Power Transformers and Station Regulators

AMS - Electricity Distribution Network

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Table of Contents

1 Executive Summary

This document is part of the suite of Asset Management relating to AusNet Services electricity distribution network. The purpose of this document is to outline the inspection, maintenance, replacement and monitoring activities identified for economic lifecycle management of the fleet of zone substation power transformer and regulators.

This strategy applies to the 141 power transformers and 4 off 66kV voltage regulators operating within Zone Substations. AusNet Services also holds three spare transformers that are suitable for direct replacement of 84% of the fleet of transformers.

Maintenance and Replacement investment decisions for power transformers and station regulators are made based on the level of risk posed by the assets. Asset risk considers asset criticality and conditional probability of failure. Risk is mitigated by replacing assets in poor condition, refurbishing major subcomponents, or reconfiguring the network.

Conditional probability of failure takes into account current condition - in which oil, electrical tests and excursions from normal operating conditions are continually assessed – and statistical life. Of the fleet of transformers and regulator, 4% have been assigned a C5 condition and are considered in "Very Poor" condition rapidly approaching end of life. A further 55% are in condition C3 and C4 and considered to be in "Average" to "Poor" condition, which represents normal lifecycle deterioration. Over the last 15 years there have been a steady flow of risk based transformer replacements, now resulting in 27% of the population in condition in C1, with a "Very Low" probability of wear out failures.

Criticality comprises the monetised consequence of safety, unserved energy, environment, and collateral damage. Criticality quantification shows 29% of the fleet of transformer and regulators are in criticality band 3 or 4.

Replacement, maintenance and refurbishment strategies improve the condition of transformers and regulators, thereby reducing the likelihood of failure, thereby reducing risk where failure probability was a driving factor. Presently, 12% of the population of transformers and stations regulators have a risk level, where replacement or refurbishment is warranted during the 2022-26 period.

Proactive management of transformer and regulator inspection, maintenance, refurbishment and replacement practices are required to ensure that stakeholder expectations of cost, safety, reliability and environmental performance are met. The summary of proposed asset strategies is listed below.

1.1 Strategies

1.1.1 New Assets

- Continue to purchase standard power transformer sizes with sealed oil systems, composite /RIP bushings and vacuum tap changers

1.1.2 Condition Inspections

- Continue prioritised electrical insulation tests of transformer bushings and windings with results recorded in SAP.
- Continue annual oil sampling and analysis from main tanks and periodic oil sampling of problematic OLTCs, such as [C.I.C].
- Create transformer measurement points for routine station inspections to add two monthly and monthly condition data to SAP to better prioritise condition based maintenance.

1.1.3 Spares

- Maintain three spare transformers and monitor ongoing holding level requirements
- Maintain HV bushings spares to support testing program

1.1.4 Refurbishments

- Opportunistic condition based replacement of secondary wiring, calibration/replacement of ESP gas relays, and, calibration of winding temperature indicators, and fixing oil leaks.
- Refurbish two transformers prior to 2025

1.1.5 Replacements

- Replace the “Very Poor” condition, high consequence 10% of the fleet of transformers and regulators prior to 2025.

2 Introduction

2.1 Purpose

The purpose of this document is to outline the inspection, maintenance, replacement and monitoring activities identified for economic lifecycle management of the fleet of zone substation power transformer and regulators. The document is intended to communicate the basis for asset management decisions.

In addition, this document forms part of the AusNet Services Management System for compliance with ISO 55000 and relevant regulatory requirements. The document demonstrates responsible asset management practices by outlining economically justifiable outcomes.

2.2 Scope

This strategy includes:

- power transformers within AusNet Services zone substations greater, or equal to, 2MVA
- voltage regulators within AusNet Services zone substation – referred to in this document as 'regulators'.

The strategy excludes:

- pole and pad mounted transformers outside of zone substations
- stand-alone station service transformers within zone substations
- 22kV regulators installed outside of zone substations
- Replacements required for network augmentation - the scope of this document is replacements of transformers based on high risk driven primarily by poor condition.

2.3 Asset Management Objectives

As stated in *AMS 01-01 Asset Management System Overview*, the high-level asset management objectives are:

- Comply with legal and contractual obligations;
- Maintain safety;
- Be future ready;
- Maintain network performance at the lowest sustainable cost; and
- Meet customer needs.

As stated in *AMS 20-01 Electricity Distribution Network Asset Management Strategy*, the electricity distribution network objectives are:

- Improve efficiency of network investments;
- Maintain long-term network reliability;
- Implement REFCL's within prescribed timeframes;
- Reduce risks in highest bushfire risk areas;
- Achieve top quartile operational efficiency; and
- Prepare for changing network usage..

3 Asset Description

3.1 Asset Function

Transformers are required to transfer power between circuits of different operating voltages. Typically zone substation transformers step the 66kV sub transmission network and the 22kV distribution network. The 66kV voltage level is required to transport large amounts of power over long distances with low resistive losses, whereas the 22kV network distributes the power to geographically diverse power consumers.

The power transformer fleet has nameplate ONAN (oil natural air natural)[1] ratings ranging from 2 MVA to maximum continuous power ratings of 45 MVA. In order to maintain rated output voltage, 90% of power transformers are fitted with on-load tap changers (OLTCs), as illustrated in Figure 1.

Figure 1 – Typical Zone Substation Power Transformer with OLTC

Figure 2 - Typical Station Voltage Regulator with OLTC

Resistance in long radial circuits can result in a significant voltage drop. Regulators overcome this by transforming the voltage up so the voltage at end of the line remains within code despite the resulting voltage drop. The installation of a 22kV regulator within a zone substation can increase the voltage of a single feeder without increasing the voltage too much in the zone substation.

Regulators, as shown in Figure 2, are of similar construction and design to a power transformer, thus require a similar lifecycle management.

3.2 Asset Population

The 2017 Category Analysis Regulatory Information Notice (RIN) 5.2 Asset Age Profile reports there are 141 power transformers within AusNet Services zone substations. Additionally, the same RIN reports 144 regulators – 4% are contained within zone substations, or within their own fenced off 66kV yard. The other 96% of the population of regulators are 22kV regulators outside

[1] Refers to the thermal capability of the transformer with an assisted means of cooling – oil pumps and radiator fans.

of zone substations, and are managed according to the line voltage regulator strategy AMS 20-68.

Figure 3 shows 93% of the population of zone substation transformers have a 66kV high voltage winding. The remaining 7% are medium voltage power transformers related to power stations in the La Trobe Valley and supply the 6.6kV distribution network in the Mount Dandenong range.

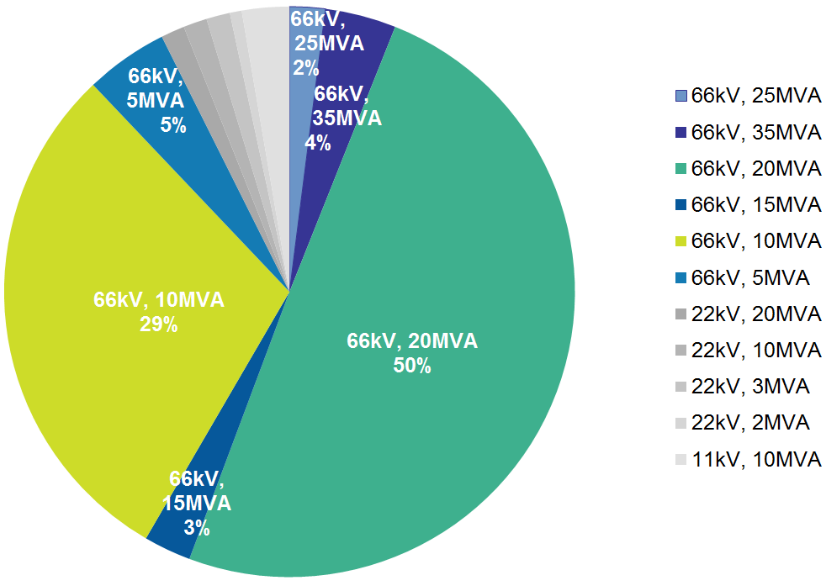

Figure 3 - Power Transformer Population Chart

Figure 4 shows that population of regulators operate at 66kV split between 20MVA and 40MVA. No 22kV regulators remain.

