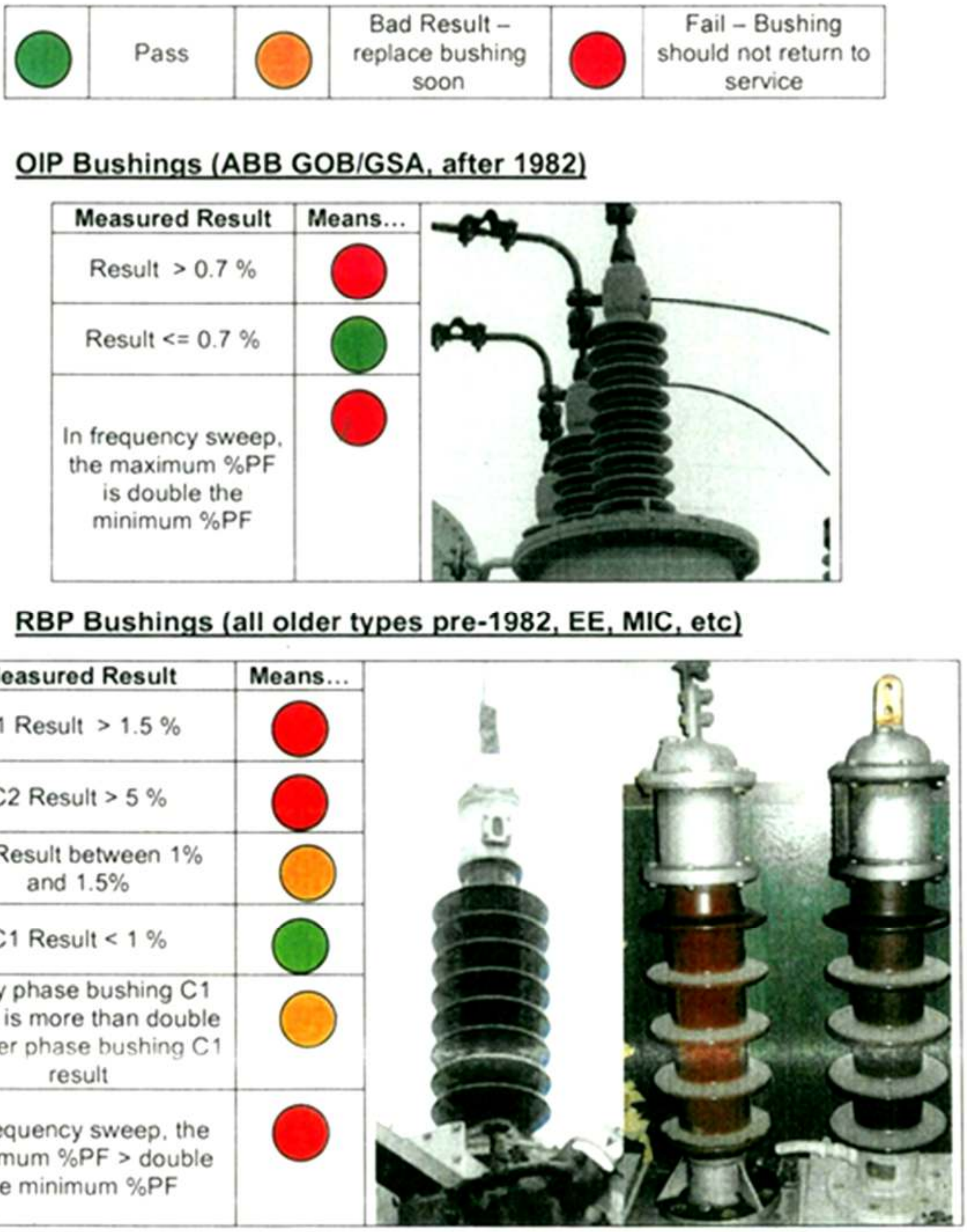
Moisture penetration and DDF testing

Moisture penetration can lead to electrical discharge and failure and often results in explosion. The probability of moisture ingress increases with age, making DDF measurements for moisture content important. The measurements are compared to the DLA Testing Tan Delta Result Card as per Figure 7–1.

Twenty-one bushing defects have been identified by the condition monitoring program. In one case the DDF testing has measured a leakage current above recommended values and consequently the bushing was replaced.

The failure mode of oil impregnated (OIP) bushings is significantly worse than the SRBP type. As a result, all future 66 kV bushing replacements will ideally be of a resin impregnated (RIP) silicon rubber housed type.

Figure 7–1: DLA Testing Tan Delta Result Card



Tap-changers

The number of tap-changer operations and their associated operating mechanisms varies on a daily basis, and their condition must be monitored and regular maintenance performed to ensure reliable operation.

Issues that can arise involve the following:

- High contact resistance inside tap-changers can result in overheating, resulting in transformer winding failure;
- Poor oil quality due to the accumulation of carbon particles can result in an internal flashover, which is expensive and requires several weeks to repair; and
- Mechanisms can develop mechanical defects leading to out-of-step (OOS) faults. Preventive maintenance has significantly improved the reliability of oil-immersed tap changers.

Common tap-changer fault types

The most common type of fault associated with tap changers is an OOS. This occurs when the voltage tap of one of the transformers in a bank is not synchronised with the others. When this occurs, the OOS relay trips the supply to the tap-changing control circuit to:

- reduce the risk of transformer overheating due to circulating currents; and
- prevent abnormal voltage excursions on the zone substation bus.

An OOS problem does not result in loss of customer supply, but it does require diagnosis from operating and test personnel to address the problem. One of the following faulty components generally causes OOS alarms:

- brake mechanisms;
- raise and lower contactors;
- OOS relays;
- voltage regulating relays;
- maintaining switches; and
- auxiliary switches.

A significant reduction in the incidence of OOS problems has been achieved via the regular refurbishment and replacement of aged and defective components

Winding temperature indicators

Winding temperature indicators are devices that effectively model the winding temperature. Winding temperature indicators also need to be as accurate as possibly, because they dictate transformer loading decisions, given the limits placed on a transformer's winding temperatures determine its overload capacity.

Specific winding temperature indicator issues include:

- Indicators fitted to transformers before the mid 1970's have up to a 15°C margin of error;
- The outputs from the indicators generate alarms via the SCADA system in the network control room; and
- Incorrect temperature indication can result in the transformers being over- or under loaded.

Station service transformers

Station service transformers are visually inspected as part the monthly inspection regime and the annual engineering audit.

Station service isolating transformers are connected to the LV reticulation network. To ensure the reliability of station LV supplies, it is now standard practice to have two 22 kV/415 V station service transformers with an LV auto change-over scheme.

Neutral earthing resistors

NER maintenance occurs every four years. This involves a close inspection for defects such as cracked resistor welds and insulation contamination. Testing is limited to:

- contact resistance;
- NER total resistance; and
- insulation resistance measurements.

The insulator surfaces are also cleaned to avoid flashovers due to dust accumulating and combining with moisture in the air. Maintenance intervals will be adjusted due to environmental conditions as required.

Rapid Earth Fault Current Limiter (REFCL)

REFCL maintenance occurs every two years, to perform detailed inspections of the neutral reactor including functional testing of the reactor motor drive unit.

Annual engineering and monthly inspections by operators will also take place to identify defects such as cracked insulator, oil levels, oil leaks, operating temperatures, breather and reactor tank condition.

7.3 APPENDIX C – ESTIMATING TRANSFORMER DEGREE OF POLYMERISATION VALUES

A power transformer contains a significant amount of paper insulation and its condition varies. Deterioration is at its highest where temperatures are highest, and this occurs within the transformer windings, which is not accessible. As a result, where a transformer is in service the condition within the winding can only be estimated.

