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REVIEW OF ASSETS FOR REPLACEMENT OF SUBSTATIONS WITHIN JEMENA'S NETWORK

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ABBREVIATIONS

Term	Description
HV	High Voltage
LV	Low Voltage
CB	Circuit Breaker
CT	Current Transformer
VT	Voltage Transformer
Tx	Transformer
SA	Surge Arrester (also Lightning Arrester)
DDF	Dielectric Dissipation Factor
PD	Partial Discharge
DGA	Dissolved Gas Analysis
TDCG	Total Dissolved Combustible Gas
DLA	Dielectric Loss Angle
ºC	Degree Celsius
ONAN	Oil Natural Air Natural
ONAF	Oil Natural Air Forced
ODAF	Oil Directed Air Forced
kV	Kilovolts
MVA	Mega-Volt-Amperes
MW	Mega -Watts
VAr	Volt-Amperes Reactive Power
AVR	Automatic Voltage Regulation
Ez%	Impedance %
AER	Australian Energy Regulator
ZSS	Zone Substation
CN	Coburg North (CN)
CS	Coburg South (CS)
NH	North Heidelberg (NH)
PV	Photovoltaic
PoF	Probability of Failure
PCB	Polychlorobiphenyls
UV	Ultra – Voilet light

1. INTRODUCTION

This document provides Jenema a review of the condition-based data associated with the possible replacement of assets within the Coburg North (CN), Coburg South (CS) and North Heidelberg (NH) zone substations for their AER submission. The scope of the work under the engagement of K-BIK Power by Jemena includes:

- Develop a FMEA which includes as risk assessment on:
  - the transformers, switchyard primary plant and switchboards at Coburg North
  - The 66kV circuit breakers and 22kV switchboards at Coburg South and North Heidelberg substations.
- A Weibull style Probability of Failure (PoF) for the transformers and switchboards.
- An outline of an options analysis for the replacement, refurbishment, or relocation to lower the loads or derate of the assets as applicable.

The report is based on asset data provided by Jemena and includes:

- Transformer DGA results
- Operational data for the substations including historical and projected loads
- Maintenance data on all equipment
- Condition assessment data on all equipment.

A part of this assessment K-BIK Power undertook a short literature review of the Jemena AER submission and external engineering papers on asset failure probabilities. The external literature review included an IEEE paper D. Martin, J. Marks, T. K. Saha, O. Krause, and N. Mahmoudi, "Investigation into Modelling Australian Power Transformer Failure and Retirement Statistics" which was published in the IEEE Transactions on Power Delivery, VOL. 33, NO. 4, AUGUST 2018.

In this publication the authors had provided a comprehensive assessment of the failure and retirement statistics for transformers within Australia. Their assessment used the British Standards publication BS EN 61649:2008 Weibull analysis to review the failure statistics and derive the probability of failure of transformers within Australia. It was noted that almost all power utilities within Australia had provided data via a survey and therefore the analysis was founded in local factual data.

The assessments were made based on the probability of failure at any point in the life of the transformer and the data provided where a transformer reached an effective end of life and was retired before it failed. K-BIK Power has used the outcomes of this paper to provide Jemena with a Weibull curve for transformers $\leq$66kV and identified where the Coburg North Transformers lie on those curves.

In addition to this information obtained from CIGRE and FM Global with respect to transformer failures based on the condition, have provided sufficient detail from international statistics to support the Weibull analysis and provide a high level of confidence with respect to the PoF of these transformers.

The report reviews the above and the FMEA and risk assessments to discuss the condition and risks associated with each asset class at each individual site. This is detailed in subsections within each site section below.

At the conclusion of each site section the whole of site condition, risk and probability of failure are discussed and conclusions made.

2. COBURG NORTH ZONE SUBSTATION

The Coburg North ZSS was commissioned circa 1966 and therefore the assets (based on nameplate age) are 59years old. This section looks at the risks associated with this site, options for refurbishment, replacement (like-for-like) or complete rebuild of the site. The individual key asset conditions and options are discussed and recommendations made based on this information and the FMEA provided separately to this report.

The CN ZSS is located as below in the screenshot from Google maps.

As can be seen from the google maps image CN is an open switchgear type substation. The southern side shows the 3 power transformers and the incoming 66kV feeders with 66kV circuit breakers and isolators. On the northern side of the substation is the 22kV switchyard. The 22kV circuit breakers are indoor breakers housed in outdoor enclosures and connected to the 22kV busbars.

This type or design of substation is no longer built as it presents significant safety risks to maintenance and operational staff. The 22kV switchgear is also exposed to the elements and creates a reliability issue as it ages and subjected to intense storm activity.

It should be noted that whilst it is functional the safety risks associated with performing maintenance or replacing any single component of primary plant within the 22kV yard requires complex switching arrangements and a high degree of work protection from adjacent live equipment.

Replacement of any single primary plant item within the 22kV yard may require a crane for lifting the asset. As can be seen there is almost no space to access any component closely and so an extended boom crane would be needed, and a larger section of the substation would be required to be offline whilst the asset is removed and replaced. This means that the substation availability at that time would be very limited, and loads would need to be transferred to other substations for extended periods.

If a 22kV circuit breaker/switchboard, disconnector or instrument transformer failed catastrophically then it is also likely that surrounding assets could be damaged by shrapnel for the explosive failure. This would then create a situation where a larger portion of the substation is offline for an extended period whilst repairs are undertaken.

The area around CN ZSS is largely industrial and the need for a reliable supply is paramount to the business community and Jemena customers. There are numerous industrial buildings in the area with large rooftop PV systems (observed via Google Maps) and this sets up a situation with reverse power flows throughout the day. Jemena have advised that this ZSS supplies some 24,000 customers and therefore, is a key part of their network and reliability for the type of customers is important.

As the CN ZSS equipment was manufactured in circa 1971 it was not designed to managed reverse power flows nor inverter switching transients and harmonics associated with power electronics. There have been many recent studies done on the impact of power electronics on aged assets along with the impact of the voltage stability issues. These create additional electrical stresses on the already aged primary plant. More specifically voltage rises due to high PV penetration will stress the equipment as it would be operating at higher-than-normal design levels and so the internal insulation is subjected to that additional electric stress.

This Section of the report provides more detail around the condition of the assets and their risk of failure. It looks at the age and general condition of the assets and its ability to perform reliably into the future if required.

2.1. ZSS Power Transformers

2.1.1. General Condition

Based on the data provided by Jemena, it has been assessed that the two AEI transformers are in poor condition. This is based on the DGA and furan results.

Transformers No.1 and No. 2 both have aged tapchangers made by AEI and are no longer made. Parts are not available unless obtained from other scrapped OLTCs or re-engineered. The OLTC on each is a single resistor type which have excessive contact arcing wear under reverse power flows from renewable energy sources such as rooftop PV. The Coburg area has substantial rooftop PV and this creates the reverse power flows. To overcome the excessive wear Jemena would need to restrict the operation of the OLTC during reverse flow times which in turn will cause voltage issues on the network.

As the PV and any other renewable (eg battery support) energy supplies are connected to the grid near the ZSS it will have a profound impact on these older transformers and their ability to provide reliable and quality power to the network.

It should be noted that the 3rd transformer has an OLTC that does not have the same issues as it is a two-resistor type tapchanger that is unaffected by reverse power flows.

The DGA and oil quality were reviewed, and it was noted that both these transformers have deteriorating interfacial Tension results (IFT). The oil requires the IFT to be >22 dynes and Transformer No. 1 is at an average value of 16.7mN/m and Transformer No. 2 at an average of 18.6 mN/m. This means that the quality of the oil in each unit is deteriorating by oxidation and as the IFT reaches <15 mN/m it would be considered as placing the transformer at high risk of failure due to dielectric fluid breakdown. The only option for slowing this process is to replace the oil in each transformer. It will not stop the process as it has already affected the paper insulation, and the furans analysis shows each unit has very little life remaining. Based on the trending of the DP hotspot results by Schneider the remaining life is likely to be around 5 years at best. It may fail sooner if a through fault were to occur and damage the transformer windings.

It is a proven fact that once the insulation reaches <500 DP it will deteriorate faster as it is at this stage that the cellulose fibres are weakened and the oxidising oil will act as a catalyst to further increase the rate of deterioration. The paper strength is key to the ability of the transformer to withstand through faults or system short circuits. If the paper is weak, then the transformer is likely to suffer damage with each system event until eventually it fails completely. Transformer 1 has the lower DP with an average value of 139 (measured in 2024) and Transformer 2 has an average DP value of 150. These values were derived by the Schneider Electric EcoStruxure Transformer Expert software that provides a detailed assessment and trend of the transformer's health condition based on factual evidence from field testing and monitoring. The DP is the measure of the strength of the paper and at levels below 200DP the transformer is at risk of failure.

The IEEE Standard C57.100 -2022 in Clause 4.4 Criteria for end-of life, states:
"In a transformer, the life of an insulation system ends when the degradation of the solid insulation has progressed to a point such that it fails dielectrically, thermally, or mechanically. The point of failure is considered end-of-life.

For the insulation system materials tests described in this standard, a wide variety of test parameters could be considered for evaluation, and correspondingly a wide variety of end-of-life criteria chosen. Examples of this wide variety are shown in IEEE Std C57.91 and include 50% tensile strength, 25% tensile strength, and 200 degree of polymerization (DP)."

As paper is directly affected by both the acidity and oxidation (low IFT) it can be stated that these transformers will continue to deteriorate rapidly over the next few years and if a through fault were to be experienced then they are likely to fail due to a lack of mechanical strength.

The options are to replace the units with a new transformer, refurbish the existing transformers, maintain them for another 5 to 10 years then replace or do nothing and run to failure. The last option should not be considered as this places the reliability of supply from the substation at risk. It also does not prevent a catastrophic failure where a fire is involved. Therefore, this option will not be considered.

i. **Replace the existing transformers with new:** A new transformer will take in the order of 18 to 24 months to procure, and this is on top of the writing of a specification and tendering process. The latter are available the total time from approval to proceed to delivery is likely to be in the order of 30 months. At present transformer prices these transformers at 20/30MVA 66/22kV are in the order of $2.1Million (installed) each. This cost does not include any site modifications, cable replacements or control wiring replacements, nor changes to protections systems which would all be required.

ii. **Refurbish the existing transformers:** To do a full refurbishment, the scope would need to include a change of oil, if the oil is valued at approximately $2.8 per litre, then this is 25,000 litres of oil in each transformer and a cost of $70,000. The environmentally acceptable disposal of the old oil is an added cost at approximately $1.3 per litre (or $32,500). The cost to refurbish a transformer including dry out and internal clamping along with painting etc (based on similar units refurbished in NSW in 2023) is approximately $1.7 million and carried out over a period on 4 to 5 weeks each. This is provided the work can be done on site. This means that the cost to refurbish the transformers is in the order of $1.8Million and the additional life is likely to be at most another 5 years maximum (based on current very low DP results). This is approximately 81% of the cost of a new unit and the return would only be over 5 years.