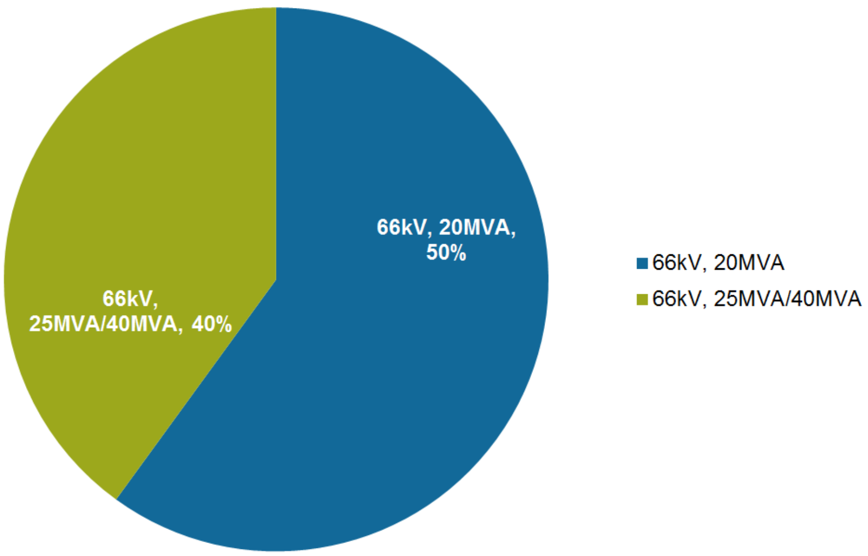

Figure 4 - Station Regulators Population Chart

3.2.1 Manufacturers

Unlike large population fleets, transformers are largely unique in their design and construction. Optimised designs of transformers began in 1960's reaching maturity in the 1980s. Transformers manufactured during this period of maturation transformers were predominantly sourced from local manufacturers – [C.I.C]. This group of transformers constitute 22% of the total population and for which design deficiencies are likely to be common. Otherwise, design issues relate to a specific design rather than a generation of transformer, or a transformer manufacturer.

3.2.2 Vector Group

In addition to having different primary/secondary voltages and manufacturers, the fleet of power transformers also have different 'vector groups'. The ways in which the three-phase windings in a transformer are connected determine which vector group the transformer belongs to. Figure 5 shows the population distribution based on vector group and voltage.

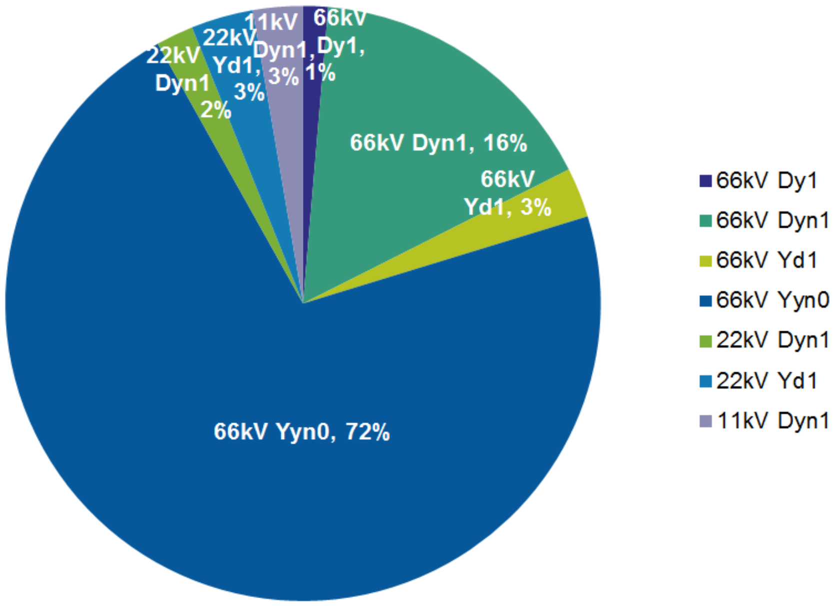

Figure 5 – Percentage of Total Transformer Fleet by Vector Group

The configuration of the primary winding – delta or wye – is the basic differentiating factor between the transformer fleet. Transformers in the northern region of the network have delta primary windings, whereas the remainder of the transformers on the have wye configured primary windings.

Transformers connected in parallel must be of the same vector group due to the difference in tapping capabilities and impedance. Therefore, subsequent to a transformer failure, only a spare transformer of like vector group can be used as a replacement.

3.2.3 Spares

Table 1 lists the three transformers that are in suitable condition to be used as a replacement in the event of a major transformer failure.

Table 1 - Spare Transformers

Location	Region	Voltage (kV)	Phasor	MVA (ONAN)	Year of Manufacturer	Condition	Comments
CYN	Central/ East	66/22	Yyn0(d1)	20	2016	1	
PHM	Central/ East	66/22	Yyn0	10	1965	5	Requires minor refurbishment prior to installation
BWA	North	66/22	Dyn1	15	2018	1	Delivery in progress, delivery expected prior to 2019/20 summer

The three spares are suitable to replace 84% of the fleet of zone substation power transformers in the event of a complete transformer failure. This allows a replacement to be completed in four weeks[2].

The remaining 16% of transformers are incompatible with the spare transformers based on winding configuration or voltage. Of these transformers and regulators that are incompatible:

- 3% are 66kV regulators,
- 4% are related to Morwell and Yallourn power stations – MPS and YPS respectively. By 2021, both stations will have been replaced by stations with transformers that are compatible with the CYN spare.
- 4% relate to 6.6kV power station supplies, which are low criticality from a network perspective
- 3% are 22kV transformer in the Dandenong ranges. This group has a high criticality, however, except UWY, all transformers were replaced in 2013, are in "Very Good" condition and present a low risk overall.

There is a salvaged Ynd1 10MVA transformer at LDL that was listed as a spare. It is no longer suitable as a spare and has been de-listed as a spare, but is recommended that this be disposed as it is unlikely to be used and presents an oil leak environmental risk.

3.3 Asset Age Profile

Figure **6** below shows the age profile of Transformer and Regulators:

[2] This is a high level estimate by the subject matter experts based on repair times of previous failures.

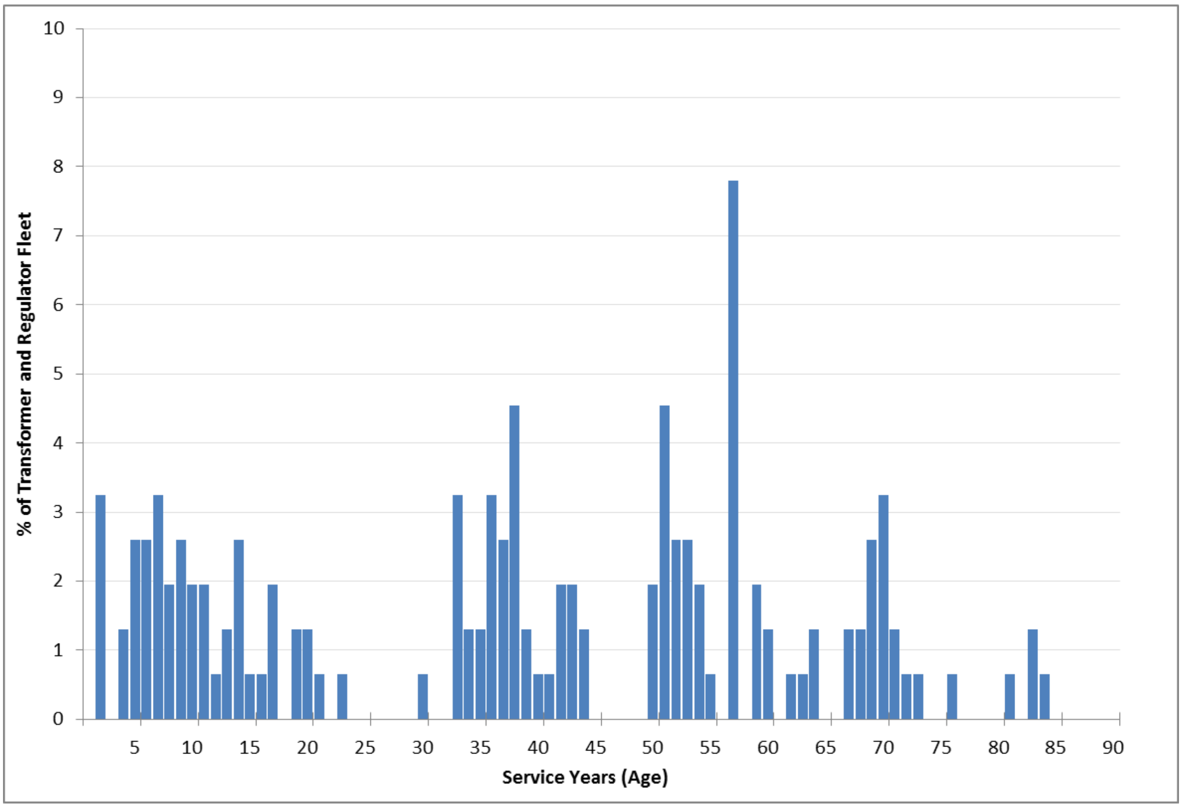

Figure 6 - Transformer and Regulator Age Profile

Figure 8 and Figure 9 in section 3.4 show that depending on operating context and the applied maintenance strategy, increased age does not necessarily correlate with deteriorated condition.