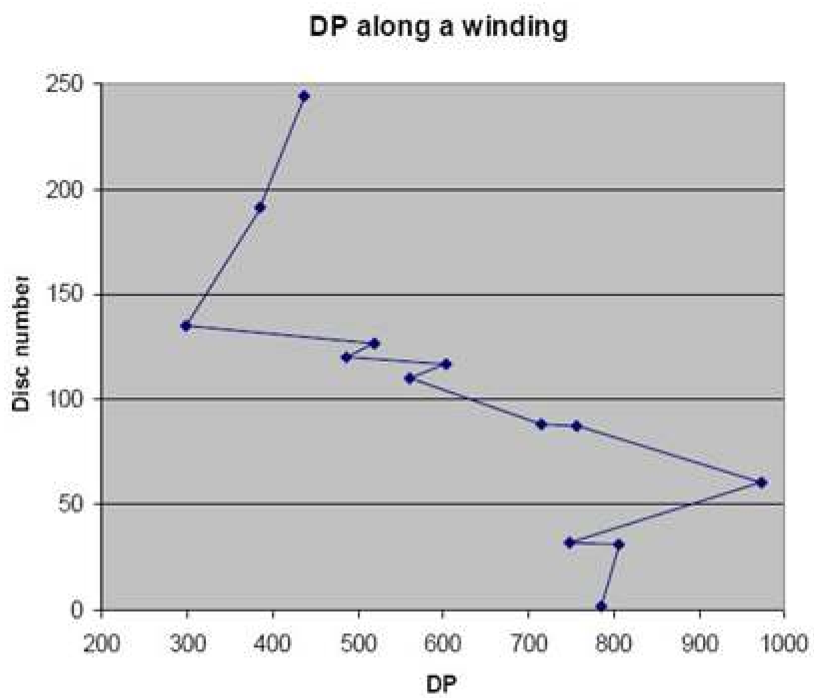
Diagnostic testing and historical data are the only means available to determine the condition of the transformer deep within the insulation structure without dismantling the unit.

Figure 7–2 shows the results from paper sample Degree of Polymerisation (DP) measurements taken from taken from different positions along the height of the winding of a dismantled transformer.

The DP value can vary significantly within a transformer:

- The hottest part of the transformer—the middle of the winding—exhibits the lowest DP value.
- The insulation at the base of the transformer remains cool for most of its life and typically suffers little degradation.

Figure 7–2: Degree of Polymerisation throughout a transformer winding



Furan analysis

The DP can be assessed by either a:

- Furan analysis of the transformer oil, or
- direct paper sample measurements.

Furan analysis involves oil sample testing for the presence of the products of cellulose decay in a transformer. These tests can be undertaken routinely as part of the annual oil sample program and the DP values monitored and trended. However, the furan level should only be used as an indicator across a population to determine the transformers that have aged the most. Other testing is required to accurately determine the actual insulation condition of the transformers.

A direct paper sample is taken from a main transformer's windings and leads for DP testing whenever an opportunity arises.

Comparison of DP estimation methods

Jemena refurbished a number of transformers on the United Energy Distribution Network over the period between 2007 and 2010, and a large number of paper samples were taken. **Table 7-2** shows a summary of the results and the different conditions within a power transformer.

Table 7-2: Summary of De-Tanked Transformer DP Values

Transformer[1,2]	DN #1	MTN #1	MTN #3	GW #3	MTN #2	RBD #1	RBD #3	Average
Average Lead	422	423	390	698	N/A	697	360	498
Average top winding	312	274	315	379	301	567	320	353
Furan-derived DP reading	613	645	661	636	683	677	645	651
Difference - lead and winding	111	148	75	319	N/A	130	40	137
Furan DP: winding DP ratio	1.97	2.35	2.10	1.68	2.27	1.19	2.02	1.94

1. Paper samples were collected from both the HV winding and the HV leads as these parts of the transformer structure are easily accessible.
2. Furan-derived DP readings were taken from 2007 DGA tests (earliest available).

Observations resulting from this testing include the following:

- On average, the estimated DP derived from furan levels is approximately twice that of the actual paper sample within the transformer winding;
- The average difference between the paper sample from the centre of the winding and the paper sample at the top of the winding (winding lead) is over 130DP;
- The lowest DP value of the insulation should be used as the overall condition measure of the transformer;
- Where the insulation is of the lowest strength will be the location with the highest likelihood of being the point of failure; and
- The insulation condition deep within the winding of an aged transformer is at least 100DP worse than the insulation at the top of the winding.

Transformer moisture content by PDC and RVM

Polarisation and Depolarisation Current (PDC) and Recovery Voltage Measurements (RVM) are measurements of the dielectric response of a transformer's insulation system, which can be interpreted to give accurate transformer insulation system:

- moisture content assessments, and
- average DP value estimates.

A transformer's moisture content is a significant indicator of the transformer's condition and a major contributor to the rate of ageing of the paper insulation. PDC and RVM tests are an accurate measure of paper insulation condition and can be used to determine a transformer's end-of-life.

PDC and RVM testing is carried out so that in time all transformers are tested:

- once they reach the age of 45 years to assist with end-of-life prediction, and
- as required, to assist with the refinement of the retirement/replacement decision.

Test accuracy

The value of the test lies in the accuracy of the moisture assessment and in the close correlation achieved between the assessed average DP and the paper sampling result.

The test is more accurate than estimating the DP values from oil sample furan analysis, which tends to overestimate the actual value.

PDC and RVM testing has been scheduled to be performed on five transformers each year.

About paper samples

The ultimate determination of a transformer's condition derives from remove a section of paper from the transformer winding for testing for its actual DP value, which is expensive and difficult to perform.

It is not possible to obtain paper samples from within the winding, which provide the true measure of the poorest DP condition. As a proxy, paper samples are taken from leads (end of the winding), which age at a lower rate and so are in a better condition than the winding.

Estimating winding condition from winding lead results

The data collected over the past decade has led to the development of the following rules, which are applied to the winding lead result and other non-invasive test results to estimate the condition within the winding:

- The DP value of the winding lead of an aged transformer is on average at least 100DP higher than the DP value in the winding. The DP value of the neutral lead of an aged transformer is at least 200DP higher than the DP value of the winding;
- Comparisons between the furan-derived DP and paper samples show that the figure (based on 2-FAL count) overestimates the condition of the transformer by approximately 300DP for an aged transformer; and
- The correlation between the results of PDC/RVM and furan-derived DP levels is that the PDC/RVM test result is around 250DP lower than the furan-derived DP level.

There are still margins of error within these tests, and it is not possible to determine the single worst DP value in the transformer to determine its exact timing without deconstructing the transformer. However, these estimates are likely to be conservative, and a true condition of a transformer may be worse than the condition assigned by applying these rules.

7.4 APPENDIX D – ASSET RISKS AND ISSUES

Other asset risks and issues include excessive noise and noise reduction, oil containment, Copper Sulphide corrosion and Polychlorinated biphenyl (PCB) contamination.

Noise reduction

Power transformers at zone substations create more noise at peak load periods and additional noise from cooling fan operation. While new zone substations are constructed so that noise is kept within allowable limits, older substations may not comply and noise attenuation measures may be required.

Non-complying zone substations

If a complaint is referred to the Environment Protection Agency (EPA) and a zone substation is found to be non-compliant, noise reduction works may be enforced.

Zone substation noise attenuation to the level required by regulation may cost in the order of $750,000.

New zone substation compliance

New zone substations will meet the requirements of the EPA regulations. Prior to construction, measurements of the background noise levels are taken and recorded. Noise limits are specified for major plant items to minimise noise levels (particularly transformers).

After construction and energisation, noise level measurements are taken for compliance. Generally, transformer noise containment enclosures or low noise transformers will be required where there is housing nearby.

