Jemena Electricity Networks (Vic) Ltd

Replace Zone Substation Heidelberg (HB) Transformers

2019 and 2020 Business Case

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Replace Zone Substation Heidelberg (HB) Transformers

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PREFACE

The intent of this business case is to substantiate the need and prudency of investment for both Jemena and its customers to replace transformers at Heidelberg Zone Substation. The business case outlines the strengths and weaknesses of a design option, in comparison with its alternatives, in a systematic and objective manner. The business case seeks endorsement and funding for the project from the appropriate Jemena stakeholders and approval from the relevant delegated financial authority.

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1. EXECUTIVE SUMMARY

Paper Summary

- The No.1 and No.3 66/11 kV 20/30 MVA transformers at Zone Substation Heidelberg (HB) are at a high risk of failure due to their poor condition;
- There are no spares available to minimise any possible outage duration;
- The 10% POE MD is predicted to exceed the N-1 rating in 2022 and beyond;
- To manage the risk of damage to key assets within HB Zone Substation due to condition-related failure this business case recommends replacing the existing No.1 66/11kV transformer with standard 20/33 MVA unit, installation of new No.2 66/11kV 20/33MVA transformer and scrapping the existing No.3 66/11kV transformer; and
- The project will be completed in 2022 at a cost of $9.606M (total project cost, real $2019).

Figure OV–1: Satellite View of HB Zone Substation

1.1 BUSINESS NEED

Heidelberg (**HB**) zone substation consists of two power transformers operating at 66/11kV and has seven 11kV feeders which supply 8,819 customers in the surrounding area. The No.1 and No.3 20/30MVA Wilson Transformer Company (**WTC**) power transformers are 54 years old.

Tests undertaken on the two transformers at HB zone substation and Condition Based Risk Modelling (CBRM) have identified significantly deteriorated assets which have triggered replacement prioritisation. The two transformers have deteriorated cellulose which is placing the transformers at an increased risk of failure. The cellulose condition is such that the transformers have reached the end of life and are being replaced due to their condition. Zone substation HB is islanded within the JEN network and has no transfer capability. The 10% POE MD is predicted to exceed the N-1 rating in 2022 and beyond. Therefore to maintain a reliable customer supply the two transformers must be replaced. As the JEN transformer fleet condition has been assessed, the planned and controlled replacement can be cost-effectively managed before catastrophic failure occurs.

Five current issues associated with the HB transformers have been identified:

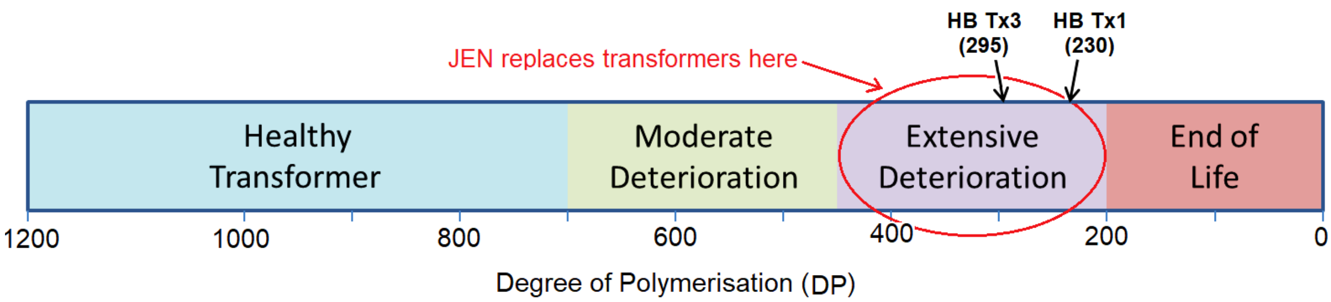
1. **Electrical tests (Polarisation & Depolarisation Current & Recovery Voltage Measurements) were conducted to estimate the average DP (Degree of Polymerisation) of the transformer paper insulation throughout the winding. The resultant DP for the No.1 and No.3 transformers was determined to be 230 & 295 respectively.**

   The mechanical condition of the transformer paper insulation will usually determine when a transformer is at the end of life as this degradation is not reversible and when the condition has reached a poor state, there is no corrective economic action to maintain the performance of the transformer. It is at this time that major refurbishment (if practicable and economic) or replacement of the transformer will be required. The determination of "end of life" is not absolute.