    It should be noted that in a refurbishment like this the winding paper is dried out. A dry out will always reduce the DP further due to the excessive heat applied to remove moisture. Therefore, the deteriorated paper which is already at a level that it is very weak and fibrous will only deteriorate further and increase the risk of a winding failure.

iii. **Maintain to end of life in 5 years:** This would be by far the cheapest option; however, it does not address the quality of the oil, nor the risks associated with deteriorated insulation. If the oil was changed then the cost would likely be approximately $100,000 (new + disposal) along with the labour and equipment to do the work at approximately $350,000 over 2 weeks (drain, flush, repair gaskets, fill circulate and test). This means that an initial investment in the order of $500,000 per transformer is needed. This is approximately 24% of a new unit and likely to have additional maintenance until they either fail or replaced. The investment would be only to slightly reduce the risk of a failure associated with the oil. It does not and cannot address the low paper strength with the insulation in the windings. The investment would slow the end-of life process only very slightly, but it would still be expected that these transformers will need to be replaced within the next 5 years, if they do not fail beforehand.

It should be noted that the above applies to the Transformer Nos. 1 and 2 whereas Transformer No.3 is in reasonable condition and would ideally be best served as a system spare. The transformer does not have the same risk of failure but could be relocated to another site if necessary. Replacing all three transformers would allow a new site to have the highest reliability possible for the customers being served. By using the Transformer 3 as a system spare Jemena would have a reliable option to quickly recover the loss of any transformer at almost any Jemena ZSS site, which is an option they currently do not have.

2.1.2. Transformer Risk and Failure Probability - General

Most power transformer failures are generally believed to be random, and failures can occur at any age or under any circumstance. Good statistical data on failure rates or the probability of a failure is almost always not available for any given system or throughout the electric utility industry. Organisations such as CIGRE and IEEE have tried to support the gathering of such data to help the industry understand how and when these failures might occur.

A failure rate is often calculated by taking the annual number of failed units and dividing it by the total number of units on the system. Any utility may be able to gather that data within their own network, but it is more difficult to gather on a national scale. Transformers are highly reliable and typical failure rates according to CIGRE are from 0.5% to 2.0%. These statistics are often used by the asset managers to estimate the probable number of units that will need to be replaced due to failure during any budget year and calculate the likelihood of carrying a spare for any given transformer size and rating within their network.

Beyond this rough estimation method, a failure rate provides very little added value in assessing the likelihood of a specific transformer in the network failing. There is no doubt that all transformers fail in time, but they are more likely to fail when they are old as is the case with the Jemena CN ZSS transformers. If a transformer has a design defect, is poorly maintained, and/or heavily loaded then that will result in accelerating the time to failure. System events such as overvoltage spikes from transients or switching and close in short-circuit faults according to IEEE data, result in approximately 23% of unexpected and premature failures.

Many power transformers survive for sixty or even eighty years. However, the majority of them fail in their middle years. FM Global have published a histogram of typical transformer ages at failure and these are shown in Figure 1 below.

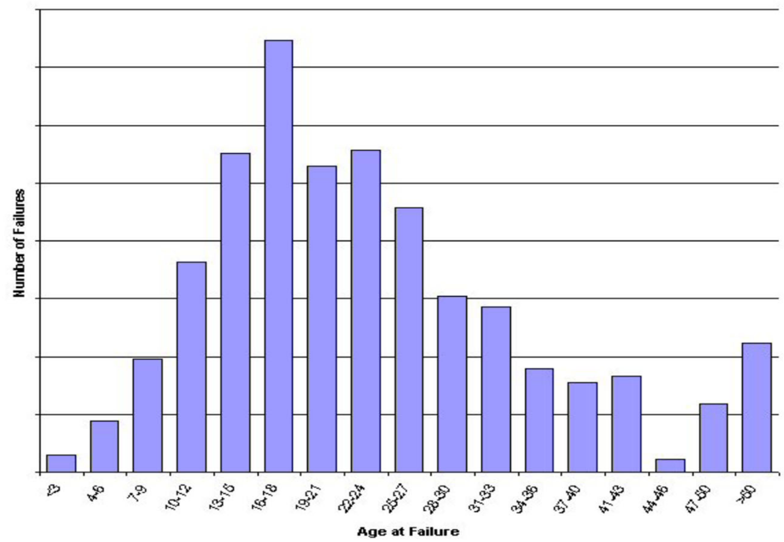


Figure 1| Transformer Failure histogram based on age.

Like other power equipment, transformers have a moderate possibility of failing at start-up (infant mortality), followed by a low possibility of failure during most of their lives, with an increase in failure probability over the last quarter of their operational lives. This characteristic is referred to as the Bathtub Curve as shown in Figure 2 below.

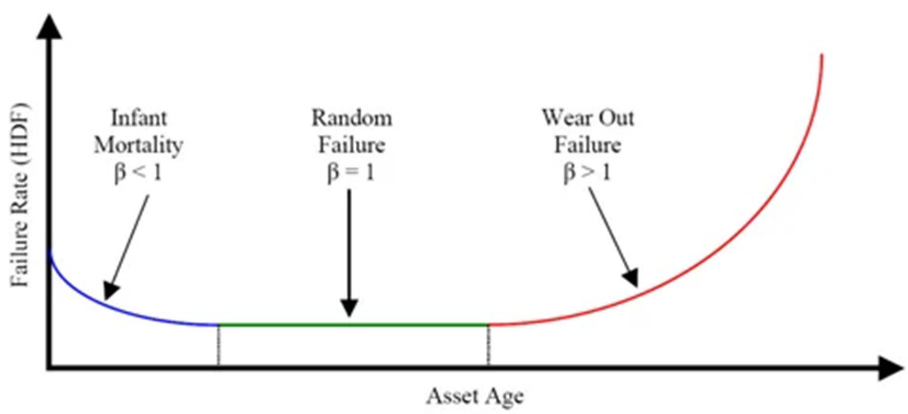


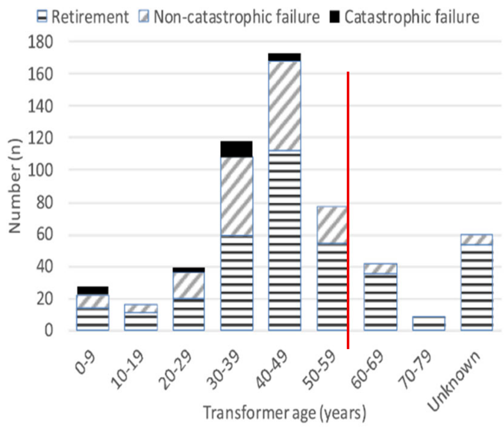
Figure 2| Typical transformer bath-tube curve for failure rates.

When looking at Figure 1 most transformers fail in their middle years which seems to contradict the Bathtub curve in Figure 2. This is not the case because at any point in time, the majority of the transformers (and even switchgear and other assets) on a network are in their middle years. Most mature networks have an average age of between 25 to 35 years (total age of all the assets divided by total number of assets).

In the D. Martin et al paper[1] Figures 1 and 2 as shown below in Figure 3 (of this report), provide some context in times of the number and ages of transformers in the various networks within

[1] *D. Martin, J. Marks, T. K. Saha, O. Krause, and N. Mahmoudi, "Investigation into Modelling Australian Power Transformer Failure and Retirement Statistics" IEEE Transactions on Power Delivery, VOL. 33, NO. 4, AUGUST 2018*

Australia (Figure 2 Martin report) and the number and age of all the failed or retired transformers recorded. CN is marked with a red line in each chart.



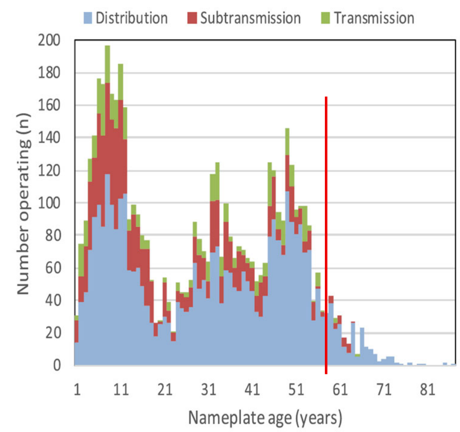


Figure 3| Extracts of Figure 1 (left) and Figure 2 (right) of D. Martin et al paper**.**

To get a better view of any change in probability of a transformer failures, random failures on the system should always be viewed against the age distribution profile and barring any network abnormalities. The above graphs indicate that when the number of failed units is considered within any age group, versus the total units in that respective age group, there is an increase in failure probability with age (like that described by the Bathtub Curve). In these graphs, the number of transformers older than 51 years drops off rapidly but the failure rate is quite high when comparing to the failure rates of transformers in the 1 to 20 year and 30-50-year ranges.

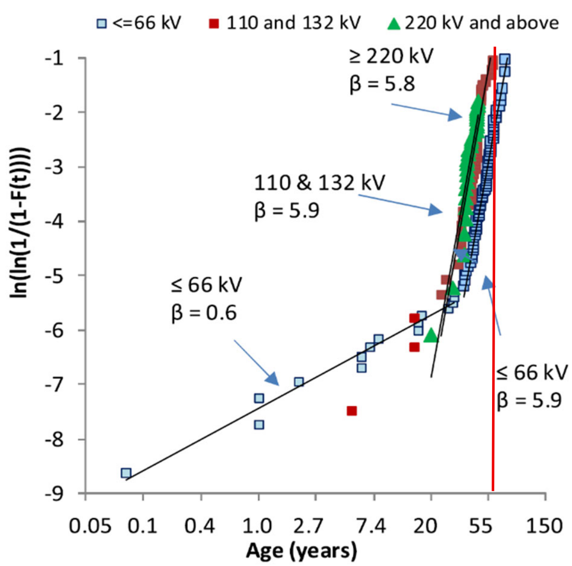


Figure 4| Extract of Hazard Plot Figure 5 of D. Martin et al paper.