Oil containment

Zone substation transformers typically contain 16,000 litres of insulating oil.

Action has been taken to reduce the risk of oil escaping, particularly through the construction of bunds for all power transformers.

A major escape of oil from a zone substation could result in significant clean-up costs and lead to prosecution by the EPA.

Oil leak prevention measures

While oil spill kits are stored at zone substations to address minor leaks, the effect of a spill can be minimised but not eliminated.

The preferred method to prevent further leakage into the ground includes:

- installing Humeceptor pits (or recommissioning the existing triple interceptor pits), and
- sealing the bunded areas around the transformers.

Copper Sulphide

Table 7-3 lists the zone substations where transformer oil testing has identified potentially corrosive sulphur in the transformer oil. Further investigation into other transformer types (for example, instrument transformers) is required, and the phenomenon may affect other oil-filled HV plant. Monitoring of the annual DGA results for indicators of corrosive sulphur effect is necessary to prioritise further testing.

Table 7-3: Copper Sulphide Positive Transformers

Zone Substation	Transformer	Potentially Corrosive
Broadmeadows (BD)	No.4	Positive

Zone Substation	Transformer	Potentially Corrosive
Coolaroo (COO)	No.1	Positive
East Preston (EP)	No.2	Positive
Melbourne Airport (MAT)	No.1 and No.3	Positive
North Heidelberg (NH)	No.3	Positive
Sunbury (SBY)	No.1 and No.3	Positive

Copper Sulphide risk

The International Council on Large Electrical Systems (CIGRE) set up a working group in 2005 to investigate the formation of copper sulphide (Cu_2S) in transformer insulation. It is estimated that there have been 100 (large) unit failures from Cu_2S since the year 2000 around the world (except Japan).

Reaction process

It is believed the reaction is a two-stage process resulting in the following effects:

- Corrosive sulphurs react with bare copper to form complexes (containing copper and a disulphide);
- Reactive complexes decompose to form Copper Sulphide (Cu2S);
- Cu2S deposits form on conductors and paper insulation (Copper Sulphides are conductive and migration into the insulating medium can lead to localised electrical stress and heating); and
- Switching transients and impulses weaken the insulation, leading to failure.

The presence of sulphur does not mean the transformer will fail immediately, and enamelled copper is unaffected, however any insulation damage is irreversible.

Like most chemical reactions, heat increases the reaction rate. Oxygen is also necessary and is consumed during the reaction. DGA tests show a reduction (‘consumption’) of oxygen content and elevated levels of ethane and methane when copper sulphide is present.

Corrective action

Passivators have been added to all the affected Jemena transformers to stop the reaction. Japan has been using passivated oils since the 1970s.

PCB contamination

Polychlorinated biphenyls (PCB’s) were used as an insulating liquid in electrical systems over a number of years, particularly in capacitors. PCB’s represent an environmental risk and are carcinogenic. Before these risks were identified, some power transformer diverter switches and distribution transformers were contaminated with small quantities of PCB’s.

Decontamination efforts

Significant effort has gone into the identification and removal where practical of all PCB contaminated transformer oil. Although no JEN transformer was PCB filled, some contamination was found, deriving from common oil handling equipment used during the manufacturing process and later for maintenance work.

Zone substation testing and identification

PCB contamination is categorised as:

- scheduled (greater than 50 parts per million, or
- non-scheduled (greater than 2 and less than 50 parts per million).

All power transformers have now been tested for PCB contamination, with four transformers testing positive for low concentrations.

All transformers and OLTC diverter switches will be fitted with labels to identify the oil's PCB content, where a:

- green label identifies less than 2 parts per million;
- yellow label identifies greater than 2 and less than 50 parts per million; and
- red label identifies greater than 50 parts per million.

Handling procedures

Affected transformers have been affixed with warning signs. If internal oil work is required, special tankers will be used to ensure the PCB will not be transferred to other equipment. When the transformers are to be refurbished or if oil in the transformer main tanks is to be reconditioned, the oil will be managed in accordance with established procedures.

The Ferranti ES3 type tap changers also incorporated capacitors containing PCB in the tap-changer mechanism cubicle. In 1997, 35 ES3 tap changers were known to have these capacitors, fifteen of which leaked and contaminated the oil in the tap changer compartment. All capacitors in the tap changers were removed, the contaminated oils were replaced, and the residual PCB was assessed and found to be below the threshold level of contamination.

7.5 APPENDIX E – TRANSFORMER CONDITION HEALTH INDEX TABULATION

JEN Transformer Health Index

Legend	PDC/RVM Test Results PDC/RVM: DP Estimate (± 25)	PDC/RVM Test Results Paper Moisture(%) (@25°C)	Oil Test Results Furan: DP Estimate	Paper Sample Paper DP (Paper Sample)	Test Date Test Date	PDC/RVM Test Results Oil Conductivity (S/m)	Oil Test Results Oil Quality	Oil Test Results Moisture in Oil# (ppm)	Oil Test Results Acidity in Oil# (mgKOH/g)	Oil Test Results DGA	Oil Test Results Dielectric	Oil Test Results Inter Facial Tention (IFT)	Oil Test Results Copper Sulphide (Cu2S)	Bushing Make	OIP Bushing Test Results C1% PF at 10kV R Ph	OIP Bushing Test Results C1% PF at 10kV W Ph	OIP Bushing Test Results C1% PF at 10kV B Ph
Good	>400	<1%	>400	>400			Good	<20	<0.05	✓	>50	>30	No	OIP	<0.7	<0.7	<0.7
														RBP	<1	<1	<1
Test, Evaluate & Monitor	250-400	1% - 3%	250-400	300-400			Fair	20-30	0.05-0.2	?	30-50	20-30		OIP	-	-	-
														RBP	1-1.5	1-1.5	1-1.5
Initiate Life Extension Program or Replacement	<250	>3%	<250	<300			Poor	>35	>0.2	X	<30	<20	Yes	OIP	>0.7	>0.7	>0.7
														RBP	>1.5	>1.5	>1.5