   Currently, the accepted method of life assessment for transformers is Degree of Polymerisation, which quantifies transformer paper condition and strength. A DP value of between 200 and 450 signifies that transformer insulation has experienced extensive deterioration and should be scheduled for replacement before failure occurs. At a DP value of 200, a transformer has reached nominal end of life and is at a higher risk of catastrophic failure.

   Polarisation and Depolarisation Current & Recovery Voltage Measurement (PDC/RVM) tests were conducted on the No.1 and No.3 transformers in 2011 and 2014, respectively. The resultant Degree of Polymerisation (DP) from these tests was 230 & 295 respectively. The PDC/RVM test results indicate that the paper strength of the No.1 and No.3 transformers at HB is extensively deteriorated, as shown in figure 2.3 below.

   Figure OV–2: Degree of Polymerisation Index



   The DP values of 230 and 295 from the two transformers at HB confirm the mechanical strength of the cellulose has deteriorated and is placing the transformers at an increased risk of failure. A close-in feeder fault will impose mechanical stress on the winding and may tear the paper and reduce the electrical insulation, resulting in a catastrophic transformer failure. This is a critical issue.

2. **Electrical tests (Polarisation & Depolarisation Current & Recovery Voltage Measurements) were conducted to derive an estimation of the water content of the No.1 and No.3 transformers insulating paper at 25°C to be 4.9% and 2.8% respectively.**

   A transformer's moisture content is a significant indicator of the transformer's condition and a major contributor to the rate of ageing of the paper insulation; water content of 2.2% in insulation is classed as moderately wet[1]. Moisture in insulation deteriorates the dielectric withstand strength, increases the rate of cellulose ageing and in the case of excessive temperatures generates gas bubbles. That is why moisture content in the insulation of power transformers should be monitored.

   The No.1 and No.3 transformers at HB have moisture contents of 4.9% and 2.8% respectively. This moisture level indicates that the paper insulation is extremely wet and the condition of the paper is severely deteriorated.

3. **The 1-2 66kV Bus Tie Circuit Breaker is from a family of circuit breakers with a history of mechanical failure and is no longer supported by a manufacturer, and therefore spare components are no longer available.**

   The 66kV Bus Tie Circuit Breaker represents a family of breakers with a history of mechanical failures and catastrophic bushing failures. This CB, Type LG4C is no longer supported by a manufacturer, and spare components are no longer available.

   If the 1-2 66kV Bus Tie CB failed, protection schemes would isolate both upstream circuit breakers effectively isolating the supply to the whole of zone substation HB. Zone substation HB is an island and customers would remain of supply until the 1-2 66kV CB was isolated. Ultimately the current condition of the CB is compromising customer reliability and security of supply. This is also a critical issue.

4. **Oil quality and dielectric strength in the No.3 transformer is rated as 'fair'.**

   This is not an issue that is driving the replacement of the transformers and oil condition will continue to be monitored and prioritised for oil regeneration. However, taking into consideration the overall condition of the transformer it is not considered prudent to regenerate the oil.

5. **The transformers have a history of oil leaks on the main tank and radiators.**

   This is not an issue that is driving the replacement of the transformers; however, it does require elevated levels of operating expenditure to manage. The oil leaks make the transformer's maintenance intensive. By replacing the No.1 and No.3 transformers at HB, the maintenance costs could be minimised and used to offset the cost to replace the transformers.

The following options to address these issues have been considered.

1. Do nothing
2. Increased maintenance & monitoring
3. Transformer refurbishment
4. Transformer re-wind
5. Transfer load
6. Replace transformers
7. Non-network Solutions

A comparison of the seven options listed above and the issues they address is shown in Table OV – 1-1.

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[1] Limits for water content are defined in the IEC 60422 standard.

Table 1-1: Options Analysis

Issues	Option 1 Do Nothing	Option 2 Increased Maint. & Monitoring	Option 3 Transformer Refurbishment	Option 4 Transformer Rewind	Option 5 Permanent Load Transfer	Option 6 Replace Transformers	Option 7 Non-network Solutions
Issue 1 Insulation Condition	○	○	○	●	●	●	○
Issue 2 Insulation Moisture	○	○	○	●	●	●	○
Issue 3 Transformer Oil Leaks	○	●	●	●	●	●	○
Issue 4 Safety Risk - Catastrophic Failure	○	◑	●	●	●	●	○
Issue 5 Customer Reliability	○	◑	●	●	●	●	○
Technically Viable	○	○	○	○	○	●	○

●	Fully addressed the issue
◕	Adequately addressed the issue
◑	Partially addressed the issue
○	Did not address the issue

1.2 RECOMMENDATION

Option 6 is recommended for a total cost of $9,606k (total project cost, real $2019) and involves replacing the existing No.1 WTC 66/11kV 20/30MVA transformer with a higher capacity 20/33MVA transformer, installing a new No.2 66/11kV 20/33MVA transformer and scrapping the existing No.3 transformer. The replacement transformers will have a higher thermal rating at minimal extra cost. This option is considered prudent, has a positive net present value and in addition to addressing all the condition issues identified in Section 2.2, it mitigates the risk to network performance and is the preferred option.