3.4 Asset Condition

Asset condition refers to the conditional probability of failure. When combined with asset criticality an asset risk score can be produced. Asset management decisions are not based on condition alone.

Section 3.4.1 provides a view of the conditional failure probably of the fleet of transformers and regulators. Section 3.4.2 compares the fleet condition profile to the age profile to give an indication of the effectiveness of the transformer and regulator asset management practices.

3.4.1 Fleet Condition

The asset health report document AHR 20-71 details the condition assessment methodology used to give the transformers and regulators an end of life condition score (C1 to C5). The end of life condition score gives an asset a distributed probability of suffering a failure, where the economically feasible means of reinstating the asset function is a wholesale asset replacement. Table 2 summarises the meaning of each of the condition scores for transformers.

Table 2 – Condition Score Definition

Condition Score	Condition Scale	Condition Description	Remaining Service Potential
C1	Very Good	Initial Service Condition	95%
C2	Good	Relatively new, no known issues identified.	70%
C3	Average	Average condition, some minor defects identified. Early signs of deterioration and condition or performance.	45%
C4	Poor	Advancing deterioration – life ending failure highly likely within 10 years without remedial action	25%
C5	Very Poor	Extreme deterioration – life ending failure highly likely within 5 years without remedial action	15%

Figure 7 shows the percentage spread of condition for transformers and regulators.

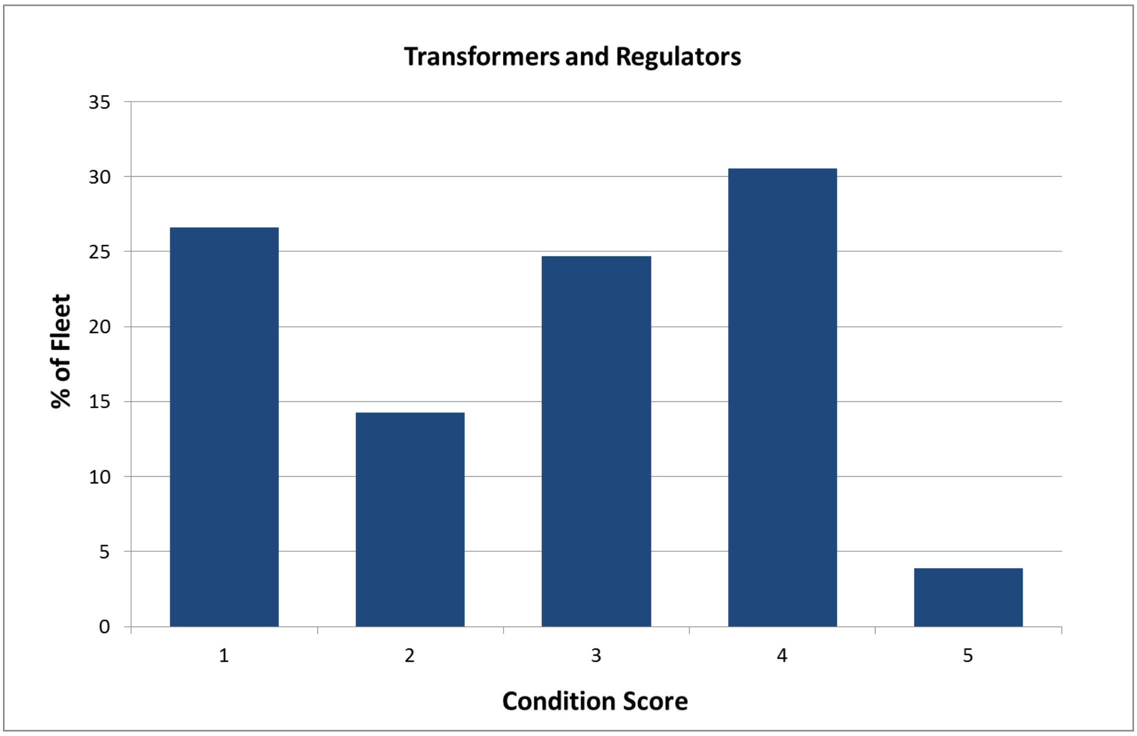

Figure 7 - Transformer and Regulator Condition Chart

Transformers and regulators are plotted as a percentage of their respective fleet eg. 30% of transformers are in condition C4, whilst 50% of the population of regulators are in C4.

3.4.2 Age versus Condition

Comparing the transformer age profile against condition at the start of current regulatory period (2014) and the project end of the current period (2021) provides a means of assessing the effectiveness of the current regulatory CAPEX program. This is illustrated in Figure **8** and Figure **9**:

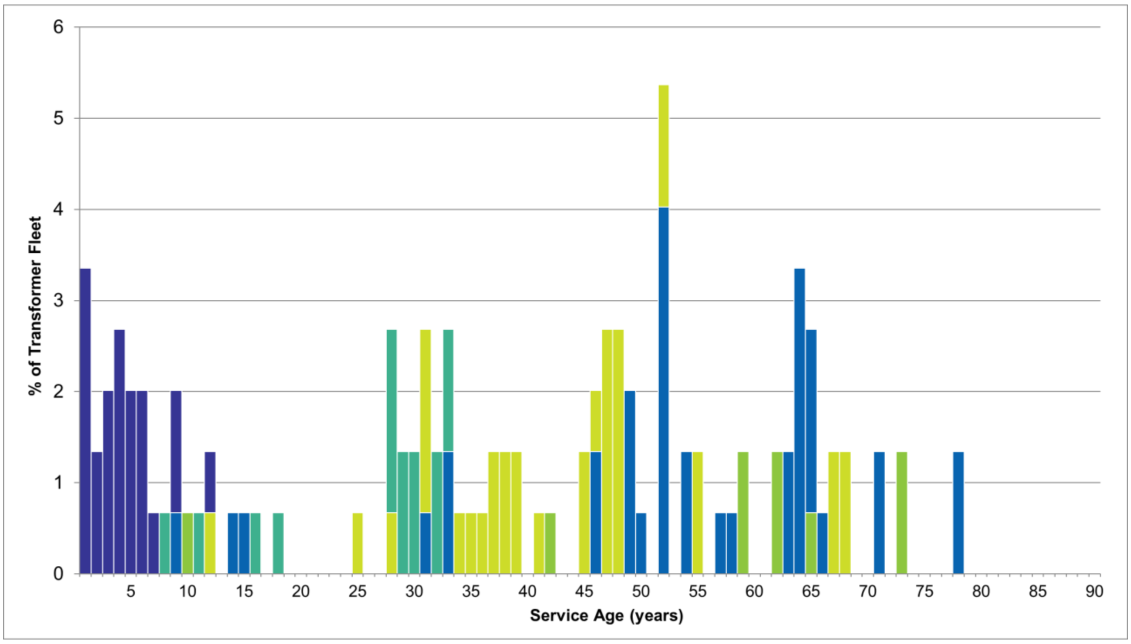

Figure 8 - Condition Overlaid Against Age (2014)