Transformer	Zone Substation	Manufacturer	Year of Manufacturer	PDC/RVM Test Date	Paper Condition PDC/RVM: DP Estimate (± 25)	Paper Condition Paper Moisture(%) (@25°C)	Paper Condition Furan: DP Estimate	Paper Condition Paper DP (Paper Sample)	Oil Condition Test Date (DGA)	Oil Condition Oil Conductivity (S/m)	Oil Condition Oil Quality (Using DGA and PDC/RVM results)	Oil Condition Moisture in Oil# (ppm)	Oil Condition Acidity in Oil# (mgKOH/g)	Oil Condition DGA	Oil Condition Dielectric	Oil Condition Inter Facial Tension (IFT)	Oil Condition Copper Sulphide (Cu2S)	Bushing Condition Bushing Make	Bushing Condition C1% PF at 10kV R Ph	Bushing Condition C1% PF at 10kV W Ph	Bushing Condition C1% PF at 10kV B Ph	Bushing Condition Bushing Test Date
No.1	AW	A.E.I.	1966	May-12	495	3.2	588	-	20/05/2015	2.89×10^{-12} (@25°C)	Fair	16	0.06	✓	58	23.9	No	RBP	0.942	1.041	1.141	27/03/2013
No.2	AW	W.E.T.	1981	May-12	535	2.0	622	-	20/05/2015	2.07×10^{-12} (@25°C)	Fair	21	0.03	✓	47	25.2	No	RBP	0.353	0.349	0.322	23/11/2010
No.3	AW	A.E.I.	1966	May-11	480	3.2	503	-	23/06/2016	3.47×10^{-12} (@25°C)	Fair	15	0.11	✓	89	20	No	RBP	0.937	0.865	1.187	13/06/2012
No.4	AW	W.E.T.	1988	-	-	-	688	-	20/05/2015	-	Good	5	0.01	✓	76	35.1	No	OIP	0.555	0.539	0.615	31/07/2008
No.1	BD	English Electric	1973	May-10	530	1.3	541	-	16/03/2016	1.66×10^{-12} (@25°C)	Good	13	0.02	✓	67	31	No	OIP	0.603	0.593	0.589	30/05/2008
No.2	BD	English Electric	1968	-	-	-	548	237	16/03/2016	-	Good	14	0.02	✓	49	29	No	OIP	0.857	0.869	0.796	11/07/2010
No.3	BD	English Electric	1968	-	-	-	562	-	16/03/2016	-	Good	16	0.03	✓	37	28	No	OIP	0.86	0.894	0.889	11/07/2010
No.4	BD	Wilson	2002	-	-	-	688	-	16/03/2016	-	Good	5	0.01	✓	66	37	Yes	OIP	0.466	0.464	0.476	3/12/2010
No.1	BMS	ABB	2015		-	-	700	-	3/06/2016		Good	5	0.02	✓	99	40	No					
No.2	BMS	ABB	2015		-	-	700	-	3/06/2016		Good	5	0.01	✓	96	39	No					
No.1	BY	A.E.I.	1967	Apr-13	480	1.2	572	700	16/03/2016	1.99×10^{-12} (@25°C)	Good	16	0.01	✓	38	40	No	RBP	1.156	1.212	0.981	26/03/2013
No.2	BY	ABB	2006	-	-	-	688	990	16/03/2016	-	Good	5	0.01	✓	70	42	No	-	-	-	-	-
No.1	CN	A.E.I.	1967	May-10	370	3.9	477	-	16/03/2016	4.56×10^{-12} (@25°C)	Fair	23	0.13	✓	60	19	No	RBP	0.357	0.356	0.357	30/05/2013
No.2	CN	A.E.I.	1967	May-12	445	3.0	551	-	16/03/2016	2.37×10^{-12} (@25°C)	Poor	27	0.09	✓	51	20	No	RBP	0.377	0.357	0.365	6/06/2013
No.3	CN	WILSON	1990	-	-	-	694	-	16/03/2016	-	Good	10	0.01	✓	82	41	No	OIP	0.439	0.415	0.434	30/11/2010
No.1	COO	WILSON	2007	-	-	-	700	-	26/02/2016	-	Good	5	0.01	✓	67	37	Yes	-	-	-	-	-
No.2	COO	WILSON	2012	-	-	-	700	-	26/02/2016	-	Good	5	0.01	✓	81	37	No	-	-	-	-	-
No.1	CS	TYREE	1976	May-13	550	1.1	677	-	10/03/2016	1.8×10^{-12} (@25°C)	Good	11	0.01	✓	67	29	No	RBP	0.488	0.476	0.548	15/11/2010
No.2	CS	WILSON	1976	May-13	520	1.0	688	-	10/03/2016	1.81×10^{-12} (@25°C)	Good	10	0.01	✓	60	28	No	RBP	0.449	0.37	0.388	15/11/2010
No.1	EP	WILSON	1963	May-13	440	2.6	645	-	11/03/2016	2.25×10^{-12} (@25°C)	Fair	23	0.07	✓	47	21	No	RBP	0.923	0.633	0.924	5/08/2008
No.2	EP	ABB	2006	-	-	-	700	-	11/03/2016	-	Good	5	0.01	✓	76	35	Yes	-	-	-	-	-
No.3	EP	GEC/MV	1959	-	-	-	562	-	11/03/2016	-	Fair	35	0.01	✓	51	31	No	RBP	0.684	0.686	0.691	9/12/2010
No.4	EP	ENGLISH ELECTRIC	1958	-	-	-	641	-	11/03/2016	-	Good	31	0.03	✓	49	29	No	RBP	0.408	0.449	0.481	8/05/2013
No.1	ES	WILSON	1965	May-09	255	3.7	613	410	21/12/2015	4.27×10^{-12} (@25°C)	Fair	23	0.04	✓	47	27.5	No	RBP	1.147	1.09	0.925	22/03/2013
No.2	ES	WILSON	1965	May-09	250	3.6	592	360	21/12/2015	4.19×10^{-12} (@25°C)	Fair	20	0.04	✓	40	26.4	No	RBP	0.952	0.983	0.943	11/11/2010
No.1	FE	WILSON	2010	-	-	-	700	-	10/03/2016	-	Good	5	0.01	✓	78	40	No	-	-	-	-	-
No.2	FE	AEI	1967	-	-	-	604	-	10/03/2016	-	Good	19	0.01	✓	38	38	No	RBP	0.852	0.871	0.831	20/12/2010
No.1	FF	E.E.	1955	-	-	-	441	220	14/04/2016	-	Poor	23	0.2	✓	41	17	No	-	-	-	-	-
No.2	FF	E.E.	1960	May-10	430	2.4	473	230	23/09/2016	2.16×10^{-12} (@25°C)	Fair	18	0.07	✓	57	21	No	-	-	-	-	-
No.3	FF	E.E.	1960	-	-	-	514	250	11/03/2016	-	Poor	31	0.1	✓	54	21	No	-	-	-	-	-
Spare	FF	N/A	-	-	-	-	-	-	13/04/2015	-	Good	18	-	✓	59	-	No	-	-	-	-	-
No.1	FT	WILSON	1970	-	-	-	677	-	11/03/2016	-	Fair	26	0.03	✓	42	24	No	RBP	0.543	0.539	0.551	16/12/2010
No.2	FT	WILSON	1970	-	-	-	677	-	30/03/2015	-	Fair	20	0.03	✓	67	24	No	RBP	0.497	0.5	0.499	16/11/2010
No.1	FW	A.E.I.	1966	May-13	435	2	617	-	10/03/2016	1.98×10^{-12} (@25°C)	Good	26	0.02	✓	39	30	No	RBP	0.726	0.676	0.645	16/12/2010
No.2	FW	A.E.I.	1966	May-13	380	2.2	622	-	10/03/2016	1.83×10^{-12} (@25°C)	Good	25	0.03	✓	30	28	No	RBP	0.947	0.947	0.997	16/12/2010
No.3	FW	E.E.	1971	May-11	365	1.6	555	-	10/03/2016	3.54×10^{-12} (@25°C)	Fair	9	0.11	✓	58	20	No	-	0.471	0.432	0.432	31/05/2013
No.1	HB	W.E.T.	1966	May-11	230	4.9	666	260	26/02/2016	7.73×10^{-12} (@25°C)	Good	19	0.02	✓	30	31	No	RBP	0.994	0.64	1.029	16/02/2012
No.3	HB	W.E.T.	1966	May-14	295	2.8	661	500	26/02/2016	3.44×10^{-12} (@25°C)	Good	21	0.02	✓	37	32	No	RBP	0.99	0.88	0.952	17/02/2012
No.1	MAT	WILSON	2002				694		16/03/2016		Good	5	0.01	✓	65	38						
No.2	MAT	WILSON	2002				694		16/03/2016		Good	5	0.01	✓	88	38						
No.3	MAT	WILSON	2015																			
No.1	NH	TYREE	1973	-	-	-	683	-	10/03/2016	-	Good	17	0.01	✓	65	29	No	RBP	0.402	0.363	0.72	17/11/2010
No.2	NH	TYREE	1973	-	-	-	683	-	27/03/2015	-	Good	8	0.01	✓	73	28.9	No	RBP	0.446	0.488	0.411	17/11/2010
No.3	NH	WILSON	2005	-	-	-	700	-	10/03/2016	-	Good	5	0.01	✓	55	35	Yes	-	0.474	0.466	0.469	7/05/2013
No.1	NS	A.E.I.	1957	-	-	-	584	260	3/06/2016	-	Fair	15	0.07	✓	36	24	No	-	-	-	-	-
No.2	NS	A.E.I.	1957	May-10	480	2.3	532	390	3/06/2016	1.85×10^{-12} (@25°C)	Fair	17	0.03	✓	53	26	No	-	-	-	-	-
No.3	NS	A.E.I.	1956	-	-	-	569	250	3/06/2016	-	Fair	12	0.07	✓	59	23	No	-	-	-	-	-
No.1	NT	E.E.	1949	May-12	450	1.8	517	520	10/03/2016	3.08×10^{-12} (@25°C)	Fair	32	0.05	✓	31	33	No	-	-	-	-	-
No.3	NT	E.E.	1949	May-12	375	2.3	541	-	30/03/2015	4.17×10^{-12} (@25°C)	Fair	34	0.06	✓	43	33	No	RBP	0.507	0.632	0.703	21/12/2010
No.1	P	J&P	1958	-	-	-	588	-	11/03/2016	-	Fair	31	0.02	✓	33	31	No	RBP	0.71	0.575	0.686	29/10/2008
No.1 Reactor	P	A.E.I.	1958	-	-	-	694	-	4/05/2016	-	Good	16	0.02	✓	77	28						
No.2	P	J&P	1958	-	-	-	466	-	11/03/2016	-	Poor	33	0.23	✓	35	17	No	RBP	0.745	0.689	0.796	30/10/2008
No.2 Reactor	P	A.E.I.	1957	-	-	-	688	-	4/05/2016	-	Good	13	0.02	✓	66	30						
No.1	PV	BRYCE	2011	-	-	-	700	-	26/02/2016	-	Good	5	0.01	✓	85	35	No	RBP	0.704	0.674	0.706	7/10/2010
No.2	PV	WILSON	2012	-	-	-	700	-	26/02/2016	-	Good	5	0.01	✓	85	38	No	RBP	0.792	1.178	0.732	6/10/2010
No.3	PV	BRYCE	1964	May-10	320	2.9	555	-	26/02/2016	5.08×10^{-12} (@25°C)	Good	19	0.05	✓	36	25	No	RBP	0.919	0.827	0.872	4/10/2010
No.1	SBY	WILSON	2002	-	-	-	677	-	11/03/2016	-	Fair	7	0.01	✓	85	27	Yes	OIP	0.534	0.55	0.587	14/03/2010
No.2	SBY	A.G.E.	1977	May-11	540	1.9	636	-	11/03/2016	1.78×10^{-12} (@25°C)	Fair	29	0.04	✓	50	25.0	No	RBP	0.978	0.935	0.816	14/03/2010
No.3	SBY	WILSON	2000	-	-	-	688	-	11/03/2016	-	Good	20	0.01	✓	39	35	Yes	OIP	0.516	0.505	0.492	23/10/2008
No.1	SHM	ABB	2008	-	-	-	700	-	11/03/2016	-	Good	5	0.01	✓	63	39	No	-	-	-	-	-
No.2	SHM	WILSON	2010	-	-	-	700	-	11/03/2016	-	Good	5	0.01	✓	69	40	No	-	-	-	-	-
No.1	ST	WILSON	1985	-	-	-	661	-	9/03/2016	-	Fair	15	0.02	✓	42	28	No	RBP	0.469	0.475	0.515	29/08/2010
No.2	ST	WILSON	1985	-	-	-	677	-	9/03/2016	-	Good	17	0.01	✓	72	30	No	RBP	0.506	0.491	0.505	29/08/2010
No.3	ST	WILSON	1996	-	-	-	508	-	9/03/2016	1	Fair	15	0.06	✓	71	21	No	OIP	0.445	0.445	0.38	29/08/2010
No.1	TMA	ABB	2014		-	-	-	-														
No.2	TMA	ABB	2014		-	-	-	-														
No.1	TH	W.E.T.	1984	-	-	-	700	-	13/10/2015	-	Fair	14	0.02	✓	57	26.1	No	RBP	0.499	0.493	0.489	18/11/2010
No.2	TH	W.E.T.	1984	-	-	-	700	-	28/10/2015	-	Good	17	0.05	✓	70	20.7	No	RBP	0.51	0.465	0.487	18/11/2010
No.1	YVE	WILSON	2013	-	-	-	700	-	8/10/2014	-	Good	5	0.01	✓	68	40	No	-	-	-	-	-
No.2	YVE	WILSON	2013	-	-	-	700	-	8/10/2014	-	Good	5	0.01	✓	78	36.9	No	-	-	-	-	-
No.4	YVE	WILSON	2000	-	-	-	700	-	27/03/2015	-	Good	5	0.01	✓	93	34.7			0.478	0.509	0.532	15/12/2010