This is also better shown by Martin et al, in their hazard plot Figure 5 for failure rates of Australian transformers in poor condition and as provided above. The Jemena CN transformers 1 and 2 age (59 years) are marked with a red line.

It is noted that the failure rates in the ages > 30 years increases rapidly (plotted on a specific log-log scale) because they are age related failures has increased. One take-away from this curve is the level of consistency across all voltage classes as the β is very consistent around the 5.9. The β is a Weibull shape parameter, where β <1.0 is for a decreasing instantaneous failure rate, β =1.0 is where the

Weibull distribution is identical to the exponential distribution and the instantaneous failure rate, and for a β >1.0 is for an increasing instantaneous failure rate.

It is important to understand failure frequency, or the failure rate, applied to the number of transformers in service. Other methods of determining failure frequency are the mean time between failures (MTBF) and the mean time to failure (MTTF). Establishing the change in failure rate with age is difficult but is often required when making decisions about future reinvestment over time. Although it is best to apply statistics from known sources such as in the D. Martin et al paper, some general examples are given in industry literature (eg CIGRE & EPRI documents) and range from 0.5% as being excellent and 2% being acceptable and >2% being unacceptable.

What D. Martin et al, suggests in the paper is that the mean lifetimes of the subtransmission transformer (≤ 66kV) population is approximately 60 years and that the likelihood of an age-related failure starts to increase substantially from the age of 40 years. The paper does highlight there are operational issues that vary the ability of any transformer to reach 60 or more years, and these include, operational loading, design factors, maintenance history, location (environment), system events and so on.

The transformers and to the same extent the switchgear and substation primary plant discussed within this report generally fall within the 55– 65-year range. Therefore, their probability of failure is increasing rapidly. If there is to be a replacement of the equipment, then this is likely to take circa 3 to 5 years to complete which would then have the assets close to the 65-70-year age and at significantly high risk of failure. Additionally, and as explained above the transformers have issues with the IFT and strength (DP) of the paper. As these deteriorate and as seen on the Weibull curve in Figure 4 above the risk of failure will continue to increase substantially.

With the CN ZSS transformers marked with a red line on the curve it is seen that these transformers are in the higher risk end of the curve. Below in Figure 5 the Weibull analysis has been plotted to show the results on a normal scale of Probability of failure against the age of the transformers.

Table 1| Weibull Analysis Increase in PoF Risk each year from 2025

Year Sequence	Year Date	In-Service Failure		Planned Retirement
0	**2025**	**0%**		**0 %**
1	2026	5%		9%
2	2027	11%		19%
3	2028	16%		30%
4	2029	22%		41%
5	2030	28%		53%
6	2031	34%		66%
7	2032	41%		80%
8	2033	47%		95%
9	2034	54%		110%
10	2035	61%		127%
11	2036	68%		144%

The factors used were taken from the D. Martin et al paper and the CN ZSS transformers have been marked on the curves. If the transformers are replaced in 5 years' time, then the curve shows the increasing risk associated with that delay.

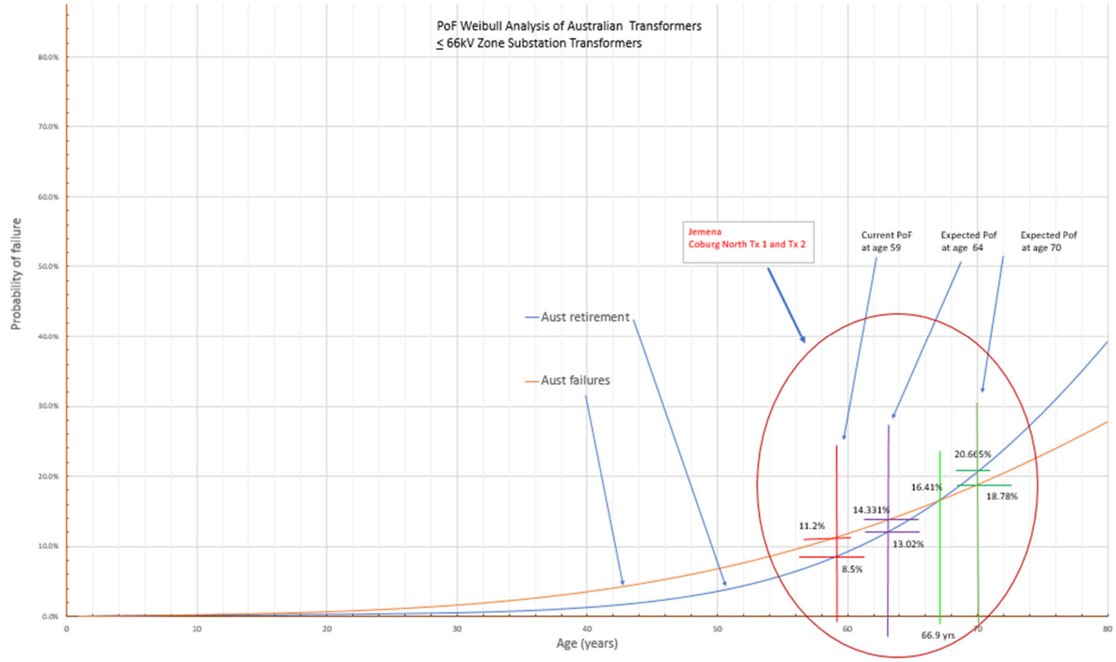


Figure 5| Plot of PoF Weibull analysis for CN transformers

The Weibull analysis above in Figure 5 and Table 1 shows that the risk of an in-service failure increases from 5% in the first year after 2025 to 28% in 5 years and then to 61% in 10 years. This is based on continuing the routine maintenance and doing nothing else.

With a planned retirement, the transformer would be removed from service before it fails. This means that based on the condition of the transformer the owner retires the transformer to prevent the in-service failure and avoid the costs associated with an emergency recovery. The risk of a failure will continue to increase and with these transformers the DP of the paper suggests that the end-of-life has been reached. Therefore, the risk of a failure is substantially higher than the above analysis suggests. These transformers are not in a state where the remaining life that can be recovered or extended any further.

The data was based on the whole of fleet statistics across Australia and did not account for specific failure root causes. It is only that the risk probability is directly related to the total number of transformers at any age. With these transformers the internal condition is very poor and so over the next 5 years they are more likely to fail in service than be retired. A through-fault or over-voltage transient could easily damage either or both transformers beyond repair and reduce the capability of the CN ZSS to provide the required energy to the industrial customers.

Note: The Weibull analysis also shows that the point at which the retirement and failure curves cross is at 66.9 years and a PoF of 16.41%. This point is generally accepted as the point at which the transformers should be retired and is almost 70 years of age. The normal design life or operational life is generally accepted as 40 years but there is more than enough industry experience and proof that transformers do last beyond that to approximately 60 years. There is also enough industry experience and proof that beyond 60 years and with internal paper insulation at <250DP the transformer has reached end of life and will likely fail before 70 years of service.

It is recommended that these transformers (Nos. 1 and 2) be replaced within the next 5 years before they fail and cause significant network disruption.

2.2. Instrument Transformers

The instrument transformers in the CN ZSS are similar in age to the power transformers. These units cannot be checked internally for deterioration other than regular electrical testing. They do not have oil DGA results, and it is not advisable to sample the oil from a hermetically sealed instrument transformer. Therefore, the true internal; condition of the instrument transformers (66kV) is not known. Even though test results show there is not a great deal of change in the electrical results, the quality of the oil and insulation could be poor as not all electrical testing identifies an emerging fault.

The 22kV CTs are an epoxy encapsulated type that is prone to UV damage and cracks over time. This can lead to failures when they reach between 30 and 50 years of service life. The condition of the existing 22kV CTs shows signs of surface deterioration and discolouration which is the start of the process of epoxy degradation.

There is insufficient data on failure rates to be able to plot the probability of failure but it is often acceptable to assume that when a power transformer has aged the associated current and voltage transformers have also aged in a similar way. When an instrument transformer fails it is generally an explosive failure, as seen in recent experience at ElectraNet, Powerlink and Western Power. Whilst ElectraNet and Powerlink instrument transformers were transmission units Western Power experienced ZSS (66 & 132kV) approximately 10 failures between 2013 and 2015 of which 7 were explosive.

There are condition monitoring systems that can be fitted to these units, but they tend to check mostly for Partial Discharge and do not look at other emerging faults. The cost of fitting the monitoring devices at the instrument transformer is reasonably cheap but there is a need to bring the signals back through SCADA and comms systems. The systems modern and there is a need to have the software to do the interpretation. There is a greater expense in implementing a monitoring system, the software and the management of that system at CN ZSS than it would be to replace the instrument transformers with new units that are known to be reliable.

2.3. Disconnectors, Isolators and Earthing Switches

Disconnectors, Isolators and earth switches are generally quite reliable devices; however, they are prone to various failure modes. The FMECA has highlighted a number of these failure modes which include:

- Siezing of operating mechanisms due to corrosion
- Fatigue failures of operating mechanisms and pole insulators due to aging and operational mechanical stresses.
- Worn contacts due to arcing throughout the life of the switch.
- Auxiliary contact failures due to operational wear, environment and aging.

These switches are economical to replace rather than repair, unless the failed switch is located where is may not be safe to replace the whole switch or that a replacement cannot fit in the same location without significant disruption to the switchyard configuration.

Often the earth switches on the disconnectors do not function correctly as they are only used when an outage is required to maintain the assets. Therefore, they may only operate once or twice over a 2-to-6-year period depending on maintenance and outage requirements. Therefore, the earth switch operating mechanisms have a higher failure rate than the main current carrying switch section due to the lack of operation.

Like for like replacements are often used but where a switch is no longer made a new switch with different mounting arrangements is needed and must be adapted.