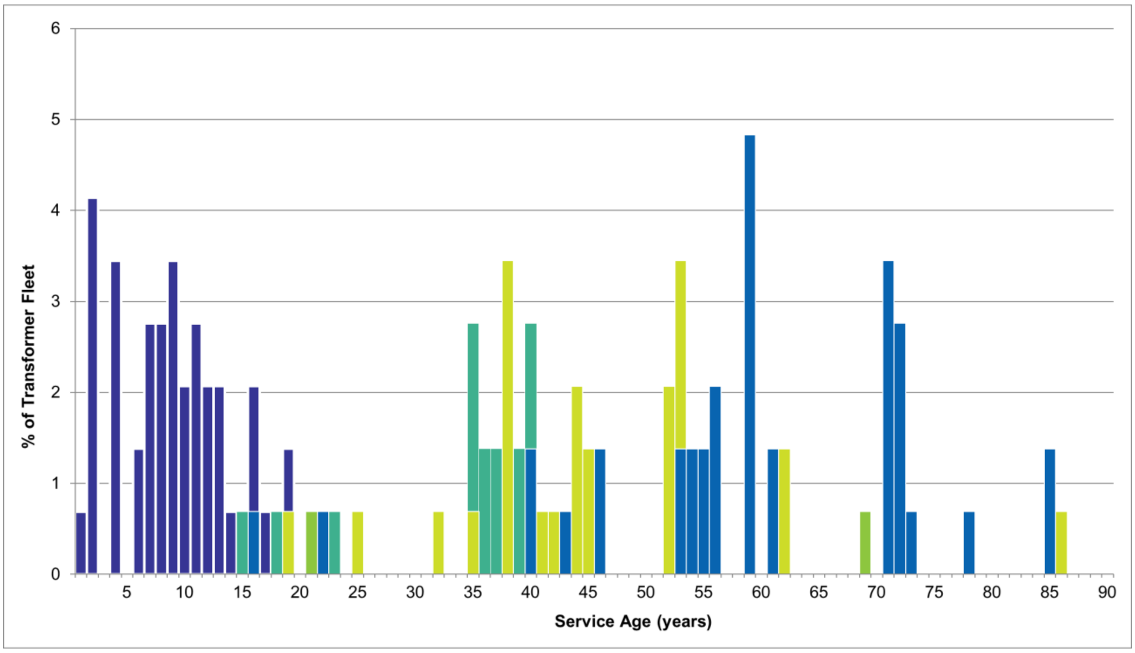

Figure 9 - Condition Overlaid Against Age (2021 projected)

Figure **9** has a much lower proportion of C5 condition assets beyond 50 years. This demonstrates two points:

- The tie between age and condition is diverging - effective maintenance has managed transformers as they the remaining service life is extended.
- Attention can be focused on early detection and treatment of failures. These two charts allow attention to be prioritised on C4 and C5 assets less than 25 years old.

The charts do not show where there are poor condition components. Whilst they may not always result in an unrecoverable failure, they can result in costly failures. Given a better control of end of life failure risk attention can be drawn towards preventing component failures.

Both Figure **8** and Figure **9** contain a C5 rated transformer that was installed in 2000. This is the BWN 1 transformer, which based on oil monitoring, presents an elevated likelihood of failure. This is indicative of a wear-in failure mode.

3.5 Asset Criticality

Asset criticality is a measure of the severity of the consequence of an asset failure. Figure 10 shows the percentage spread of transformer and regulator in a five point ranking:

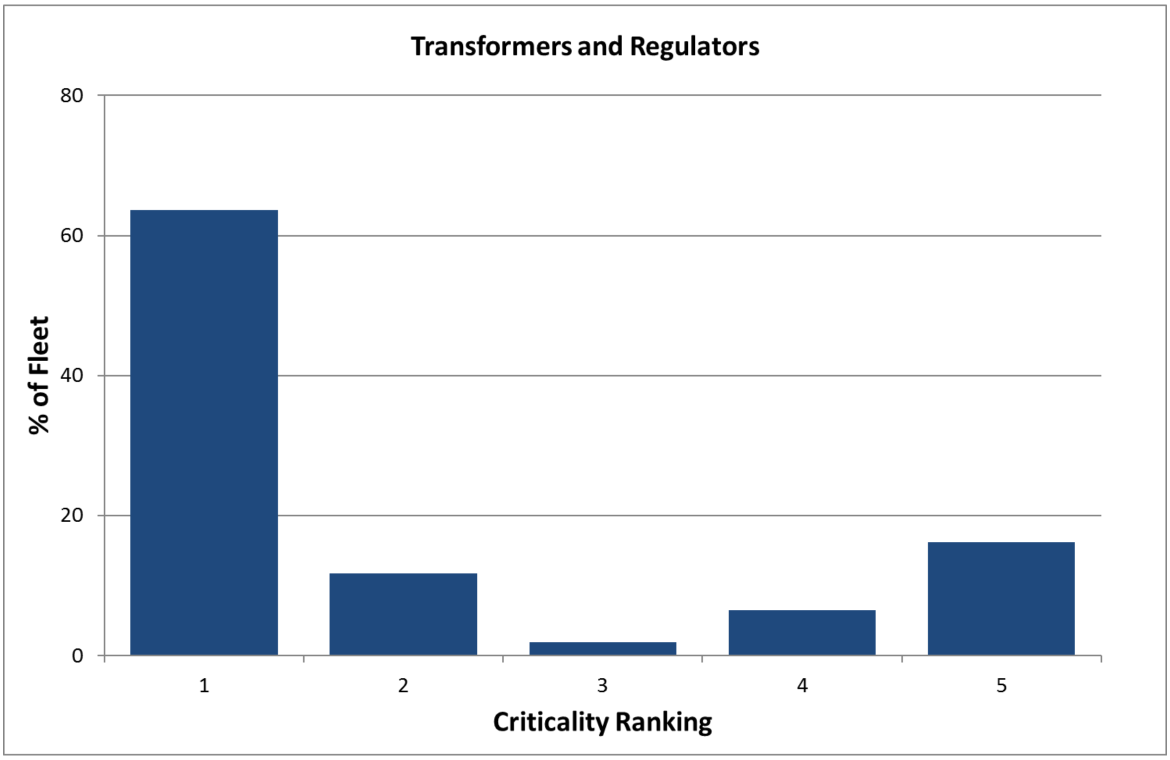

Figure 10 - Transformer and Regulator Asset Criticality Ranking

The five point rank is based on the ratio of monetised failure consequence to the cost of replacing an asset as per Table 3.

Table 3- Criticality Ranking

Criticality Ranking	Economic Impact
1	< 0.3x
2	< 1x
3	< 3x
4	< 10x
5	>10x

The high-level criticality assessment considers the failure of on transformer or regulator in isolation. It is used to identify transformers and regulators that will require detailed risk analysis. Section 0 includes the detailed risk assessment which accounts for effect of compound failures.

Monetised criticality for transformers and regulators is an aggregation of five types of consequences:

- supply
- safety
- bushfire
- collateral damage.

Each of these is described in the following sections.

3.5.1 Supply

Unserved energy is a measure of the impact of customers due to outages caused by the failure of transformers. It relates to transformers alone and is calculated as:

$$VUE = EAR \times VCR \times MTTR$$

Where:

- VUE = Value of Unserved Energy
- EAR = Energy at Risk
- VCR = Value of Customer Reliability
- MTTR = Mean Time to Repair – assumptions stated in Table 4.

Table 4 - Mean time to repair

Spare Transformer	MTTR	MTTR (hours)
Spare available	4 weeks	730
Spare to be procured	9 months	6,575

Works undertaken in previous regulatory periods has reduced number of stations with high demand and banked transformers. As per Figure 11, in 2014 40% of total load was from unswitched stations whereas it is projected that only 13% of total load would be from unswitched stations in 2021.