7.6 APPENDIX F – TRANSFORMER CYCLIC RATINGS

LCR	Limited Cyclic Rating
C	Cyclic Rating
NP	Name Plate Naming

ZS Station	No. of Tx	No.1 Tx Rating (MVA)			Tx CB	No.2 Tx Rating (MVA)			Tx CB	No.3 Tx Rating (MVA)			Tx CB	No.4 Tx Rating (MVA)			Tx CB
		LCR	C	NP		LCR	C	NP		LCR	C	NP		LCR	C	NP	
AW	4	36	34	30	45.7	38	36	30	45.7	36	34	30	45.7	48.8	45.5	40	47.6
BY	2	37.4	34	30	47.6	42.9	39.6	33	47.6								
BD	4	40	38.9	30	45.7	40	38.9	30	45.7	40	38.9	30	45.7	42.9	39.6	33	76.2
BMS	2	45	42	33	47.6	45	42	33	47.6								
CN	3	41.3	37.2	30	45.7	41.3	37.2	30	45.7	42.9	39.6	33	47.6				
CS	2	44	40	33	45.7	44	40	33	45.7								
COO	2	42.9	39.6	33	47.6	45	42	33	47.6								
EPN	1	45	42	33	76.2												
EP A	1&3	32	30	27		18	17	13									
EP B	2&4	32	30	27		18	17	13									
ES	2	36	36	27	47.6	36	36	27	47.6								
FF	3	15.6	14.5	13.5	28.5	15.6	14.5	13.5	28.5	15.6	14.5	13.5	28.5				
FT	2	36	33	30	30.5	36	33	30	30.5								
FE	2	45	42	33	30.5	37.4	34	30	30.5								
FW	3	36	33	30	45.7	36	33	30	45.7		36	30	45.7				
HB	2	32.4	32.4	30	47.6	32.4	32.4	30	47.6								
NT	2	41	41	38	76.2	41	41	38	76.2								
NS	3	15.4	14	13.5	47.6	14.7	13.4	13.5	47.6	14.5	13.2	13.5	47.6				
NH	3	39.1	37.6	30	45.7	39.1	37.6	30	45.7	39.1	37.6	30	45.7				
PV	3	45	42	33	47.6	45	42	33	47.6	15	13	10	47.6				
P	2	26.2	20.3	20	13.7	26.2	20.3	20	13.7								
ST	3	38	38	33	47.6	38	38	33	47.6	38	38	33	47.6				
SBY	3	21	19.5	16	30.5	13.4	12.8	10	19.3	21	19.5	16	30.5				
SHM	2	45	42	33	47.6	45	42	33	47.6								
TH	2	49.5	49.5	45	47.6	49.5	49.5	45	47.6								
TMA	2	45	42	33	47.6	45	42	33	47.6								
YVE	2	45	42	33	76.2	45	42	33	76.2								