1.3 REGULATORY CONSIDERATIONS

The objective of the project is to determine the most appropriate strategy for the nominated assets to maintain customer supply reliability at HB given their current condition. This strategy must be consistent with other JEN strategies and plans and the project must comply with associated regulatory requirements including the National Electricity Rules (in particular clause 6.5.7), the Victorian Electricity Distribution Code and Environmental Protection regulation.

Six options will be explored in the Options Analysis in Section 3 of this document to identify the best possible option. The options will be benchmarked against the risk assessment from 0 to ensure the health, safety and reliability issues are addressed. Fundamentally risk, cost and value will be the primary drivers; however, the best value option, not the cheapest will be recommended.

1.4 FINANCIAL INFORMATION

1.4.1 FORECAST EXPENDITURE AND BUDGET SUMMARY

This business case proposes a total investment of $9,606k (total project cost, real $2019) and requires Managing Director's (Band B) approval under the SGSPAA DFA Manual, Annex 3.

This project is required to be commissioned by 2022 to avoid the risk of failure.

Table 1-2 presents a summary of the business case and budgeted value for this project, as well as the overhead allocations applied.

Table 1-2: Project Budget Information

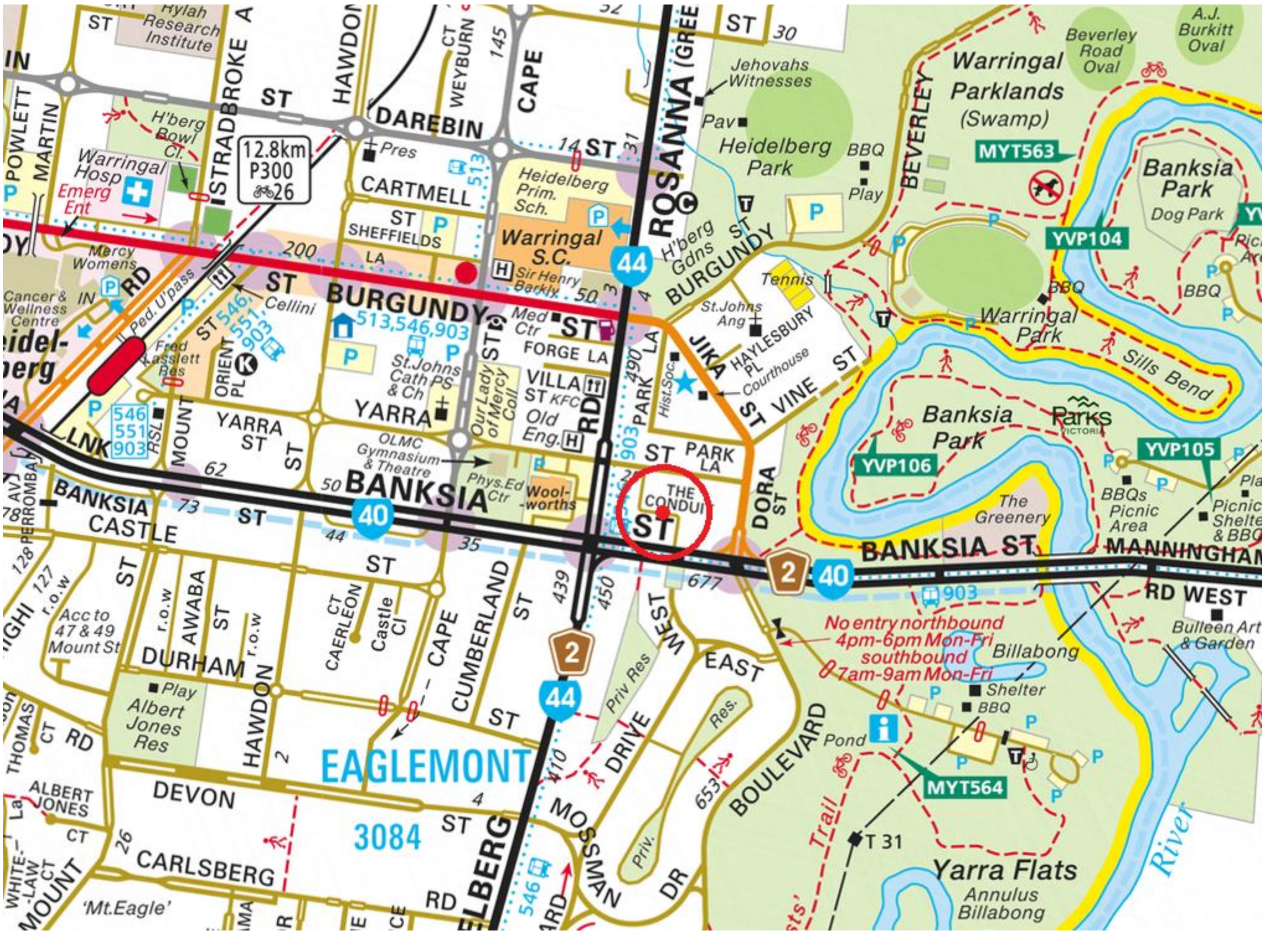
Business Case Spend	Total ($'000s, $2019)
CAPEX	7,410
Overhead Recovery	1,650
Total Business Case Value	**9,606**