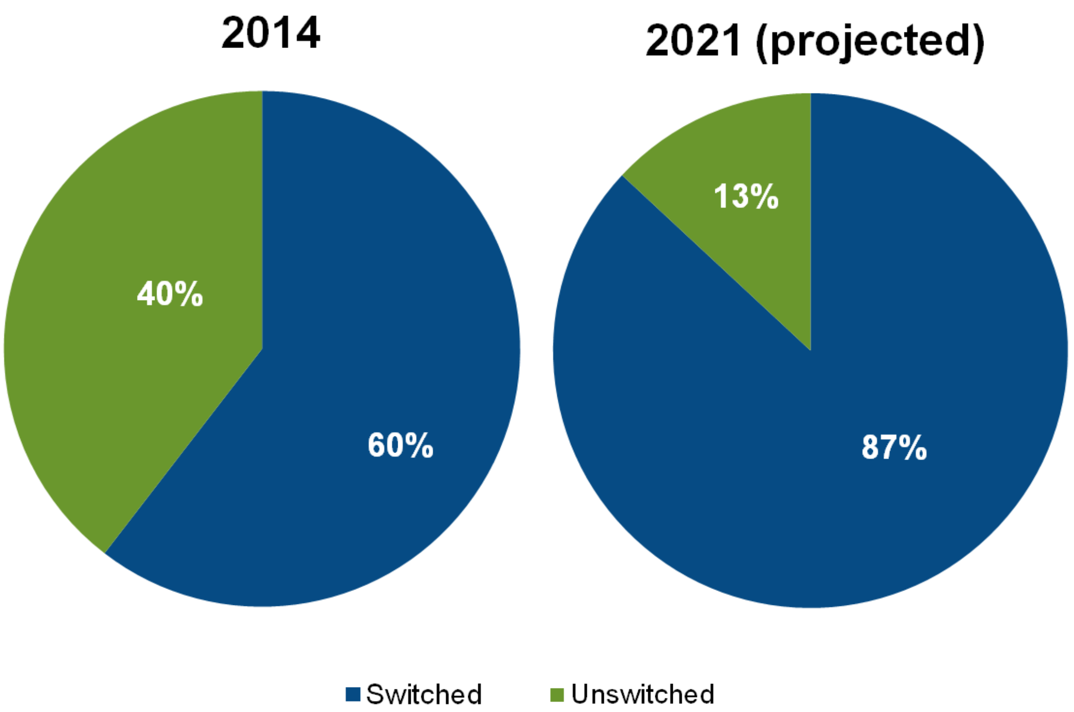

Figure 11 - Switching arrangement by total VUE – 2014 to 2021

3.5.2 Safety

Failure of a porcelain transformer bushing poses a safety hazard to personnel within the vicinity of a transformer, which could result in a fatality. The monetisation of safety represents the cost to the community cause by the serious injury or fatality of an employee or member of the public. In accordance with AusNet Services asset risk assessment guidelines[3] safety effects were monetised using value of statistical life of [C.I.C] and a disproportionality factor of 3.

CIGRE A2.37 2015 lists a 0.1 probability of a bushing failure resulting in an explosion. AusNet Services data shows that 4% of transformer failures are bushing failures. Therefore, for the purposes of high level criticality analysis, the monetised consequence of a transformer bushing failure follows as:

Bushing Safety Consequence = [C.I.C]

This failure consequence applied to all porcelain clad condenser bushings. New transformers are installed with RIP (resin impregnated paper) polymeric bushings, which are consider to fail in a benign manner and have negligible consequences. Polymeric RIP bushings – [C.I.C] - are installed on 12% of the total population of transformers.

[3] AMS 01-09, Asset Risk Assessment Overview, section 4

Section 0 details the methodology for considering the probability of a transformer failure resulting in a fatality, which does accounts for the probability of personnel in the vicinity of at the time of a failure.

Figure **12** shows the distribution of 66kV condenser bushings between resin impregnated paper (RIP), oil impregnated paper (OIP) and synthetic resin bonded paper (SRBP):

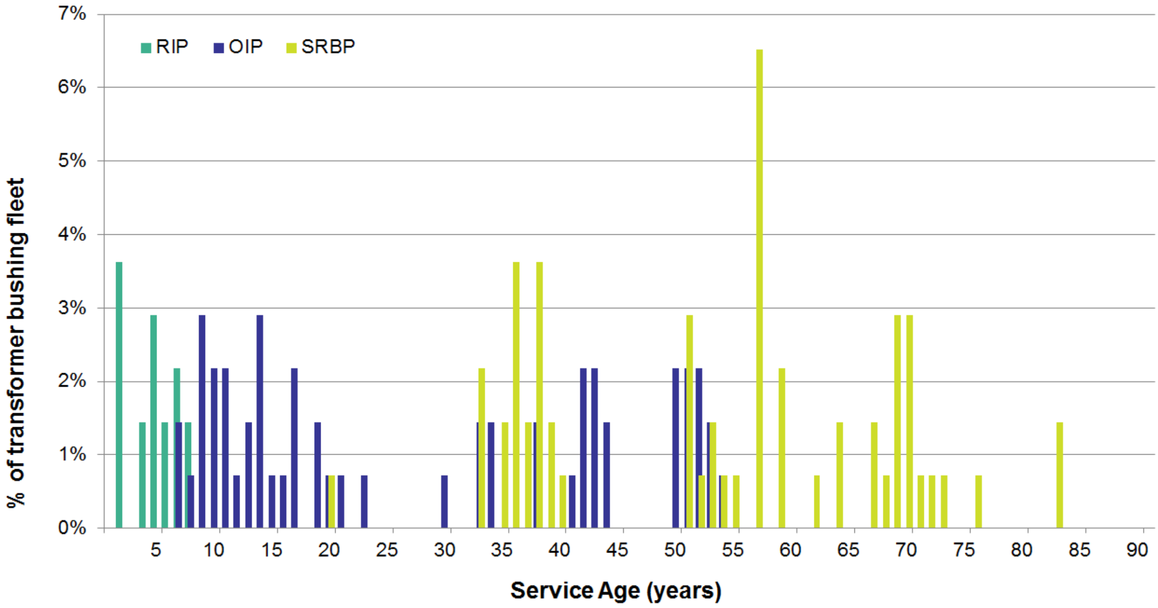

Figure 12 - Age Profile of Transformers (% fleet**)**

RIP have polymeric bushing and result in benign failures. OIP and SRBP are porcelain clad and contain and explosive failure mechanism which has significant safety criticality.

SRBP bushings suffer from delamination and may have a greater likelihood of failure. An understanding of the condition of SRBP bushings, particularly [C.I.C] bushings greater than 50 years old, will allow prioritised replacement.

During REFCL testing however, 40 to 50 year old OIP and SRBP bushings are failing tests at a high rate and should also be considered for condition monitoring. In addition to safety consequences, failure of an OIP bushing is more likely to lead to a complete transformer failure and may actually be a higher risk than SRBP bushings.

Less attention is given to 22kV oil filled bushings than 66kV condenser bushings, as they have a lower failure risk. Because 22kV bushings are not condensed they are designed with a clearance that can be insulated by oil alone. They are proportionally larger than 66kV bushings. Conversely, the grading mechanism in condenser bushings allows for clearances that oil cannot provide insulation for alone.

3.5.3 Environment

The environmental criticality of a transformer failure relates to the adequacy of the bund and oil treatment system. Inadequacy of the bund and oil treatment systems means that if a transformer lost all of its oil, the oil would oil be contained to the station.

In accordance with the continual improvement report – ‘AMS Continual Improvement Report for Terminal Station Assets’ – a baseline figure of [C.I.C] was used to quantify an uncontrolled environmental contamination event.

Analysis of the potential consequences have shown that there is a 10% probability that a transformer failure and subsequent bund system failure would result in an uncontrolled oil discharge.

If oil would be contained for the failure of a single transformer the environmental risks are considered negligible – this is the case for 93.5% of the population of transformer and regulator installations.

3.5.4 Collateral Damage

The mechanism considered for the complete failure of adjacent transformers is an oil pool fire within the bund of the transformer that initially failed. A pool fire requires the leak of a substantial percentage of oil from a transformer, and an ignition. This is only considered possible from an internal flashover which has a spark and a pressure build up that ruptures the main tank wall.

External effect analysis in the CIGRE A2.37 Transformer Reliability Survey Section 6.8 shows 7% of major transformer failures result in fire. Applying this to the relative subsystem failures shows the probability that a transformer failure will result in fire to adjacent transformers as shown in Table 5.

Table 5 - Probability of Oil Pool Fire

Subsystem	Probability Failure Results in Fire (%)	Relative Occurrence of Failures (%)	Probability of failure resulting in a Pool Fire (%)
OLTC	7	13.5	0.95
Core & Winding	7	9.5	0.67
Bushing	7	30.2	0.89

Where transformers are physically separated, contained within a sound enclosure, or has a fire wall or blast wall, collateral damage criticality does not apply. Figure 13 shows 70% of the total population of stations transformers and regulators have sufficient fire separation.