2.4. 66kV Circuit Breakers

At CN ZSS the 66kV circuit breakers are older bulk oil style similar to that shown in Figure 6 below and were manufactured in 1952 but placed into service in 1966. These breakers were known to contain small levels of PCBs and whilst no immediate information was made available for this report it will be assumed that they contain <9ppm of PCBs. When they fail, it is generally related to the HV bushings, the loss of insulating mediums (paper & oil) or broken/ worn operating mechanisms. They tend to fail either catastrophically or by remaining closed. The later does not cause an explosion or fire as the breaker simply does not open and the system relies on the upstream breaker to clear a fault.

The circuit breakers also have OIP condenser type bushings for connection to the busbars. These bushing like transformer bushings have a finite life and fail in the same manner as the transformer bushings. As they do not see the same loading temperature changes that a power transformer would see during operation, they do last around 10 to 15 years longer than a transformer bushing. International bushing manufacturers have stated that OIP condenser bushings on power transformers have an average life span of 25 years and based on this the circuit breaker bushings should last around 35 to 40 years. This means that these bushings, now at 73 years of age but have been in service for 59 years and are well past the average life span which places them at risk of failure.

The CIGRE Technical Brochures TB509 and TB510 – Reliability of High Voltage Equipment Parts 1 and 2 respectively provide considerable background information on the types of switchgear that is being presented for replacement at these substations. Additionally TB 165 – Life Management of Circuit-Breakers provides data that helps present the risk of failure of this equipment.

The main tank on the breakers has a seal around the base of the lid which tends to deteriorate after 30 years and allows moisture to enter the main oil system. The diagram on Figure 6 below shows the components of a bulk oil circuit breaker and a typical style as used at CN ZSS.

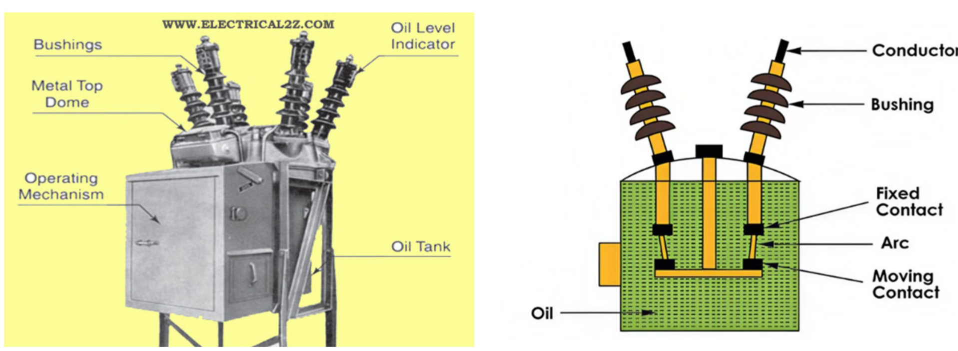


Figure 6|Typical 66kV Bulk Oil CB and Component diagram

As mentioned above there are two major consequences of a failure either an explosive failure or a failure to open. An explosive failure occurs when the moving contacts do not open correctly, or the oil has deteriorated to the point that it no longer can safely extinguish the opening arc. When this happens generally the lid or bushings are ejected under extreme pressure and the oil is expelled. With the oil spray, an arcing fault and air available the result is an explosive failure with a fire.

This type of circuit is no longer manufactured, spare parts are extremely difficult to obtain, the control systems and functions are antiquated and so are somewhat unreliable. They rely mostly on analogue signalling to indicate they have operated. When operating to clear a close-in high energy fault (as opposed to a remote low energy fault), they must be physically checked before they can be closed in case they have sustained damage during the event. Auto-reclose functions are generally not recommended for this type of circuit breaker that has reached beyond 40 years.

If these circuit breakers are replaced, then newer SF6 or other inert gas breakers can be used. For outdoor switchgear they are either live-head or dead-tank breakers both of which would require significant modifications to the substation to be able to fit them in the same location. That is, if one breaker failed and an identical spare is not available, a new modern breaker would need to be installed, and this requires a site reconfiguration.

At Coburg North the risk of a catastrophic failure is increasing with age. However, more importantly is that these breakers are located where an explosive failure could project debris into adjacent commercial buildings on the southern and eastern boundaries or on the northern and western sides onto the public footpaths.

2.4.1. Risk of Failure

To quantify the probability of failure statistics have been taken from the CIGRE international surveys performed by the WG A3.06 which published Technical Brochures TB509 as part of an International Enquiry on Reliability of High Voltage Equipment. The TB510 which is part of the series only discusses SF6 circuit breakers and therefore the reliability statistics used in that TB do not apply here. The TB 509 which is Part 1 – Summary and General Matters, provides the methodology behind the data analytics and this has been used to assess the Jemena CN ZSS circuit breakers.

The two-parameter Weibull distribution is the most widely used distribution for life cycle analysis. As provided for the power transformer analysis the Weibull distribution can be used to model failure data regardless of the asset type and whether the failure rate is increasing, decreasing or constant. It is flexible and adaptable to a wide range of data, and a life cycle distribution can be modelled even if not all of the items have failed.

From this the probability of failure or instantaneous failure rate, of the equipment (based on its physical age) can be estimated by using a Weibull distribution shown in the Equation:

$$\mathrm{f(t)} = \beta.\frac{t^{\beta-1}}{\eta^{\beta}}$$

Where:

t = time, η = characteristic life or scale parameter, and β = shape parameter

The shape parameter indicates the rate of change of the instantaneous failure rate with time. Three ranges of the shape parameter are salient:
- For β = 1.0, the Weibull distribution is identical to the exponential distribution and the instantaneous failure rate, then becomes a constant equal to the reciprocal of the scale parameter, η.
- For β> 1.0, the instantaneous failure rate is increasing; and
- For β < 1.0, the instantaneous failure rate is decreasing.

A shape parameter of β=3.44 is a fair approximation of a normal distribution. The characteristic life, η, is the time at which 63.2% of the items are expected to have failed. This is true for all Weibull distributions, regardless of the shape parameter.

To calculate the β function where AS 61649 provides 63.2% as the value used for η. The equation sets t=η and gives: $F(t) = 1 - e^{-\left(\frac{t}{\eta}\right)^{\beta}} => 1 - e^{-(1)^{\beta}} = 1 - \frac{1}{e} = 0.632.$
The desired life of the switchgear is 50 years however, on page 24 Table 4 of the AusNet Distribution Annual Planning Report 2020–2024 and based on their service life and Regulatory submissions. Clause 3.8.10 of the AusNet report states: "*A Beta (β) value of 3.5 has been used to calculate the failure rates of all assets considered in the zone substation risk-cost model*". They also advise that: "*The condition-based age (t) depends on the specific asset's condition and characteristic life (η), where the characteristic life represents the average asset age at which 63% of the asset class*

population is expected to have failed". AusNet then use an *η* value of 45 for their outdoor circuit breakers.
IT is noted that AusNet distribution substations are at 66kV and therefore can be considered as aligning closely to those 66kV breakers in the Jemena network. This alignment and AusNet verified data can be applied to the Jemena PoF.
Therefore, based on the above data sets the value of $\eta = 45$ and $\beta = 3.5$.

The first step in calculating the Probability of Failure (PoF) of an asset is determining the asset health and associated effective age, which considers that:

a. an asset consists of different components, each with a particular function, criticality, underlying reliability, life expectancy and remaining life. Therefore, the overall health of an asset is a function of these attributes.

b. key asset condition measures and failure data provides information on the current health of an asset, where the current effective age is derived from asset information and condition data. The Jemena 66kV CBs can be considered as being at an effective age of 59 years given they were manufactured and installed in circa 1966.

c. the future health of an asset (health forecasting) is a function of its current health and any factors causing accelerated (or decelerated) degradation of one or more of its components. The future health s affected by system influences such as internal and external electrical stresses, overloads and faults; and

d. the future effective age is derived from the current effective age and based on factors such as, external environment/influence, expected stress events and operating/loading condition.

The PoF is the likelihood that an asset will fail during any given period. The outputs of the PoF calculation are one or more probability of failure times which provide a relationship between the effective age and the yearly probability of failure value. This analysis is performed by using Weibull analysis as stated above. This establishes how likely it is that the asset will fail over time. The Weibull parameters which represent the probability of failure curve for Jemena 66kV Circuit Breakers are $\eta = 45$ and $\beta = 3.5$ as stated above.

There are 54 bulk oil 66kV circuit breakers in the Jemena fleet and CIGRE (Switchgear reliability studies) data suggests that worldwide about 9.42% of any installed fleet will fail over their operating life. Therefore, this equates to approximately 5 circuit breakers over the life span of 69 years.

If the existing age is taken as 59 years, then the curve for the probability of a failure occurring is shown in Figure 7 below.

At present (2025) and based on the age of the circuit breakers there is a 92.4% probability that a bulk oil breaker will fail in the next year. This increases in the next 5 years to 96.76% probability when the breakers reach a 64-year service life. Noting that the breakers were made in or before 1966 and went into service in 1966 when CN was built. The assessment has been made on the service life not the nameplate age which in some instances is before 1966. Nonetheless these breakers are considered to be at a high risk of a failure over the next 12 months and beyond until they are replaced. If allowed to remain in service for the next 10 years until 2035 then the probability of a failure is almost 99% and, in that time, it is likely that at least 1 or more will fail.

The assessment done show that the risk of a failure is high mainly because the size of the fleet is small and the age of the circuit breakers.