2. BACKGROUND

The purpose of this document is to set out the business case for Heidelberg Zone Substation (HB) transformer replacement project. This business case examines the regulatory treatment in the JEN building block proposal and also confirms that the business case aligns with JEN's Electricity Primary Plant Asset Class Strategy. See Appendix A – ELE AM PL 0061 Electricity Primary Plant Asset Class Strategy.

HB was commissioned in 1966 and is located to the north-east of the Melbourne CBD on the corner of The Conduit and Yarra Street, Heidelberg (Melway Ref: 7 C3) as shown in Table 2-1. It supplies 8,819 customers in the Heidelberg and Ivanhoe areas. The customer split based on customer numbers is 91.23% residential, 8.70% commercial and 0.6% industrial. The split based on energy consumption is 68.10% residential, 25.20% commercial and 6.70% industrial.

Figure 2–1: Location of Zone Substation HB (Heidelberg)



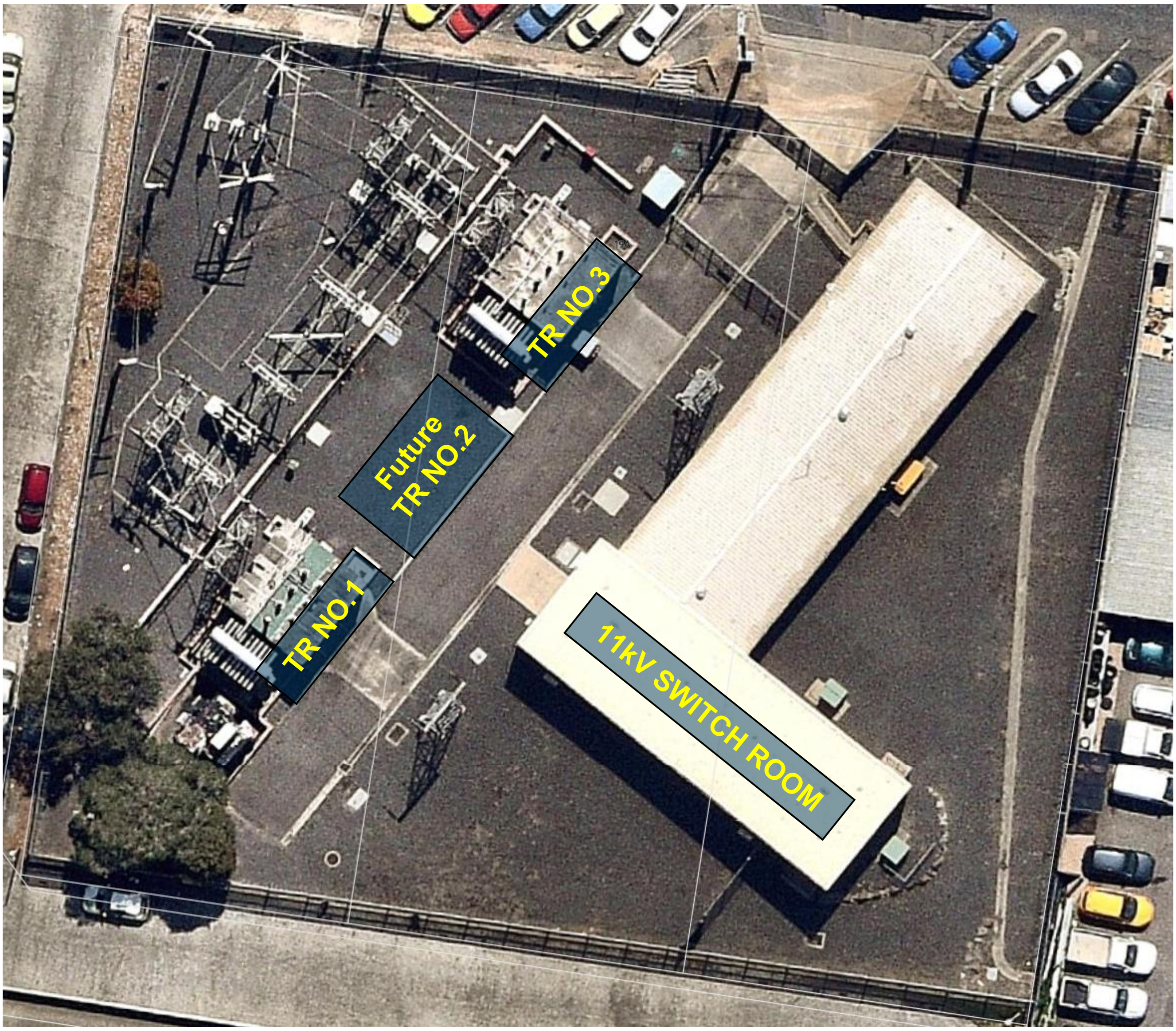
Zone Substation HB consists of the following major plant, as shown in Figure 2–2:

1. Two off 66/11kV 20/30MVA transformers (enclosed main tanks) supplied by 66kV sub-transmission lines from Templestowe Terminal Station (TSTS) and Citipower's Kew (Q) Zone Substation; and,

2. One-off 11kV ABB switchboard consisting of three 11kV buses supplying seven 22kV feeders.

Refer to Appendix B3 for the Single Line Diagram.

Figure 2–2: The existing general layout of Zone Substation HB



2.1 ASSET DETAILS

The power transformers installed at HB are described in Table 2-1 below. The transformer enclosures and 66kV bus are shown in Figure 2–3.

Table 2-1: Zone Substation HB Power Transformer Details

Transformer	Make	Voltage	Capacity	SECV Spec No.	Year of Manufacture
Transformer No.1	Wilson Elec. Co	66/11kV	20/30MVA	63-64/246	1965
Transformer No.3	Wilson Elec. Co	66/11kV	20/30MVA	63-64/246	1965

Figure 2–3: HB Transformer Enclosure, Radiator and 66kV Bus

The annual Maximum Demand (MD) at HB, currently 28.8MVA, occurs in summer (1 Dec of the previous year to 31 Mar). The N-1 station cyclic rating is 29.2MVA in summer. The MD is predicted to exceed the N-1 rating in 2022 and beyond. The actual and estimated maximum loading in the period 2017 to 2025 is shown in Table 2-2[2].

Table 2-2: HB Station Loading

Station Loading (MVA)	Actual		Estimated						
	2017	2018	2019	2020	2021	2022	2023	2024	2025
10% POE MD	25.4	27.0	28.8	28.8	29.0	29.5	29.7	29.7	29.9

There have been twenty-one recorded defects on the HB transformers since 2008 and all have been relatively minor, resulting in minor levels of operating expenditure. The defects are shown in Table 2-3 below.

[2] The forecast loading estimate is derived from the Distribution Annual Planning Report 2018, which can be accessed here.