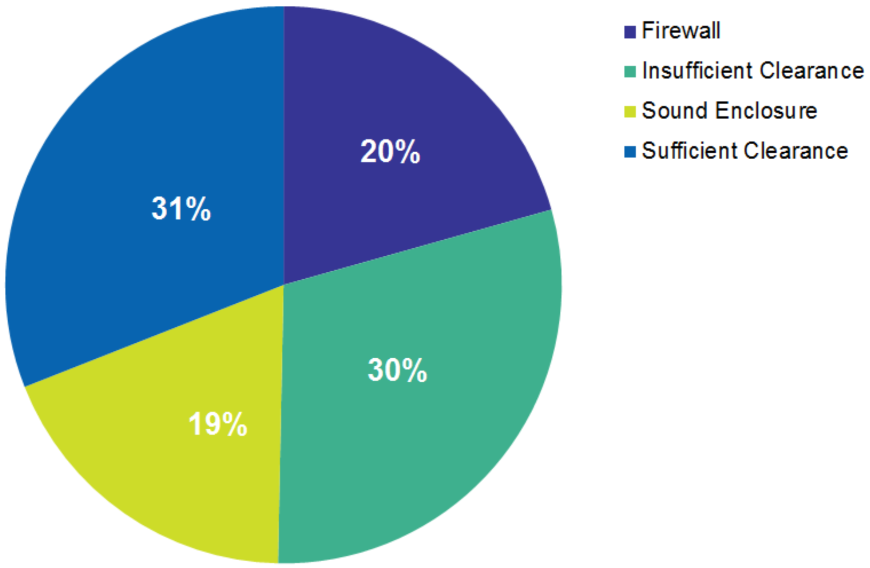

Figure 13 - Transformer and Regulator Fire Separation

3.6 Asset Performance

3.6.1 Major Failures

Table 6 shows the list of major failures of zone substation transformers and regulators. Major failures require the wholesale replacement or replacement of a major sub-component, both of which require extended outages.

Table 6 - Major Failures of zone substation transformers and regulators

ZSS	Desc.	Date	Problem/Root Cause & Remarks	Action Taken	Time to return to Service (Days)
RWN	No 2 & No 3	1970s/ 80s	C.I.C	Repaired on site	Data not available
MDI	No 1	Early 1990s		Transformer Replaced	
RWN	No 2	1980s		Redesigned and repaired	
TGN	No 3	1994		Repaired at site	
FGY	No 1	2002		Repaired at site	
LGA	No 1	2002		Repaired at site	
HPK	No 1	2003		Replaced complete OLTC with a new one	
WGL	No 3	2003		Repaired at site	
BWR	No 1	2004		Replaced with bolted link	
LGA	No 3	2005		Transformer removed from site for repair	
CYN	No 2	2005		Repaired OLTC at site	

ZSS	Desc.	Date	Problem/Root Cause & Remarks	Action Taken	Time to return to Service (Days)
RWN	No 2	2007		Replaced with bolted link	
LLG	No 1	2008		Replaced bushings	
SMR	No 1 & No 2	2008		Replaced lid gasket on site	
SLE	No 1	2009		Repaired and tested at site	
RWN	No 3	2014	C.I.C	Transformer being replaced. Resulted in expensive remedial work and site clean-up as a result of oil spill	19
DRN	No 2	2017		Repair HV Bushing lead inside tank	63
BWR	No 2	2017		Repair connection	6
WGI	No 3	2018		Replace 66kV Bushings	15

Of the 21 major failures and defects listed, 10 were failures of OLTCs or off-circuit switches.

3.6.2 Minor Failures

In addition to major failures and defects, Table 7 shows minor failures gathered form SAP notifications and Maximo 6 work orders between 2008 and 2018. Minor failures can be repaired on site without extended outages.

Table 7 - SAP and Maximo 6 minor failures

	Priority > 7 days		Priority ≤ 7 days	
Bushing	35	13%	1	4%
OLTC	126	48%	18	72%
C&W	101	39%	6	24%

The failure data is delineated between those given a priority of 7 days or less, those given a priority of greater than 7 days. This gives an indication of severity of the failure, the higher the days assigned to a failure the more likely it is benign or was required to addresses small deterioration in condition.

Again it shows that OLTCs have, historically, been the most problematic subsystem of zone substation transformers and regulators. One major contributor has been the fleet of [C.I.C] OLTCs, which have had failures resulting from contacts that have deteriorated faster than time-based maintenance intervals were able to detect. More frequent condition inspections using dissolved gas analysis (DGA) have provided early warning, and allowed maintenance to prevent failures. As the selector switch is integrated within the transformer main tank, OLTC replacement is not feasible - eventually the condition of [C.I.C] tap changers will lead to the replacement of the transformer.

The strategy to install all new transformers with vacuum contactors is expected to lower the relative occurrence of OLTC failures. For OLTCs remaining, oil sampling and electrical testing can reduce the relative occurrence of OLTC failures. Employing both strategies can lead to a relative occurrence of that better represents the CIGRE average.

3.6.3 Failure by Subsystem

AusNet Services historical failures show the majority of transformer failures result from a failure of the OLTC, with a 72% relative rate of occurrence. Core and winding failures lead to 24% of the failures and bushings lead to 4% of transformer failures.

Figure 14 shows a comparison of relative occurrences of failures between Bushings, OLTC and Core and Winding (C&W) collected from AusNet Services historical data and the CIGRE transformer reliability survey (A2.37 642 2005).

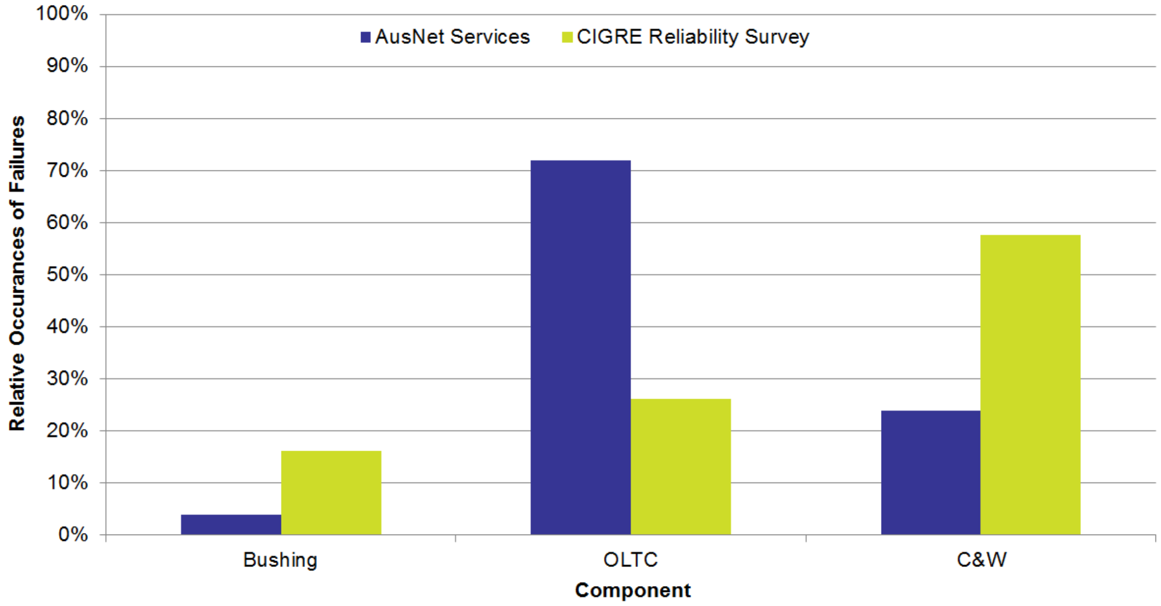

Figure 14 - Relative Occurrences of Failures per Subsystem

4 Other Issues

4.1 Core, Winding and Bushings

Three noteworthy issues with core and windings, and bushings relate to HV testing, corrosive sulphur and short circuit withstand capability:

4.1.1 High Voltage (HV) Testing

High voltage winding electrical tests and bushing tests have been completed on zone substations on an ad hoc basis since 2010. Testing has been undertaken on 22% of the population of zone substation transformers and regulators in that time with about 1 in 3 of the older 66 kV SRBP bushings requiring replacement. This means valuable condition information is missing on 78% of the population, and as a result, the risk of an unplanned outage due to an interval flashover or bushing failure is potentially high and is not as well understood. Off-line condition based tests, together with DGA and oil tests would provide improved understanding of the condition of each transformer for a more focused condition based maintenance/replacement programs to be employed.

Figure 15 shows the HV tests undertaken against the age profile. Trending of paper deterioration and grading delamination should commence much earlier to allow replenishment works to be better planned and more effective.