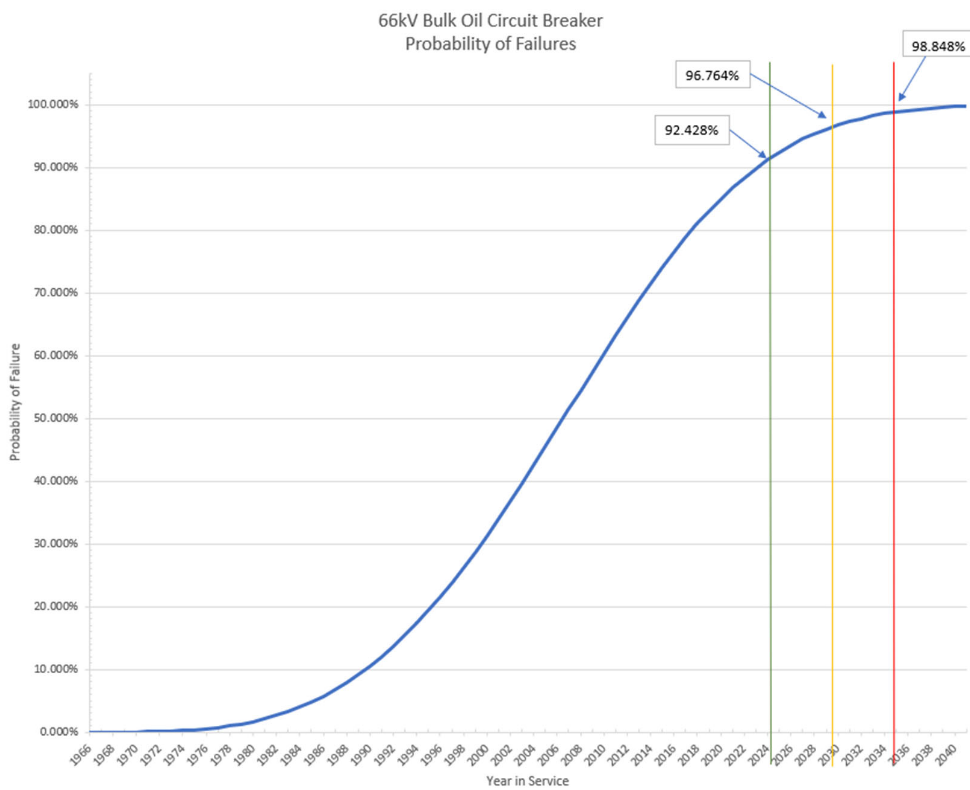


Figure 7|CN ZSS 66kV CB Probability of Failure Curve

2.5. 22kV Outdoor Circuit Breakers/ Switchgear

The 22kV circuit breakers are indoor type breakers housed in individual outdoor enclosures. Figure 8 shows the side view of CN ZSS 22 kV yard and an example of this type of circuit breaker arrangement.

For the purposes of this report and assessments the 22kV circuit breakers will be considered as 22kV switchgear. This is because the arrangements for the breakers being in service requires a similar set up as would be required for an indoor panel type switchboard. The only difference is that these breakers are individual panels and the busbar is external rather than enclosed with the switchgear.

Figure 8|CN ZSS 22kV CBs in switchyard and similar type.

These outdoor types of circuit breaker arrangements were not manufactured as arc fault contained or vented. Therefore, switching of these breakers must be done remotely to ensure operators are not exposed to a possible arcing fault and failure. The internal arrangement of these enclosures has a fixed 22kV circuit breaker, typically a vacuum type connected to exposed busbars that are connected to the roof mounted bushings.

To access the CB control circuits and maintain the unit the breaker must be completely isolated from the network externally to the cubicle. The arrangement does require additional switching steps. Maintaining the breaker in-situ is quite limited and therefore general maintenance is normally done. When substantial maintenance is required, the breaker is removed from the enclosure and maintained in a workshop. If a spare breaker is available, it may be swapped out but as these types of systems are not generally manufactured to the same design spare parts are quite rare and retrofitting a new type of breaker is extremely difficult.

The risks associated with these breakers include ingress of moisture (into the cubicle) and vermin which can cause flashovers internally. In terms of operator risks, there is always an issue with control systems, interlocks and non-operation of the breaker due to the environment. Indoor switchboards do not have the same exposure risks and so less likely to fail to operate due to control wiring deterioration.

As mentioned previously if an entire cubicle and breaker had to be removed using a crane then a significant portion of the substation would need to be isolated to allow safe access.

Replacement of these circuit breakers would be best undertaken by constructing a new switchroom with all breakers and controls etc enclosed in the one building. It may also be possible to do this off site and transport the completed building to site, thereby reducing the time that the substation is offline for the cut-over.

2.5.1. Risk of Failure

As shown in section 2.4 above the ability to quantify the probability of failure requires industry statistics. At the medium voltage level there is not a great deal of data available from recognised international organisations such as CIGRE, but they had information in published session papers. The literature indicated that the failure rates were higher than outdoor circuit breakers because of the number of operations, the cable connection arrangements and level of mechanical components that were susceptible to wear out failures.

What is normal for minimum oil circuit breakers is that their maintenance and most failure modes are very much the same as a bulk oil breaker and on the higher voltages >66kV. Because they have additional operating mechanisms and far higher numbers of operations the failure rates of minimum oil breakers were somewhat higher than the 66kV breakers. The CIGRE data shows failure rates as high as 25% over the life of a switchboard, depending on the country and maintenance practices. Having stated that, the average failure rate was in the order of 1 circuit breaker/panel every 5 years for any given fleet of 50 or more medium voltage circuit breakers switchboards. The failure modes were not confined to the circuit breakers only and hence the higher failure rate than would be for a HV circuit breaker alone.

The data used for assessing these switchboards has been derived from available Jemena SAP data and based on existing fleet of 22kV Switchboards and total number of CBs in those boards. 158 Items and failure rate (based on CIGRE industry norms) is 15 units in 75 years or 0.2 failures per annum ie 1 every 5 years on average.

There were 158 Jenema 22kV minimum oil breakers in their network of which 94 remain in service. If the CIGRE switchgear reliability failure rate for medium to low voltage switchgear (>66kV & <6.6kV) of 1 every 5 years is applied to Jemena's fleet, then this will equate to a total of 12 circuit breakers in a period of 63 years (oldest breakers were installed in 1962).

Using these statistics the β shape parameter value was calculated by the slope of the Weibull log-log plot shown below in Figure 9. The best fit line was y=1.0164x+11.896 which provided the shape parameter of 1.0164. Using this shape parameter the characteristic life or scale parameter η was then calculated using the WeiBayes analysis algorithm (from AS61649):

$$\eta = \left[\sum_{i=1}^{N} \frac{t_i^{\beta}}{r} \right]^{1/\beta}$$

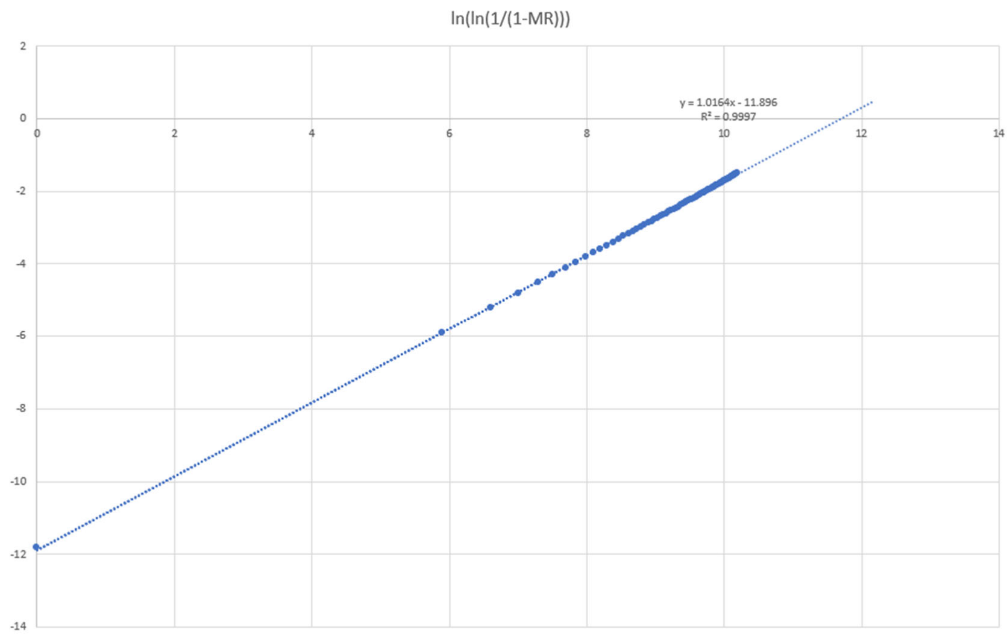


Figure 9|CN ZSS 22kV switchboard Weibull shape parameter

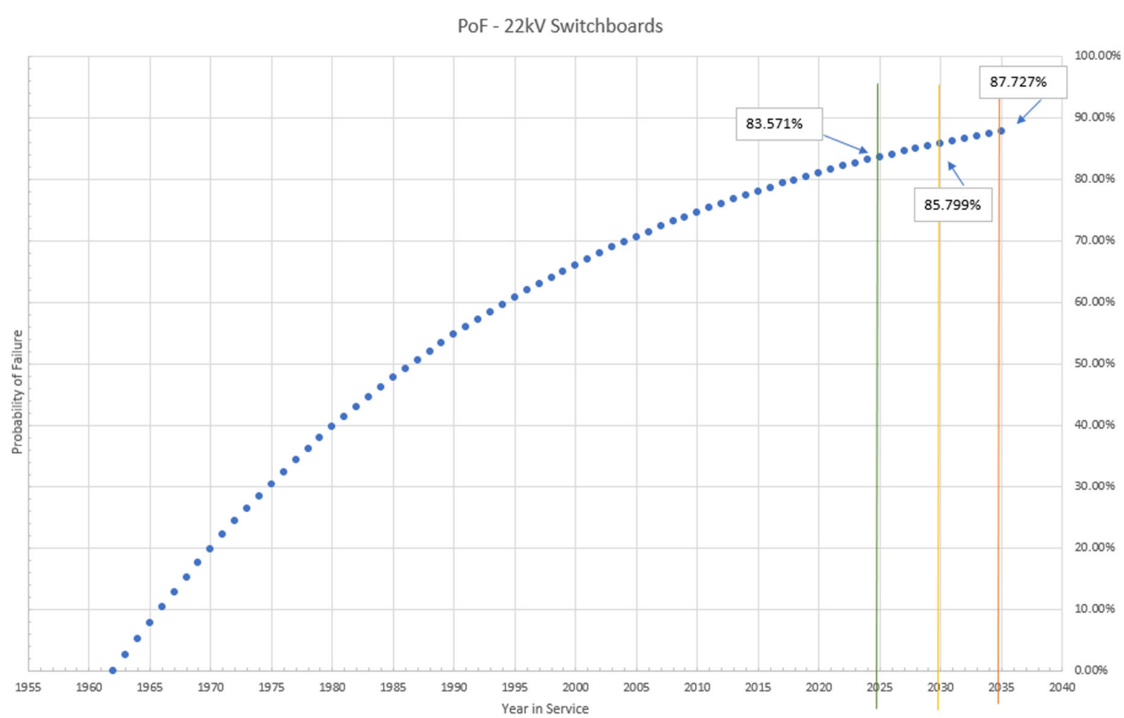


Figure 10|CN ZSS 22kV CB Switchboard Probability of Failure Curve

Figure 10 above is the Weibull probability for the 22kV circuit breaker switchboards.