7.7 APPENDIX G – BUNDING STATUS

Sub	Oil Containment	Notes
AW - Airport West	Yes	
BD - Broadmeadows	Yes	
BMS - Broadmeadows South	Yes	
BY - Braybrook	No	A triple interceptor pit was installed when the second transformer project was completed. The need for a Humeceptor is to be evaluated.
CN - Coburg North	Yes	
COO - Coolaroo	Yes	
CS - Coburg South	No	Part of the switchgear upgrade project in 2024. Merri creek approx. 2km away.
EP - East Preston	No	Bunding & Humeceptor will be part of the rebuild in 2021/22
EPN - East Preston	Yes	
ES - Essendon	No	Part of the transformer replacement project in 2019. Yarra river approx. 2km away.
FE - Footscray East	Yes	
FF - Fairfield	No	Part of the transformer replacement project in 2018/19. Yarra river approx. 2km away.
FT - Flemington	No	Part of the 3rd transformer project.
FW - Footscray West	Yes	
HB - Heidelberg	Yes	
NH - North Heidelberg	Yes	
NS - North Essendon	Yes	
NT - Newport	Yes	
P - Preston	-	Bunding & Humeceptor will be part of the station rebuild in 2019.
PV - Pascoe Vale	Yes	
SBY - Sunbury	No	Bunding & Humeceptor will be part of the rebuild in 2018/19
SHM - Sydenham	Yes	
ST - Somerton	No	2019 Project.
TH - Tottenham	Yes	
TMA - Tullamarine	Yes	
YVE - Yarraville	Yes	

7.8 APPENDIX H – ZSS ROOF CONDITION

ZSS	Roof Condition	Initial Action	Comments	Action - 19/08/2015	Progress - 16/06/2016
NS	East metal deck- Significant surface rust - refer photo	Do nothing – 11kV Switch Room building roof will be replaced as part of 2016/17 Transformer Replacement Project.	**Priority 1:** Require a quote to replace 8m of flashing on the south-East end of the roof. Also repair 8m of roofing on the North –East end of the roof. See Rob for details.	Complete ASAP in 2015 - first priority. Ensure that no water is leaking onto the switchgear. Replace the roof in 2016 as part of the transformer project - Simon to get a price from Daniel Lau. In NS SoW.	
NT	Significant moss growing on roof. No visible signs of leaks.	Remove moss and clean roof (using high-pressure cleaner).	**Priority 2:** Quote to Remove 3 sections of ridge capping. Clean all dirt and rubbish out. Install new ridge capping if the old one cannot be re installed.	PO created and work scheduled for 13-14 October. Works completed: 1. 3 sections of ridge capping removed. 2. All dirt, leaves etc cleaned from under ridge capping. 3. All 3 ridge cappings replaced with new over sized ridge capping.	Work completed 13-14 October 2015. PM Order 5136021.
EP	Paint flaking off all over the roof	Repaint the roof as the switch room will remain in service until 2021/22.	**Priority 3:** **Switch House A:** Repair rust on roofing sheets - eves at west end. Replace rusted gutter at West end. Go over whole roof sheets and replace loose nails with roofing screws. Spot treat rust spots. **Switch House B:** Spot treat rust spots with rust paint – there's not many rust spots. Re silicon 2 roof wind fans to stop leaks. Push out dent in one roof sheet.	Action as per quote. Speak to Darren Trafford as he is managing the EP site. Complete in 2015.	
ES	Old roof has surface rust over majority of surface. Suggest painting roof to prolong life span of sheets.	Treat surface rust by painting.	**Priority 4:** **Quote 1:** repaint entire roof with Rust Grip paint as you have recommended. Can you provide some documentation or specs on the paint please. **Quote 2 :** repaint entire roof with a locally available exterior grade rust inhibiting paint.	Repaint roof as per quote. Complete in 2015. Need to update the ACS Buildings & Grounds to include the condition of the roof and the issue for each ZSS. Need a BC to replace the roof in the near future - could be as part of the transformer replacement project? Check scope. Decided to wait until transformer project in 2018/19 and replace for an estimated $35k (estimate from James Michael). Roof expected to last next 4 years. Monitor.	Continue to monitor condition until replacement in 2018/19.
BD	Surface rust in some areas	Do nothing – control building will be demolished as part of control building and relay replacement project in 2016.		Treat rust. Use a wire brush, kill rust and then apply rust protective paint. Explore market to find a suitable product.	
CN	Some surface rust on roof	Treat the surface rust. Building will be extended in 2018/19 to accommodate the relay upgrades.		Treat rust. Use a wire brush, kill rust and then apply rust protective paint. Explore market to find a suitable product.	
FT	Flashings and several areas on roof have surface rust.	Treat rust on roof and flashings to prolong life. Roof will be in-service until at least 2021.		Treat rust. Use a wire brush, kill rust and then apply rust protective paint. Explore market to find a suitable product. Replace capping where it is severely rusted, otherwise spot treat.	
PV	Significant surface rust on mess room roof	Replace the roof as the rust damage looks extensive.		Comms equipment inside. Add to ACS for roof replacement. Replace in 2016? Check budget and prioritise. Inspect annually.	Initiate a Gate 3 or do as part of minor capex works in 2016/17. Replaced in 2017
AW	Small amount of surface rust	Do nothing – control building will be demolished as part of control building and relay replacement project in 2016.		Need to revisit treating the roof if the project is deferred. To be reinspected annually. Add to Standard Job to inspect the condition of the roof, as part of gutters or static line inspection.	
FE	No evidence of corrosion/deterioration.	None. Roof to be replaced as part of switchgear replacement project in 2018/19?		No action required. Look at BC for FE to check if the roof needs to be replaced.	
FW	Surface rust covering roof area – suggest to paint with rust grip to prolong roof life. Gutters not rusted but needs painting on outside - existing paint peeling off.	Monitor roof condition to determine if action is required prior to roof replacement.		Check BC if it includes roof replacement. If so, monitor condition until project is completed.	
P				Revisit and take photos at P.	
TH	No evidence of corrosion/deterioration but dirt against flashing may cause problems in the future.	Remove dirt and clean roof (using high-pressure cleaner).		Cleaning to be scheduled. **CAUTION** - do not use pressure cleaner to avoid driving water under flashing into the switchroom.	
SSS gate	Pedestrian gate	The pedestrian gate can be opened via the internal Push Bar relatively easy with the use of a bar, stick etc. through the cyclone fencing. We need to amend this as it is a safety risk. Do you have any ideas how we can fix this issue (i.e. install sheets on the surrounding cyclone fencing so objects cannot be put through the fence to gain access to the push bar mechanism (although it will still be accessible from the top), a different type of emergency exit mechanism)?		Fixed.	
YVE	No evidence of corrosion/deterioration.	None.		No action required.	

7.9 APPENDIX I - CRITICAL SPARES ASSESSMENT

[redacted]

7.10 APPENDIX J - ASSET CRITICALITY ASSESSMENT WORKSHEET

ASSET CRITICALITY ASSESSMENT WORKSHEET

ASSET AND BACKGROUND INFORMATION	
Site Name	General
Asset Class	Primary Plant
Sub-Asset Class	All
Date of Original Assessment	15-May-18
Date of Last Review	19-Jul-18
Reviewed By (where applicable):	