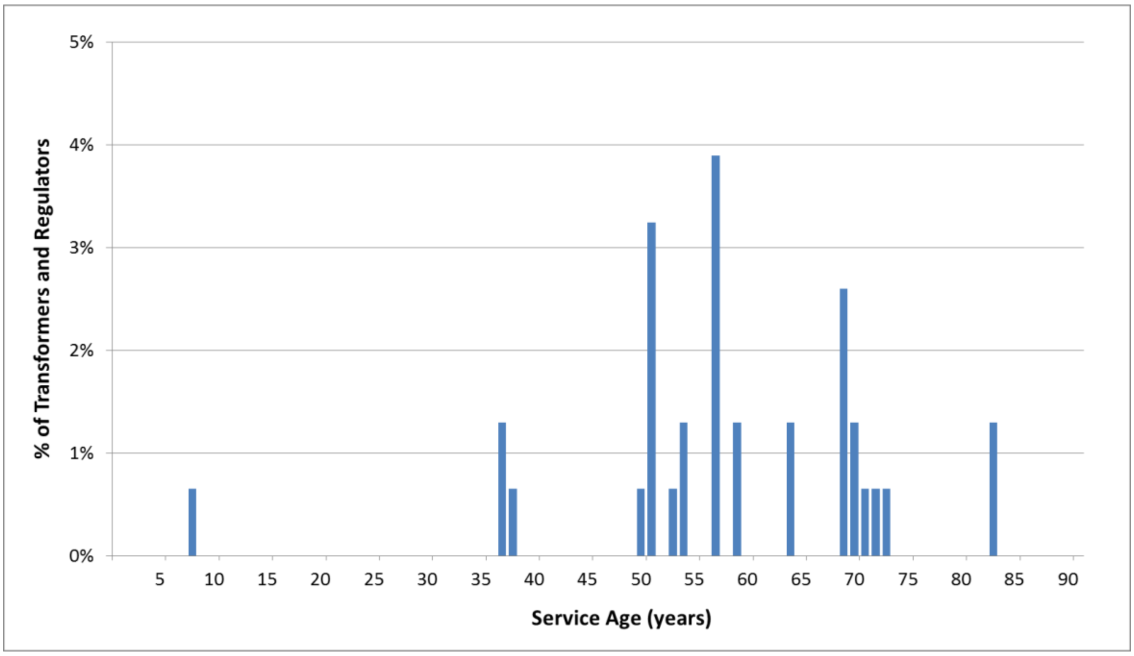

Figure 15 - HV Tests

As per section 3.5.2, the population of SRBP bushings from the 1940s and 50s are expected to present the highest risk.

4.1.2 Corrosive Sulphur

Corrosive sulphur is a risk for a group of transformer 1999 to 2007. Although oil passivator helps to prevent copper corrosion, there is mounting industry evidence that silver plated selector contacts are beginning to fail[4]. This is a driver for undertaking OLTC inspections and tests.

4.1.3 Short Circuit Withstand Capacity

[C.I.C] transformers manufactured between the 1960s to 1972 have 50 % short circuit capability. This may lead to early retirement of transformers due incapability and an elevated risk of failure as load and fault levels increase.

The through fault failure at Doreen Zone Substation in 2017 was a result of poor site assembly with the HV winding exit leads not secured correctly for through faults. 3% of the total population are of the same design, 2 transformers at DRN and WT had HV winding exit leads secured, 4 transformers at KLK x 2, LDL, LYD remain to be corrected.

4.2 OLTCs and Off-circuit Switches

4.2.1 OLTCs

Replacement of OLTCs that are about to fail may save the complete replacement of a transformer. However, as Figure 16 indicates, OLTCs are only technically replaceable on 70% of the population of transformers and regulators. The OLTC is so intrinsically embedded in the main tank for the remaining 30% of the population that OLTC issues a become life limiting issues of the transformer or regulator.

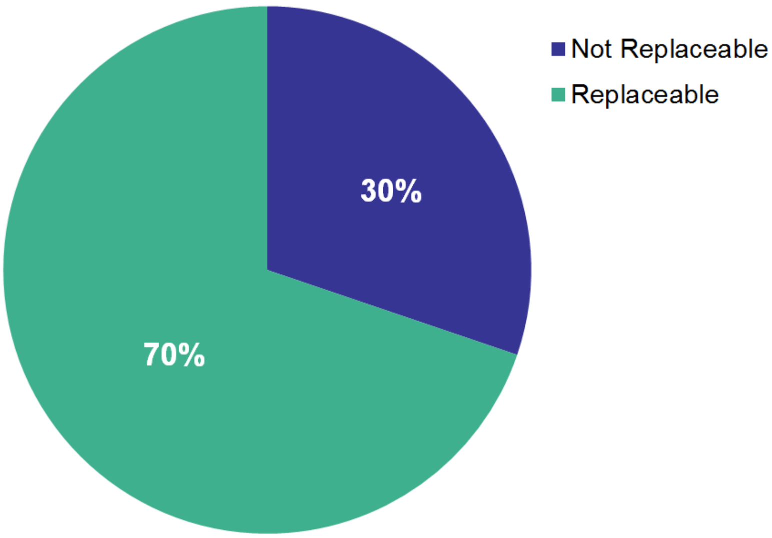

Figure 16 - Technically Replaceable OLTCs

Two issues relating to OLTCS are:

1. [C.I.C] OLTCs have an elevated risk of failure to do short service life.

[4] CIGRE, WG A2.40, technical brochure 625, 2015

2. [C.I.C] OLTCs have reverse power flow limitations, which is a consideration for network planning as distributed generation increases.

4.2.2 Off Circuit Tap Switches

Between the 1950s and the 1980s all transformers within the greater Melbourne metropolitan region were installed with a tap on the 22kV winding to achieve network planning flexibility. The LV Winding Off-Circuit Tap switches over time have an elevated likelihood of failure resulting from high resistance contacts due to spring aging and lowering contact pressure. As the switches have never been required, bridging out the switches is a means of removing this risk.

4.3 Main Tank

Significant oil leaks have become an issue that results in expensive repair work. One cause of oil leaks is the weather related reduction of surface preserving paint systems. Repainting is a means of halting transformer deterioration – however this becomes costly when the original paintwork contains lead based paint.

4.4 Protection, Control and Auxiliary Components

Deterioration and malfunction of protection, control and auxiliary components, whilst minor in themselves, may lead to costly failures. The major risk factors are:

1. Many winding temperature indicators (WTIs) are either uncalibrated, or of unknown operability. Uncalibrated or inoperable WTIs cannot be relied on to provide controlled operation of transformers.

2. ESP type gas relays have not calibrated. They need to be calibrated under an intrusive outage or replaced. The non-operation of a gas relay may lead to larger consequences than a failure with a correctly operating relay. In addition to the unknown availably of ESP relays, they add confusion for routine maintenance - pressure test are undertaken for ESP relays in free breathing transformers, but this is not appropriate for sealed transformers, and could lead to maintenance induced failures.

3. Secondary wiring aging and oil leak induced deterioration of the conductor polymer insulation may lead to the maloperation of an auxiliary or control circuit. Wiring should have condition assessed and restorative work undertaken on an opportunistic basis.

5 Risk and Options Analysis

Poor condition of transformers and regulators from section and 3.4 were compared against their criticality in section 3.5. From this 19% of the population of transformer and regulators that are critical regulators where condition improvement or replacement may have a positive impact on the risk.

Detailed options analysis was undertaken in Availability Workbench (AWB) on this 19% of the fleet. The detailed AWB models where created to identify a base-line "do nothing" risk cost value, then model the risk reduction of various actions including:

- Transformer replacement
- Component replacement (OLTC, bushings, etc.)
- Life extending refurbishment works (tank refurbishment, oil refurbishment, etc)

The viability of each of these options was then tested by comparing the life extension achieved by undertaking the task against the cost of undertaking the task. A task was considered unviable if the benefit to cost ratio could not be achieved within the period of time that the life of the transformer was extended by.

5.1 Risk Inputs

5.1.1 Failure Modes

Fault tree analysis (FTA) determined there are six dominant failure modes that will result in transformer end of life. Table 8 summarises the six failure modes and their relative occurrence rates in line with section 3.6.3. Failure mode weighting are produced by diving the subsystem relative occurrence rates by the number of critical failure modes for each subsystem.

Table 8 - Failure Modes and Relative Occurrence

Subsystem	Failure Mode Description	Relative Occurrence	Failure Mode Weighting
C&W	Internal short circuit due to contaminated oil	0.24	0.12
C&W	Internal short circuit due degraded cellulose	0.24	0.12
OLTC	Internal flashover due to breakdown of the oil insulation	0.72	0.24
OLTC	Internal flashover caused by in inter-turn tap fault	0.72	0.24
OLTC	Internal flashover causes by high resistance tap contact	0.72	0.24
Bushing	Internal bushing short circuit due to graded insulation deterioration	0.04	0.04

5.1.2 Task Effectiveness

Assisted by the FTA exercise from section 5.1.1, task effectiveness was assigned to seven restorative tasks. Table 9 shows the results.