In the present state there is a 83.57% probability that Jemena will have one of these old 22kV CB panels fail in the next 12 months. If the breakers are not retired by age 73 then that probability of failure will increase to 87.73% probability of a failure in that year.

Whilst these values are quite high, they represent the risk associated with the age of the switchgear. If reviewing this with respect to the typical bathtub curve as per Figure 2 and repeated in Figure 11 below, the switchgear has entered the wear out phase of the curve. This means that it now has a more finite end of life and that the risk of a failure continues to increase sharply.

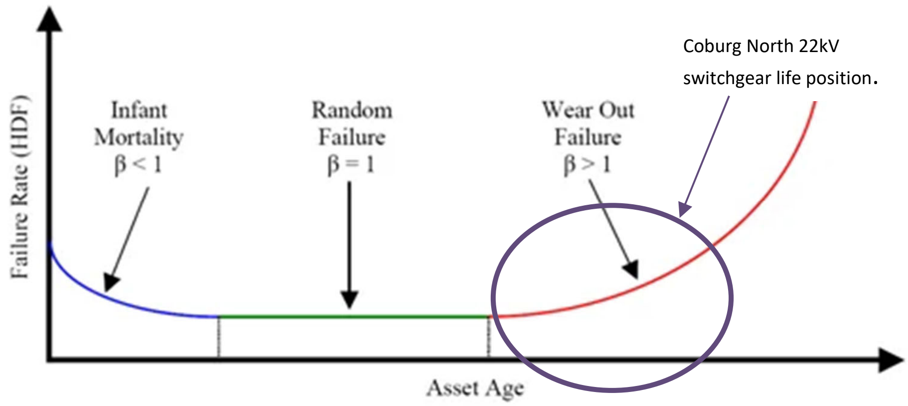


Figure 11| Typical transformer bath-tube curve for failure rates.

Additionally, these breakers are operated and maintained by switching operators and field staff. When at the panel there are areas within each panel that can remain energised and this is a safety risk which Jemena must manage. It requires additional switching to isolate the units remotely and then additional safety checks to ensure there is minimal risk of arc flash. These extra steps taken additional time which is added to the overall cost of the maintenance. The level of maintenance must also increase as the switchboards are in the wear out stage of life. This means that the cost of maintenance overall increases and the disruptions for that maintenance (and any failure) to end customers increases also.

2.6. Protection Relays and Control equipment

The Coburg North ZSS was constructed using electro-mechanical protection relays and many of these remain in service at the site. Whilst they are very reliable relays very few technicians fully understand how they work and how they are to be set. The relays have a flag reset and when one operates the flag stays down until manually reset. This means that an operator must travel to site and reset the flag so that the relay can function correctly on the next event.

These relays do not have any data recording capability and therefore other systems must be added to the network to log any events and allow engineers to interrogate the data to locate the fault or understand the magnitude of the event. Without such capabilities it limits the ability of the network controller to re-instate the supplies quickly. It requires deployment of field staff to assess the extent of any fault and advise if it is acceptable and safe to re-energise.

This means that the supply to customers remains off or at risk until the network interrogation has been completed. In modern more digital type substations this information is readily available, and the restoration time is greatly reduced thereby providing customers with the required service levels expected.

Therefore, replacement of these relays should be undertaken. If it were done as a stand-alone project, it would require staged outages within the substation, replacing of control cabling, installation of new panels and control equipment. The current control room on site is not adequate for such a replacement project and therefore a new control / relay room would also be necessary.

2.7. Conclusion for Coburg North ZSS

Jemena have proposed a redevelopment of the CN ZSS by installing standardised equipment to replace the ageing and at-risk primary and secondary assets. Their proposal includes the replacement of:

- Three 66kV circuit breakers
- Three 20/33MVA 66/22kV transformer
- One modular control room
- Three modular 22kV switch rooms
- An earth fault management system
- New protection and control equipment.

Based on the assessments made above in this Section 2 the replacement of the aged equipment is required before equipment failures start affecting the reliability of supply to customers.

The transformers (Nos 1 and 2) are nearing the end of operational life, and the oil quality, paper strength and moisture contents have deteriorated to the point where significant work must be done to prevent a failure. The work required is almost the same cost as new transformers and the life extension would not likely give a further 10 years of service based on the paper DP and moisture content.

The 66kV circuit breakers are bulk oil type and like the transformers they protect, they are nearing their end of life and if a failure were to occur it would likely impact the associated transformer. The breakers have a greater than 92% probability of one unit failing in any given year. If any one of the transformers failed it may create a situation that the 66kV breaker could not manage the fault current and so fail as well.

The 22kV switchgear at the site comprises indoor circuit breakers in individual outdoor cubicles connected to outdoor exposed busbar systems. This design has long been made obsolete as it poses safety risks to maintenance workers, has a higher risk of unplanned outages due to its exposure, and requires significantly more real estate in its construction. Therefore, a new 22kV switchroom with new indoor 22kV arc-fault rated switchgear will offer greater safety and reliability for a smaller footprint. The calculated PoF is >80% and so these circuit breakers pose a real risk to any operator.

With the transformers, 22kV and 66kV switchgear, the protection scheme would also require upgrading. A Weibull failure analysis has not been performed on this as it is more relevant that it be replace with the switchgear to which it is linked. As stated, the protection relays are mostly old electro-mechanical relays and to replace them requires significant re-wiring of the protection and control schemes. This is best undertaken with the switchgear replacements and housed in a new section of a new 22kV switchroom. The benefit here will be that Jemena can utilise its SCADA and communications systems to manage any unplanned outage event remotely rather than having to have additional outage time due to the disadvantages with type of equipment at site.

Much of the remainder of the substation equipment (busbars, disconnectors insulators etc) would be replaced with the construction of a new substation. This would enhance the safety and reliability of the site for the 24,000 customers and allow for the managing of the impact of increasing levels renewables on the network.

The recommendation is for a total substation replacement to ensure a safer and more reliable supply to customers. If the substation is not replaced, then it will have an increasing risk of primary plant failures that will cause widespread outages for the customers. The loss of any one transformer will not be supported by a spare or be replaced until a new transformer is procured. This can take around 18 to 24 months from the time of placement of an order and so in that time the loads will need to be transferred and that places additional risk on the other transformers and primary plant.

3. COBURG SOUTH ZONE SUBSTATION

The Coburg South Zone Substation (CS ZSS) is an indoor substation. The 66kV switchgear is outdoor type but positioned inside the substation building.

Jemena have advised that they are requiring to redevelop the CS ZSS by installing standardised equipment to replace ageing and at-risk primary and secondary assets. The assets under consideration for replacement include:

- One 66 kV circuit breaker
- Two 22kV switchboards
- An earth fault management system
- New protection and control equipment.

3.1. 66kV Circuit Breaker

At Coburg South there is one 66kV Circuit Breaker that is at risk of failure, and it is the bus-tie breaker between the 66kV No1 bus and 66kV No. 2 bus. The breaker is an AEI type LG4C/66G bulk oil circuit breaker placed in service circa 1976. The Jemena risk assessment showed the circuit breaker as a high risk, due to it having reached its end of operational life. The consequences of a failure of the breaker were stated as:

- Unable to operate the breaker as intended
- Auto reclose and manual close control of the breaker are compromised.

- Loss of supply to a high profile HV customer and residential customers.
- Fault current through the 66kV lines will be higher with the 66kV loop open (lines are not in parallel) which may result in CT saturation, causing protection maloperation with possibility of a station black.
- Negative reputational impact
- Regulatory investigations

K-BIK power has done an additional FMECA that breaks down many of these consequences and ties them to specific failure modes. The total risk remains as high with the worst risk being when a CB pole fails and it compromises the insulator. In this scenario the oil within the aged CB is expelled and causes a fire within the building.

The risk of a fire is significant in this situation in that if it occurs with the building it can set fire to other equipment or the building. If a fire starts within the building it would place every part of the substation at risk and so needs to be avoided wherever possible. The fire would not be able to be managed by the fire fighters until the substation is de-energised, and this means there is a further delay allowing the fire to do more damage.

A fire suppression system can be used but again this can have an adverse effect on other equipment within the building and so a total loss of the ZSS would be the initial outcome until all equipment can be checked for serviceability. It means that the site is at risk of being offline for an extended period and unable to supply the 24,000 customers it normally services.

The cost to replace this 66kV Circuit Breaker would be in the order of $500,000. If the CB were to fail and a small fire was encountered but no significant damage, then the cost to Jemena would be far greater than that of just the circuit breaker. There would be at least 2 days where the clean-up and equipment checks would need to be undertaken. The site is capable of 60MVA of load and the loss of that load, transferring the load to other sites to re-instate 24,000 customers, and the emergent replacement of the breaker would be more than $4 million. Therefore, the most cost benefit solution would be to replace the circuit breaker before it fails.

In Section 2 of this report a Weibull analysis of the probability of a failure of a 66kV circuit breaker was undertaken. The analysis holds for this site as well because that analysis was done based on the installed population at Jemena rather than a site-by-site option. Therefore, the risk of a failure of a 66kV circuit breaker is at >92% probability. Whilst this is high it is due to the age and number of breakers across the Jemena network. As these breakers age the probability of an aged, related failure will only increase and so they should be replaced at the earliest opportunity.

3.1. 22kV Switchboards

The existing CS 22kV switchboard is a Sprecher and Schuh, indoor minimum oil circuit breaker type HPtW306fs and installed in 1976. This places the switchboard at an age of 49 years, and the common life span of an indoor switchboard is approximately 50 years. This places the switchboard at the end of its normal operating life.

Figure 12 shows the switchboard arrangement and the photo on the right shows the inside of the CB cubicle. This switchboard is not arc-fault contained, or arc-fault vented. As can be seen the circuit breakers are racked into the switchboard manually by pushing them in. Once inside they can then be reconnected and the front panel covering the CB controls acts as a door.

The risk is when the breaker is racked out or racked in there is at least one side of the busbar (inside the spouts) that is alive. If there is a fault at the time of racking, then the switching operator is at risk of experiencing an arcing fault. These breakers are a minimum oil type and so any arcing fault is likely to ignite the oil and cause a fire.