Risk Ref. No.	Description of Asset or Asset Grouping	Description of Risk	Consequence Category (Operational, HSE, Reputation etc.)	Description of Consequences	Current Controls	Criticality Score	Criticality Rating
1	Zone Substation Transformer	The risk associated with failure of zone substation transformers i.e. fails to insulate and/or carry load, resulting in: • Injury • Plant damage • Environmental damage (oil spill)	Operational, HSE	Consequence: Health, Safety & Environment / Operational **Major** due to: • Potential loss of life to staff or contractor • Loss of electricity supply to >2% customers (6,500) > 24 hours	As per ACS	AC4	High
2	Zone Substation Grounds	Potential for unauthorised access within Jemena zone substations, resulting in trip hazards, equipment failure due to vandalism, initiation of fire and/or oil spill	Operational, HSE	**Major** due to: - total permanent disability (staff or contractors), multiple hospitalisations, permanent disability and/or life-threatening injuries affectic member(s) of the public - Loss of electricity supply to >2% customers (6,500) > 24 hours Likelihood: Rare due to lack of incidents occuring within the last 10 years within the JEN network	As per ACS	AC4	High
3	Disconnectors and Buses	The risk associated with the failure of disconnector and buses i(.e. fails to insulate, etc.) resulting in • Plant fails to insulate • Plant fails to open or close, High resistance connection • Catastrophic plant failure (Porcelain) • Plant rating (overload or under-rated)	Operational, HSE	**Major** due to: • Potential life threatening injury to staff, contractors or public • Loss of electricity supply to >2% of customers (6,500) > 24 hours Likelihood: Rare due to lack of incidents occurring within the last 10 years within the JEN network	As per ACS	AC4	High
4	Switchgear	The risk associated with the failure of switchgear i.e. operation malfunction or explosive failure, resulting in: • Injury • Plant damage • Environmental damage (oil spill) • Loss of supply • Financial impact varies based on consequence and can be between $200K	Operational, HSE	**Major** due to: • Potential loss of life to staff or contractor • Regulatory investigations or government review • Loss of electricity supply to >2% of customers (6,500) > 24 hours Likelihood: Rare due to lack of incidents occurring within the last 10 years within the JEN network.	As per ACS	AC4	High
5	Capacitor bank failure	The risk associated with failure of capacitor bank, resulting in: • Poor power factor and regulatory non-compliance • Explosion of capacitor unit and tank rupture, resulting in expulsion of porcelain fragments and shrapnel • Explosion of reactor unit and tank rupture, resulting in oil leak (may also contain PCB) and possible fire start	Operational, HSE	**Minor** due to: • General regulatory queries regarding supply quality • No violation, breaches, fines or penalties Likelihood: Likely due frequent loss of capacitor banks	As per ACS	AC1	Low
6	Instrument transformer failure	The risk associated with failure of instrument transformer, resulting in: • Failure to adhere to regulations or code requirements • Expulsion of porcelain fragments and shrapnel • Loss of oil and fire start	Operational, HSE	**Serious** due to: • Medical treatment injury or lost time injury (staff or contractors) • Loss of electricity supply to >1% customers (3,200) > 6 hours	As per ACS	AC2	Moderate
7	Zone Substation Earthing	The risk of electric shock to internal employees, contractors or the public caused by inadequate substation HV earthing system (i.e. high resistance earth, step & touch potential under fault conditions, non-operation of HV protection)	Operational, HSE	**Major** due to: - potential life-threatening injuries to staff, contractors or member(s) of the public - inability to detact earth faults preventing operation of HV protection systems 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

7.11 APPENDIX K – JEN ZONE SUBSTATION ADDRESS LIST

Sub	Type	Street	P/code	Suburb	Melway
AW - Airport West	O	Moore Rd, (Opposite house no. 71)	3042	Airport West	15 - K5
BD - Broadmeadows	O	Cnr Maffra St & Barrys Rd	3048	Coolaroo	7 - C3
BMS - Broadmeadows South	B	Lot 602, 2-22 Maygar Boulevard	3047	Broadmeadows	7 - C9
BY - Braybrook	B	Cnr Bosquet St & Mitchell St	3012	Maidstone	27 - H11
CN - Coburg North	O	Newlands Rd (North of Norfolk Crt)	3058	Coburg North	18 - A6
COO - Coolaroo	B	Zakwell Court , (north end of court)	3048	Coolaroo	180 - A9
CS - Coburg South	I	Cnr. Victoria St. & Hudson St	3058	Coburg	17 - G12
EP - East Preston	B	Cnr Swanston St. & Quinn St	3072	Preston	31 - C1
EPN - East Preston	B	Cnr Swanston St. & Quinn St	3072	Preston	31 - C1
ES - Essendon	B	Cnr Buckley St & Price St	3040	Essendon	28 - B4
FE - Footscray East	B	Somerville Rd (West of Hyde St)	3013	Yarraville	42 - C8
FF - Fairfield	B	Cnr Station St & McGregor St	3078	Fairfield	30 - K8
FT - Flemington	I	Cnr Smith St & Rankins St	3031	Flemington	2A - A3
FW - Footscray West	B	Sanderson St (East of Gent St)	3013	Yarraville	41 - G8
HB - Heidelberg	B	Yarra St (West of Dora St)	3084	Heidelberg	32 - B5
NH - North Heidelberg	I	Cnr McNamara St & Ruthven St	3085	Macleod West	20 - A9
NS - North Essendon	B	Cnr Moreland Rd & Jhonson St	3044	Pascoe Vale South	28 - K3
NT - Newport	I	Douglas Pde (North of Hobson St)	3015	Newport	56 - B4
PTN - Preston	B	Cnr Murray Rd & St Georges Rd	3072	Preston	18 - F11
PV - Pascoe Vale	B	Cnr Northumberland Rd & Arnold Crt	3044	Pascoe Vale	17 - A7
SBY - Sunbury	O	Horne St opposite Mitchell's Lane	3429	Sunbury	382 - C6
SHM - Sydenham	B	Victoria Road	3037	Sydenham	3 - A7

Sub	Type	Street	P/code	Suburb	Melway
ST - Somerton	I	Cnr Hume Hwy & Pattulos Lane	3062	Somerton	180 - D4
TH - Tottenham	B	Somerville Rd (Opposite McDonald Rd)	3012	Tottenham	41 - B6
TMA - Tullamarine	B	77 Keilor Park Dve	3043	Tullamarine	15 - D4
YVE - Yarraville	B	5 Globe Street	3013	Yarraville	42 - B10

HV Customer Substations with Jemena Assets Installed

Sub	Type	Street	P/code	Suburb	Melway
MAT - Melbourne Airport	B	Cnr South Centre Rd & Link Rd	3045	Melbourne Airport	5 - C11
SSS - Somerton Switching Station	O	O'Herns Rd	3062	Somerton	180 - F6
VCO - Visyboard Coolaroo	B	Visy Board Factory	3048	Coolaroo	180 - B10
NEI - Nilsens Electrical Industries	O	Sheehan Rd (North of Dougharty Rd)	3081	Heidelberg West	19 - F10

Types of ZSS:	
I	Indoor
O	Outdoor
B	Indoor Distribution Bus

7.12 APPENDIX L – CONDITION BASED RISK MANAGEMENT

CBRM inputs and outputs

Critical CBRM inputs include:

- the engineering knowledge and practical experience of the assets from within the asset owner;
- asset specification, history (faults, failures, generic experience, maintenance records), duty, environment, test and inspection results;
- understanding of degradation and failure modes, and
- experience of building CBRM models.

CBRM outputs include:

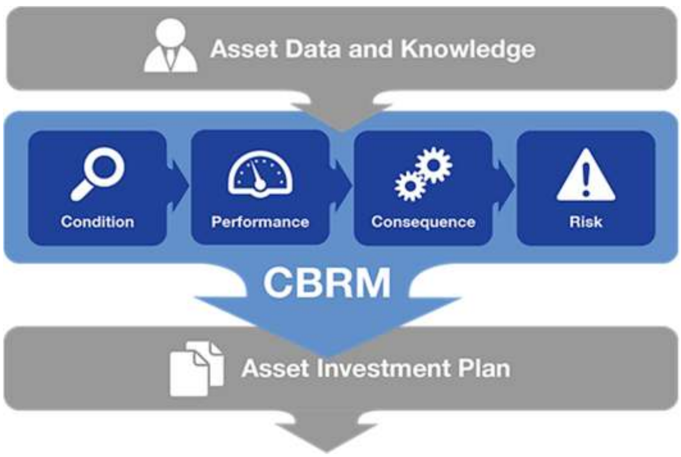
- Part 1 – Condition, which provides:
  - health indices, health index profiles, probability of failure (POF) and failure rates; and
  - estimates of future failure rates with different interventions.
- Part 2 – Risk, which provides:
  - quantification of current and future risk for asset groups with different interventions (expressed as a monetary value);
  - criticality, involving changes priority within an asset group; and
  - comparison/optimisation across asset groups.