Table 9 - Task Effectiveness

Task	Effectiveness of a Task per Failure Mode (%)					
	OLTC 1	OLTC 2	OLTC 3	C&W 1	C&W 2	Bushing
Replace OLTC	90	90	90	0	0	0
Replace HV Bushings	0	0	0	0	0	82
Repair Oil Leaks	50	25	0	50	24	0
Process Oil	17	17	0	50	24	0
Repair Oil Leaks and Process Oil	75	38	0	75	36	0
HV Test	0	0	0	0	0	0
Replace Transformer	100	100	100	100	100	100

The task to replace OLTCs in service is only technically feasible for bolt on diverter and selector switches. Figure **16** shows that 30% of OLTC are not replaceable and the only option is to maintain the OLTC until it is economically feasible to replace the entire transformer or regulator. In this situation the OLTC really becomes the life limiting subcomponent.

Replacing a OLTCs and bushings are only 90% and 82% effective respectively, as these tasks have inherent risks, including compatibility, contamination, and quality of onsite installation.

5.1.3 Task Costs

The cost estimates used in the model to determine the viability of restorative tasks are shown in Table 10.

Table 10 – Direct Cost Estimates

Task	
Replace transformer (5MVA)	
Replace Transformer (10MVA)	
Replace Transformer (20MVA)	C.I.C
Refurbish tank	
Replace bushing	
Refurbish winding insulation	
Replace Bolt On OLTC	

Note:

- Refurbish winding insulation includes oil process, dry out and re-clamping.
- Tank refurbishment includes refurbishment of all active oil containing components.

5.2 Model Outputs

Where a replacement was feasible, no further options were considered. If not, lower cost lower benefit options were explored – such as OLTC replacement or oil system refurbishment.

Figure 17 shows that 4% of the population are being replaced or refurbihsed prior to 2021 under committed projects. Of the remaining 15% transformers and regulators considered to be high risk at a high level, the models showed that:

- replacements are feasible for 11% between 2021 and 2030
- none of the 'subcomponent' tasks listed in Table **9** were economically feasible over the 2021 – 2030 period for the remaing 4% of transformers and regulators in the high risk category.

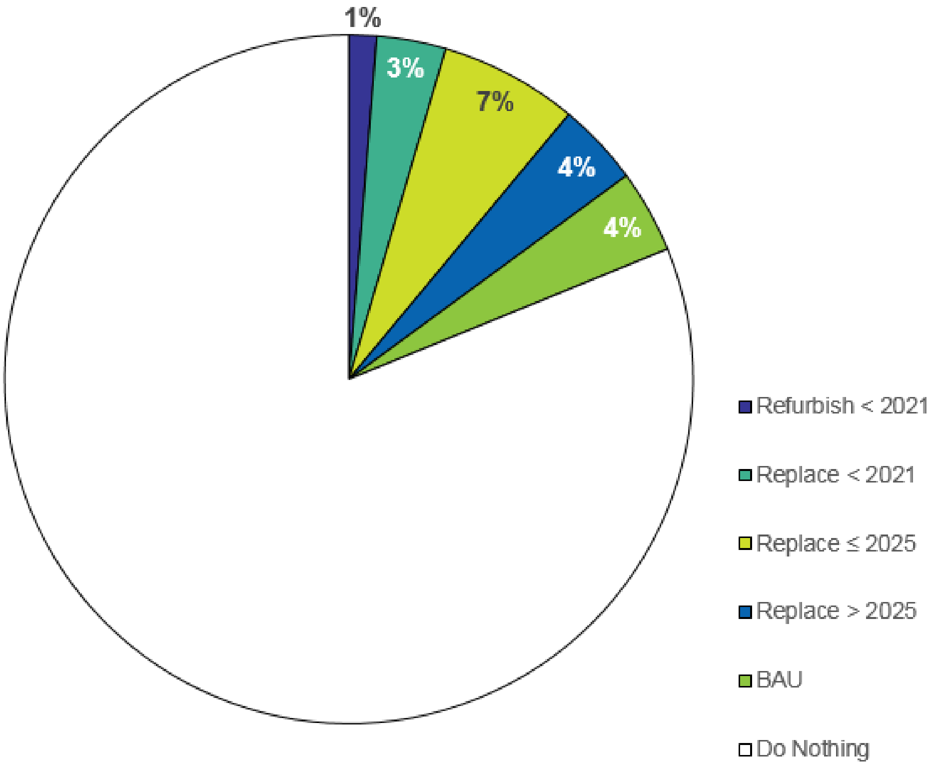

Figure 17 - CAPEX Replacement and Refurbishment

The remaining 81% of the fleet of transformers and regulators are low to moderate risk level. They shall be managed with routine maintenance strategies.

5.3 Forecast Replacement Program

In line with Figure 17, the CAPEX strategy considered to 2030 includes the following replacement and refurbishment projects:

- Replace:
  - One 22kV 5MVA transformer prior to 2025
  - Four 66kV 5MVA transformers prior to 2025[5]

[5] Two 66kV 5MVA transformer replacements have projects committed for completion prior to 2021.

- Two 66kV 5MVA prior to 2030
- Ten 66kV 10MVA transformers prior to 2025[6]
- Four 66kV 10MVA transformers prior to 2030

- Refurbish:
  - Two 66kV 10MVA transformers prior to 2025[7]

Five transformer replacements and two transformer refurbishments are part of committed projects, which are due for completion prior to 2021. Of the remaining works, six transformers are proposed to be included in station rebuild projects.

5.4 OPEX Program

The OPEX strategy helps prioritise maintenance activities within zone substations based on risk posed by transformer and regulators. The strategy focuses on restorative activities that reduce failure risk by returning conditional failure probability back in line with the characteristic life of the transformer or regulator. The strategy returns expected life rather than extending it.

The strategy consists of time-based inspections with follow-on condition based maintenance, refurbishment, component replacements and complete transformer replacements to follow. Follow-on maintenance activities reduce risk by reducing the condition probability of failure, or reducing the safety consequences inherent to a component.

In addition to business as usual maintenance the major items of focus for the transformer and regulator OPEX strategy are:

1) Scheduled electrical tests of transformer bushings, prioritising SEC branded SRBP bushings and early generation OIP. Measurement points are to be created in SAP in order to capture leading indicators of condition.
2) Scheduled HV testing of windings with tests carried out every 8 years. Tests shall be limited to all transformers greater than 30 years old as there is little value in measuring deterioration in early life. Measurement points are to be created in SAP in order to capture leading indicators of condition.
3) Scheduled oil sampling of OLTCs. Prioritising [C.I.C] OLTC oil sampling every 6 months. Measurement points are to be created in SAP in order to capture leading indicators of condition.
4) Condition of transformer sub-components to be assessed during transformer electrical tests
5) Opportunistic condition based
   - replacement of secondary wiring
   - calibration/replacement of ESP gas relays
   - calibration of winding temperature indicators.
6) Create transformer measurement points for routine station inspections to add two monthly and monthly condition data to SAP to better prioritise condition based maintenance. Particular emphasis is to be paid to bushing oil levels, oil leads and WTI readings.
7) Maintain three spare transformers.

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[6] Three 66kV 10MVA transformer replacements have projects committed for completion prior to 2021.
[7] Both transformer works replacements have projects committed for completion prior to 2021.

6 Strategies

6.1 New Assets

- Continue to purchase standard power transformer sizes with sealed oil systems, composite /RIP bushings and vacuum tap changers

6.2 Condition Inspections

- Continue prioritised electrical insulation tests of transformer bushings and windings with results recorded in SAP.
- Continue annual oil sampling and analysis from main tanks and periodic oil sampling of problematic OLTCs, such as [C.I.C].
- Create transformer measurement points for routine station inspections to add two monthly and monthly condition data to SAP to better prioritise condition based maintenance

6.3 Spares

- Maintain three spare transformers and monitor ongoing holding level requirements
- Maintain HV bushings spares to support testing program

6.4 Refurbishments

- Opportunistic condition based replacement of secondary wiring, calibration/replacement of ESP gas relays, and, calibration of winding temperature indicators, and fixing oil leaks.
- Refurbish two transformers prior to 2025

6.5 Replacements

- Replace the “Very Poor” condition, high consequence 10% of the fleet of transformers and regulators prior to 2025