The switchgear has been maintained but the maintenance records are now showing that many breakers are starting to leak and need oil replacements.

Figure 12|CS ZSS 22kV Switchboard.

Modern arc fault contained and vented switchboards only allow the operator to rack the breakers when the bolted arc fault tested door is fully closed. This way if an arc fault occurs it does not expose the operator to the same level of risk.

As per the Coburg North ZSS the 22kV circuit breakers are a high risk and have a >80% probability of a failure within the installed fleet. It also follows that if one CB fails and the damage is substantial then the adjacent CBs may also be damaged beyond repair and creating a situation where a full bus section with feeders could be permanently out of service until it is replaced. Given this switchboard is aged at 49 years the probability of it failing is lower and closer to 75% but will rise rapidly as it ages ie between 49 and 54 years it will increase to >79% which is a 5% increase in probability over a 5 year period and the PoF at 59 years of age is >81.5% which is a total increase of 8% in 10 years.

This may not seem to be a significant increase in risk but as the switchboards are near the end of operational life the increase in probability at the later stages of life does increase because it is getting closer to total failure.

3.1.1. CS Switchboard Condition and Consequences

The CS 22kV switchboard has been tested and is being monitored for high levels of Partial Discharge (PD) and low Insulation Resistance (IR) levels in a few cubicles. These are managed by regular cleaning and checks on joints and insulation condition.

According to the maintenance records it seems the PD returns after 8 to 10 months and so planning of another outage to manage it is undertaken. Additionally, the DLA results have shown some adverse changes that indicate the switchgear is deteriorating with time. This can also be due to the oil seal deterioration and leaks. If moisture gets in and the oil leaks out there is a risk that the breaker will either not operate correctly or that an operating arc could ignite the low level of oil remaining and cause an explosive failure.

A normal switchboard should only be taken out of service approximately once every 2 to 6 years for routine maintenance on circuit breakers and operating components. These switchboards are taken offline every 12 months and so the cost and risk are climbing with each outage.

The control wiring within the circuit breakers is older exposed type wiring (refer Figure 13). The control breakers and switches are older bakelite type which are no longer manufactured. These are electro-mechanical devices and when a control circuit issue arises it is difficult to trace. The components must be obtained from other old unserviceable breakers to ensure they operate as intended. Retrofitting new devices is not an option as the way these devices trigger a trip or close of the breaker is very specific to the manufacture of the breaker.

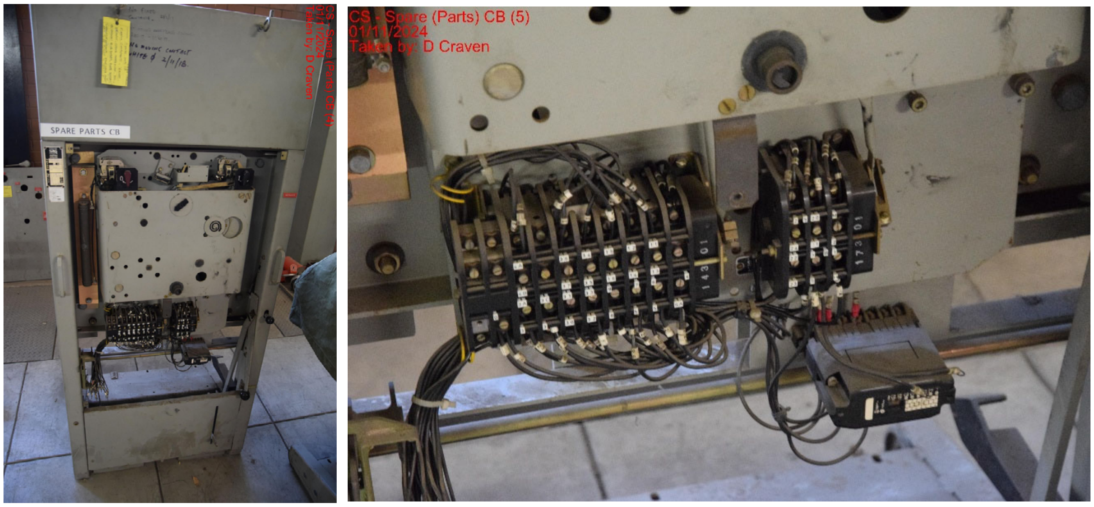


Figure 13|CS ZSS 22kV Circuit Breaker Control Wiring

To perform the testing, all the circuit breakers on one side of the Bus-tie breaker must be removed from service. Once tested then the other bus with be taken offline to perform the testing. This involves substantial switching and load transfers all of which have a high level of risk.

If the switchboard were replaced, then the switching operations would be simpler and lower risk. Additionally, there would not be a need to have as many outages to maintain the boards. This presents a substantial saving in maintenance costs and unserved energy to the customers.

As with the main 66kV breaker there is an arcing fault inside the switchboard then at least one of the two bus sections will be out of service. This would be either permanently out of service or temporarily until repairs can be made. Either way, the feeders would not be in service, and loads would need to be transferred. To do repairs or replace the failed switchboard after an arcing fault would mean taking the entire switchboard offline and that would mean the substation would be effectively offline. Again, the load is transferred, and other substations are placed at higher risk if another contingency were to occur at once of those sites.

Whilst the cost of a new 22kV switchboard is quite high (approx. $130K per panel) the cost is off set by the savings in maintenance and lower risk of loss of supply to the 24,000 customers the substation services.

3.2. Protection and Control Equipment

As per Coburg North, Coburg South ZSS was constructed using electro-mechanical protection relays and many of these remain in service at the site. Whilst they are very reliable relays very few technicians fully understand how they work and how they are to be set. The relays have a flag reset and when one operates the flag stays down until manually reset. This means that an operator must travel to site and reset the flag so that the relay can function correctly on the next event.

These relays do not have any data recording capability and therefore other systems must be added to the network to log any events and allow engineers to interrogate the data to locate the fault or understand the magnitude of the event. Without such capabilities it limits the ability of the network controller to re-instate the supplies quickly. It requires deployment of field staff to assess the extent of any fault and advise if it is acceptable and safe to re-energise.

This means that the supply to customers remains off or at risk until the network interrogation has been completed. In modern more digital type substations this information is readily available, and the restoration time is greatly reduced thereby providing customers with the required service levels expected.

Therefore, replacement of these relays should be undertaken. If it were done as a stand-alone project, it would require staged outages within the substation, replacing of control cabling, installation of new panels and control equipment. The current control room on site is not adequate for such a replacement project and therefore a new control / relay room would also be necessary.

3.3.Conclusion for Coburg South ZSS

Jemena have proposed a redevelopment of the CS ZSS by installing standardised equipment to replace the ageing and at-risk primary and secondary assets. Their proposal includes the replacement of:

- One 66 kV circuit breaker (Bus-tie)
- Two 22kV switchboards age Sprecher & Schuh switchboards
- An earth fault management system
- New protection and control equipment.

Based on the assessments made above in this Section 3 the replacement of the aged equipment is required before equipment failures start affecting the reliability of supply to customers.

The 66kV circuit breaker is a bulk oil type and the bus-tie breaker between the two CS power transformers. The breaker like those at CN ZSS is nearing its end of life and if a failure were to occur it would impact the substation transformers and likely cause a fire within the building. Any fire within the building is a serious risk to all the equipment as well as the workers.

The 22kV switchgear at the site comprises indoor minimum oil circuit breakers. This design has long been made obsolete as it poses safety risks to maintenance workers, has a higher risk of arc fault exposure with fire involved. New indoor 22kV arc-fault rated switchgear will offer greater safety and reliability for a smaller footprint. It would allow the site to be expanded to meet any future needs for additional feeders.

The protection relays are mostly old electro-mechanical relays and to replace them requires significant re-wiring of the protection and control schemes. This is best undertaken with the switchgear replacements as it can be wired to suit the new switchgear control system. The added benefit here will be that Jemena can utilise its SCADA and communications systems to manage any unplanned outage event remotely rather than having to have additional outage time due to the disadvantages with type of non-arc-fault rated equipment at site.

These replacements would enhance the safety and reliability of the site for the 24,000 customers and allow for the managing of the impact of increasing levels renewables on the network and allow expansion of the substation in the future.

The recommendation is for these assets to be replaced to ensure a safer and more reliable supply to customers. If they are not replaced, then it will have an increasing risk of primary plant failures that will cause widespread outages for the customers due to fires or total loss of the asset. The loss of any one 22kV circuit breaker could damage the bus-section that it is connected to. It is not necessarily supported by a manageable spare, and the control components are no longer available. Replacement switchboards can take around 18 months to manufacture from the time of placement of an order and so in that time the loads will need to be transferred. This would place additional load and so higher risk on the other primary plant or nearby substations.

4. NORTH HEIDELBERG ZONE SUBSTATION

The North Heidelberg Zone Substation (NH ZSS) is an indoor substation like CS ZSS where the 66kV switchgear is outdoor type located inside the substation building.

Jemena are proposing to redevelop the NH ZSS by installing standardised equipment to replace ageing and at-risk primary and secondary assets. Key assets for replacement include:

- Two 66kV circuit breakers for transformer 66kV bus ties
- Three 22kV switchboards (3 bus-sections comprising approx 22 panels)
- An earth fault management system
- New protection and control equipment.

The NH ZSS supplies 16,000 customers within the Jemena network and has equipment very much the same as that at Coburg South excepting it is a three (3) transformer substation.

4.1.66kV Circuit Breakers

At North Heidelberg there are two 66kV bus-tie Circuit Breakers that is at risk of failure. They are AEI type LG4C/66G bulk oil circuit breakers placed in service circa 1973 which makes these breakers 52 years old. The Jemena risk assessment showed the circuit breaker as a high risk, due to it having reached its end of operational life. The consequences of a failure of the breaker were stated as:

- Unable to operate the breaker as intended
- Auto reclose and manual close control of the breaker are compromised.
- Loss of supply to a high profile HV customer and residential customers.

- Fault current through the 66kV lines will be higher with the 66kV loop open (lines are not in parallel) which may result in CT saturation, causing protection maloperation with possibility of a station black.
- Negative reputational impact
- Regulatory investigations

K-BIK Power has done an additional FMECA that breaks down many of these consequences and ties them to specific failure modes. The total risk remains as high with the worst risk being when a CB pole fails and it compromises the insulator. In this scenario the oil within the aged CB is expelled and causes a fire within the building.