CBRM procedures

Figure 7–3 shows an overview of the CBRM. The CBRM process followed by Jemena to develop the model was:

- Determine an asset health index (HI) and ageing rate for each power transformer;
- Determine the probability of failure for each power transformer;
- Determine the consequences of failure;
- Evaluate the associated financial risk, and
- Assess future scenarios and options

Figure 7–3: CBRM Overview



CBRM Health Index (HI)

The final Health Index (HI) profile for the asset class is calculated at year 0 (current year) and at any other arbitrary year in the future to determine the asset replacement volumes for each specific asset class. A maximum health index cap of 7 is assigned for every asset class to indicate the need of replacement. This is illustrated schematically in Figure 7–4 below.

Figure 7–4: Concept of Health Indices

Condition	**Health Index**	**Remnant Life**	**Probability of Failure**
Bad	10	At EOL (<5 years)	High
Poor		5 - 10 years	Medium
Fair		10 - 20 years	Low
Good	0	>20 years	Very low

The health index represents the extent of degradation as follows:

- Low values (in the range 0 to 4) represent some observable or detectable deterioration at an early stage. This may be considered as normal ageing, i.e. the difference between a new asset and one that has been in service for some time but is still in good condition. In such a condition, the PoF remains very low and the condition and PoF would not be expected to change significantly for some time.
- Medium values of health index, in the range 4 to 7, represent significant deterioration, with degradation processes starting to move from normal ageing to processes that potentially threaten failure. In this condition, the PoF, although still low, is just starting to rise and the rate of further degradation is increasing.

High values of health index (>7) represent serious deterioration; i.e. advanced degradation processes now reaching the point that they actually threaten failure. In this condition the PoF is now significantly raised and the rate of further degradation will be relatively rapid.

7.13 APPENDIX M - ASSET OBJECTIVES KPI ALIGNMENT

Business Objectives and Targets (by 2025)	ABS Policy Directives	ACS Objectives and KPIs	ACS Strategy to deliver ACS objectives	Performance Assessment
Safety Top quartile industry safety performance	• Never compromising employees', contractors' and the public's safety; • Apply the Jemena risk management approach; and • Facilitate continual improvement in asset safety and performance.	• Meet network service levels including safety indicators (annually): ○ No death or injury to a person (Alert Level: death or injury > 0) ○ No significant disruption to the community (Alert Level: major disruption > 0) ○ Primary Plant initiated fires (Alert Level: ZSS fires > 0) ○ Maintain public safety by maintaining ZSS physical security, visibility and warnings to public	For all assets in the asset class: • Asset Inspection, condition monitoring and maintenance • Asset replacement programs • For specific assets: • Transformer Oil and bushing condition monitoring • Indoor switchboard insulation condition monitoring • Thermal surveys of all ZSS electrical assets • Earth testing • Civil/structural surveys of buildings structures & civil assets	ACS objectives and KPIs are supported through establishment of: Polices and plans: • Incident Investigation Process • Electricity Safety Management Scheme (ESMS) • Analysis and reporting: • Asset performance monitoring • RIN reporting • ESV reporting • Incident investigation reporting • ESMS reporting • OHS&E reporting • Field auditing • ESV audit reports • Budget reporting • Performance review committees: • Asset performance monitoring • ESMS management • OHS&E • JCARS (Jemena Compliance and Risk System) • Jemena Portfolio Management Governance These policies, plans, reports and committees are used to assess the performance of the asset to support the delivery of the ACS Objectives and KPIs.
	• Comply with applicable law, regulations, codes and reporting requirements at all times.	• Comply with Electricity Distribution Code • Leverage F-factor scheme • Meet all of JEN's statutory obligations required under the Electricity Safety Act 1998 • ESMS regulation	• Management commitment for Jemena to meet all legal and regulatory obligations • Establishment of ESMS • Audit and compliance programs • Report any serious and other incidents according to the ESV reporting guidelines	
Performance Cost at or below regulatory allowance	Achieve annual targets for Customer reliability/responsiveness: • Unplanned System Average Interruption Duration Index (SAIDI) contribution target: 46.36 • Unplanned System Average Interruption Frequency Index (SAIFI) contribution target: 0.770	• Maintain network SAIDI, SAIFI, MAIFI annual targets (monitor monthly performance reports for asset failures) • Maintain the time taken to respond to faults/incidents (Average Dispatch Time, Average Onsite Time) • Complete incident investigations within 20 business days	• Identification and timely replacement of end-of-life assets • Monthly performance monitoring • Incident investigations and follow up actions to improve performance • Deliver asset replacement program in line with the budget	

Business Objectives and Targets (by 2025)	**ABS Policy Directives**	**ACS Objectives and KPIs**	**ACS Strategy to deliver ACS objectives**	**Performance Assessment**
	• Unplanned Momentary Average Interruption Frequency Index (MAIFI) contribution target: 0.663	• Complete all scheduled asset inspection and maintenance plans within documented intervals • Review Electricity Primary Plant ACS at least every 3 years	• Deliver asset inspection, condition monitoring, checking & testing programs as per sub-class strategies	
	• Ensure capital program for each Jemena asset is within budget while also delivering planned or equivalent scope of work	• Successfully deliver asset replacement and/or reinforcement (as applicable) program • Deliver asset replacement programs to agreed budget	• Jemena portfolio management • Annual review of projects to be included in COWP • Business case approval process	
Customer Cost per customer trending downward, with no deterioration in service levels	• Incorporate Customer expectations and outcomes into our Asset Investment plans and documents	• Meet all above mentioned safety and performance measures • Engage with customer focus groups • Perform Regulatory Investment Tests for Electricity Primary Plant Investment (RIT-D) • Review equipment and design specification to improve procurement options to reduce asset lifecycle costs	• Attendance at customer forums to obtain feedback • Review and consideration of RIT-D submissions • Review of relevant design, testing and commissioning standards within documented intervals	In addition to the above, ACS objectives and KPIs are supported through establishment of: • Customer Charters • Customer Focus Groups • Regulatory Investment Tests • Customer Relations Team
	• Ensure Customer service levels and customer obligations are met			
Growth Additional growth value created over base business	• Support business development projects	• Procure, build, maintain and dispose of, any new assets required due to growth, in accordance with this ACS.	• Project Management Methodology • Demand forecasting and Customer Initiated Capital (CIC) forecasting methodologies	ACS objectives and KPIs are supported through establishment of: • Timely delivery of customer projects and network augmentations • Meeting budget requirements • Budget reporting • Jemena Portfolio Management Governance

Business Objectives and Targets (by 2025)	**ABS Policy Directives**	**ACS Objectives and KPIs**	**ACS Strategy to deliver ACS objectives**	**Performance Assessment**
People Employee engagement performance	• Improve the linkage of people development activity to succession planning needs and skills gaps in Asset Management	• Identify people development opportunities to address any skill gaps in Asset Management • Promote continual improvement initiatives through training, knowledge sharing and mentoring	• Employee engagement surveys • Employees are encouraged to contribute to development of improvement initiatives (forums, management updates etc.) • Performance Management and Development Plans • Secondments and rotation opportunities • Training and development programs and courses • Succession Planning	• ACS objectives and KPIs are supported through review of: • Employee Engagement Survey Results • Performance reviews occur bi-annually including regular management feedback.