The risk of a fire is significant in this situation in that if it occurs with the building it can set fire to other equipment or the building. If a fire starts within the building it would place every part of the substation at risk and so needs to be avoided wherever possible. The fire would not be able to be managed by the fire fighters until the substation is de-energised, and this means there is a further delay allowing the fire to do more damage.

A fire suppression system can be used but again this can have an adverse effect on other equipment within the building and so a total loss of the ZSS would be the initial outcome until all equipment can be checked for serviceability. It means that the site is at risk of being offline for an extended period and unable to supply the 16,000 customers it normally services.

The cost to replace each 66kV Circuit Breaker would be in the order of $500,000. If the CB were to fail and a small fire was encountered but no significant damage, then the cost to Jemena would be far greater than that of just the circuit breaker. There would be at least 2 days where the clean-up and equipment checks would need to be undertaken. The site is capable of 90MVA of load and the loss of that load, transferring the load to other sites to re-instate 16,000 customers, and the emergent replacement of the breaker would be more than $4 million. Therefore, the most cost benefit solution would be to replace the circuit breaker before it fails.

The PoF aligns with that of the CN circuit breakers however, as these units are indoor, they do present a greater risk of consequential damage as stated above. This additional risk is not quantified here and relates specifically to where the assets are physically located. Inside buildings the additional risks are associated with fires and people in the immediate working area.

4.2. 22kV Switchboards

The existing NH 22kV switchboard is a Sprecher and Schuh, indoor minimum oil circuit breaker type HPtW306fs and installed in 1974. This places the switchboard at an age of 51 years, and the common life span of an indoor switchboard is approximately 50 years. This places the switchboard at the end of its normal operating life.

Figure 14 shows the switchboard arrangement and the photo on the right shows the inside of the CB cubicle with the bus-shutters. This switchboard is not arc-fault contained, or arc-fault vented. As per the CS switchboard, the circuit breakers are racked into the switchboard manually by pushing them in. Once inside they can then be reconnected and the front panel covering the CB controls acts as a door (refer Figure 14 on the left-hand side).

The risk is when the breaker is racked out or racked in there is at least one side of the busbar (inside the spouts) that is alive. If there is a fault at the time of racking, then the switching operator is at risk of experiencing an arcing fault. These breakers are a minimum oil type and so any arcing fault is likely to ignite the oil and cause a fire.

The switchgear has been maintained but the maintenance records are now showing that many breakers are starting to leak and need oil replacements.

Modern arc fault contained and vented switchboards only allow the operator to rack the breakers when the bolted arc fault tested door is fully closed. This way if an arc fault occurs it does not expose the operator to the same level of risk.

Figure 14| NH ZSS 22kV Sprecher & Schuh Switchboard

The PoF has been calculated for the 22kV switchboard as per Section 2 above, but this switchboard is 51 years old and therefore the PoF on the curve is at 78.8%. In 5 years this will have increased to 88.35% which is an overall increase of 10.8% above the current risk level. The boards are fast approaching end of life and have entered the wear-out phase of the bathtub curve.

4.2.1. NH Switchboard Condition and consequences

The North Hiedelberg 22kV switchboard has been tested and is being monitored for high levels of Partial Discharge (PD) and low Insulation Resistance (IR) levels in a number of cubicles. These are managed by regular cleaning and checks on joints and insulation condition. The PD has been recorded at levels above 700pC which is dangerously high. After maintenance is reduced but by only a few hundred pC. The normal in-service limit is generally accepted as <250pC for this type of switchgear.

According to the maintenance records it seems the PD returns after 6 months and so planning of another outage to manage it is undertaken. Additionally, the DLA results have shown some adverse changes that indicate the switchgear is deteriorating with time. This can also be due to the oil seal deterioration and leaks. If moisture gets in and the oil leaks out there is a risk that the breaker will either not operate correctly or that an operating arc could ignite the low level of oil remaining and cause an explosive failure.

A normal switchboard should only be taken out of service approximately once every 2 to 6 years for routine maintenance on circuit breakers and operating components. These switchboards are taken offline every 12 months and so the cost and risk are climbing with each outage.

The control wiring within the circuit breakers is older exposed type wiring the same as in CS ZSS switchgear (refer Figure 13). The control breakers and switches are older bakelite type which are no longer manufactured. These are electro-mechanical devices and when a control circuit issue arises it is difficult to trace. The components must be obtained from other old unserviceable breakers to ensure they operate as intended. Retrofitting new devices is not an option as the way these devices trigger a trip or close of the breaker is very specific to the manufacture of the breaker.

To perform the testing, all the circuit breakers on one side of the bus-tie breakers must be removed from service. That is, the end bus-sections would have 1 bus-ie open & removed whereas the centre bus-section 2 has both bus-tie breakers removed. Once tested then the next bus-section is taken offline to perform the testing. This involves substantial switching and load transfers all of which have a high level of risk.

If the switchboard were replaced, then the switching operations would be simpler and lower risk. Additionally, there would not be a need to have as many outages to maintain the boards. This presents a substantial saving in maintenance costs and unserved energy to the customers.

As with the main 66kV breakers there is an arcing fault inside the switchboard then at least one of the three bus sections will be out of service. This would be either permanently out of service or temporarily until repairs can be made. Either way, the feeders would not be in service, and loads would need to be transferred. To do repairs or replace the failed switchboard after an arcing fault would mean taking the entire switchboard offline and that would mean the substation would be effectively offline. Again, the load is transferred, and other substations are placed at higher risk if another contingency were to occur at once of those sites.

Whilst the cost of a new 22kV switchboard is quite high (approx. $130K per panel) the cost is off set by the savings in maintenance and lower risk of loss of supply to the 16,000 customers the substation services.

4.3. Protection and Control Equipment

As per Coburg North and Coburg South, the North Heidelberg ZSS was constructed using electro-mechanical protection relays and many of these remain in service at the site. Repeating what has been stated previously for each of the other two substations:

The old relays are very reliable but very few technicians fully understand how they work and how they are to be set. The relays have a flag reset and when one operates the flag stays down until manually reset. This means that an operator must travel to site and reset the flag so that the relay can function correctly on the next event.

These relays do not have any data recording capability and therefore other systems must be added to the network to log any events and allow engineers to interrogate the data to locate the fault or understand the magnitude of the event. Without such capabilities it limits the ability of the network controller to re-instate the supplies quickly. It requires deployment of field staff to assess the extent of any fault and advise if it is acceptable and safe to re-energise.

This means that the supply to customers remains off or at risk until the network interrogation has been completed. In modern more digital type substations this information is readily available, and the restoration time is greatly reduced thereby providing customers with the required service levels expected.

Therefore, replacement of these relays should be undertaken. If it were done as a stand-alone project, it would require staged outages within the substation, replacing of control cabling, installation of new panels and control equipment. The current control room on site is not adequate for such a replacement project and therefore a new control / relay room would also be necessary.

4.4. Conclusion for North Heidelberg ZSS

Jemena have proposed a redevelopment of the CS ZSS by installing standardised equipment to replace the ageing and at-risk primary and secondary assets. Their proposal includes the replacement of:

- Two 66 kV circuit breakers (Bus-ties)
- Three 22kV switchboards age Sprecher & Schuh switchboards (3 sections)

- An earth fault management system
- New protection and control equipment.

Based on the assessments made above in this Section 4 the replacement of the aged equipment is required before equipment failures start affecting the reliability of supply to customers.

The 66kV circuit breakers are bulk oil type and are the bus-tie breakers between the three NH power transformers. The breakers like those at CN and CS ZSS' are nearing their end of life and if a failure were to occur it would impact the substation transformers and likely cause a fire within the building. Any fire within the building is a serious risk to all the equipment as well as the workers.

The 22kV switchgear at the site comprises indoor minimum oil circuit breakers. This design has long been made obsolete as it poses safety risks to maintenance workers, has a higher risk of arc fault exposure with fire involved. New indoor 22kV arc-fault rated switchgear will offer greater safety and reliability for a smaller footprint. It would allow the site to be expanded to meet any future needs for additional feeders.

The protection relays are mostly old electro-mechanical relays and to replace them requires significant re-wiring of the protection and control schemes. This is best undertaken with the switchgear replacements as it can be wired to suit the new switchgear control system. The added benefit here will be that Jemena can utilise its SCADA and communications systems to manage any unplanned outage event remotely rather than having to have additional outage time due to the disadvantages with type of non-arc-fault rated equipment at site.

These replacements would enhance the safety and reliability of the site for the 16,000 customers and allow for the managing of the impact of increasing levels renewables on the network and allow expansion of the substation in the future.

The recommendation is for these assets to be replaced to ensure a safer and more reliable supply to customers. If they are not replaced, then it will have an increasing risk of primary plant failures that will cause widespread outages for the customers due to fires or total loss of the asset. The loss of any one 22kV circuit breaker could damage the bus-section that it is connected to. It is not necessarily supported by a manageable spare, and the control components are no longer available. Replacement switchboards can take around 18 months to manufacture from the time of placement of an order and so in that time the loads will need to be transferred. This would place additional load and so higher risk on the other primary plant or nearby substations.

5. CONCLUSION

K-BIK Power has assessed the assets that Jemena has identified for replacements at Coburg North and South and North Heidelberg zone substations. It has been concluded that the identified assets are aged and at risk of not only aged-related failures but also for network events that can trigger the age-related failure.

The assets proposed are largely no longer manufactured and components are not available for repairs.

The Coburg North Substation has a greater number of at-risk assets and as the substation is an antiquated design it also poses a safety risk for works maintaining the assets. Therefore, a complete substation replacement is the optimum outcome. If failures occur within the substation many other parts of the site are affected and replacements become challenging due to the exposed busbar style arrangements.

At Coburg South and North Heidelberg only specific at-risk assets are required to be replaced and these have been identified as oil filled circuit breakers and obsolete electro-mechanical relays. The highest risk in both sites is that a fire starts within the building due to an explosive failure. This risk is significant in that battling any fire in a substation requires the site to be isolated and with these being indoor sites it poses a greater risk to personnel.

Therefore, K-BIK Power recommends that all the Jemena replacement proposals be accepted for the reasons stated in this report.

End of Report