Table 2-3: HB Transformers Defect History

Date	Asset	Defect	Remedy
25 May 2010	No.1 Transformer	Tap changer out of step	Repair auxiliary switch
19 Aug 2010	No.3 Transformer	Corona activity on the bushing	Noted
16 Dec 2010	No.1 Transformer	Leaking oil	Tighten bolts and clean
22 Jun 2012	No.3 Transformer	Tap changer out of step	Repair auxiliary switch
27 Apr 2012	No.1 Transformer	Damaged Roof Slabs	Civil Contractor to Investigate
22 Jun 2012	No.3 Transformer	Transformer Out of Step	Investigate and Repair
18 Dec 2012	No.3 Transformer	Dislodged B Ph Bushings Cover	Investigate and Repair
17 Feb 2014	No.1 Transformer	Leaking Oil	Tighten Gaskets and Bolts
06 May 2014	No.3 Transformer	Transformer Out of Step	Investigate and Repair
01 Jul 2014	No.3 Transformer	Rust at Bottom of Main Tank	Treat Rust
12 Aug 2014	No.3 Transformer	Low Oil	Top Up Oil
11 Nov 2014	No.3 Transformer	Transformer Out of Step	Investigate and Repair
05 Jan 2015	No.1 Transformer	Leaking Oil	Tighten Gaskets and Bolts
18 Jun 2015	No.1 Transformer	Damaged Roof Slabs	Paint No-Go-Zone on Roof
01 Jul 2015	No.1 Transformer	Defective Winding Temp Gauge	Investigate and Repair
20 Nov 2015	No.3 Transformer	Leaking Oil	Tighten Gaskets and Bolts
20 Nov 2015	No.1 Transformer	Leaking Oil	Tighten Gaskets and Bolts
11 Dec 2015	No.1 Transformer	Low Oil	Top Up Oil
04 Mar 2016	No.1 Transformer	Leaking Oil	Tighten Gaskets and Bolts
05 Jun 2016	No.1 Transformer	Defective OLTC Motor	Investigate and Repair
14 Oct 2016	No.1 Transformer	Leaking Oil	Tighten Gaskets and Bolts
10 Apr 2017	No.1 Transformer	Transformer Out of Step	Investigate and Repair
10 Apr 2017	No.3 Transformer	Transformer Out of Step	Investigate and Repair
01 Mar 2018	No.1 Transformer	Dirty Sight Glass	Clean Sight Glass and Top Up Oil
10 Aug 2018	No.1 Transformer	Low Oil	Top Up Oil

Figure 2–4: HB No.1 Power Transformer Radiator Oil Leaks

There have been two recorded defects on HB 66kV bus tie circuit breaker since 2008. The defects are shown in Table 2-4.

Table 2-4: HB 66kV Bus Tie CB Defect History

Date	Asset	Defect	Remedy
2 Sep 2010	66kV Bus Tie CB	Failed mechanical integrity	Repair mechanical linkage
9 Oct 2012	66kV Bus Tie CB	Failed mechanical integrity	Replace hold-on catch pin

There have been four recorded defects on the HB 66kV bus since 2008. The defects are shown in Table 2-5.

Table 2-5: HB 66kV Bus Defect History

Date	Asset	Defect	Remedy
22 Jun 2012	No.2 66kV Bus	Corona Activity	Noted
08 Jan 2016	No.3 Transformer 66kV Disconnect Switch	66kV Disconnect Failure	B Ph flicker came off when operating - Investigated and repaired
06 Oct 2016	No.3 66kV bus VT	Leaking Oil	Investigate and repair
04 Jul 2018	1-2 66kV bus tie CB No.2 bus side isolator	Thermo Vision hot spot on the 1-2 66kV bus tie CB, No.2 bus side isolator	Investigate and repair

2.2 ASSET RISK ANALYSIS

2.2.1 ASSET CONDITION

The transformers at Zone Substation HB undergo a condition-based monitoring regime which is detailed in the Zone Substation Primary Plant Asset Class Strategy (ELE AM PL 0061). A summary of the Condition Monitoring Index for HB transformers is shown in Table 2-6.

Table 2-6: HB Transformer Condition Monitoring Index

Legend	Good	Test, Evaluate & Monitor	Initiate Life Extension Program or Replace

Test	Parameter	Transformer No.1	Transformer No.3
PDC/RVM	Paper DP	230	295
PDC/RVM	Moisture in Paper	4.9%	2.8%
PDC/RVM	Oil Quality	Fair	Good
Oil Test	Moisture in Oil	21	21
Oil Test	Acidity in Oil	0.02	0.02
Oil Test	DGA	✓	✓
Oil Test	Dielectric	45	31
Oil Test	Interfacial Tension	29	31
Oil Test	Copper Sulphide	No	No

Five current issues associated with the HB transformers have been identified and are discussed below.

1. **Electrical tests, PDC/RVM (Polarisation & Depolarisation Current & Recovery Voltage Measurements) were conducted to estimate the average DP (Degree of Polymerisation) of the transformer paper**

insulation throughout the winding. The resultant DP for the No.1 and No.3 transformers was determined to be 230 and 295 respectively.

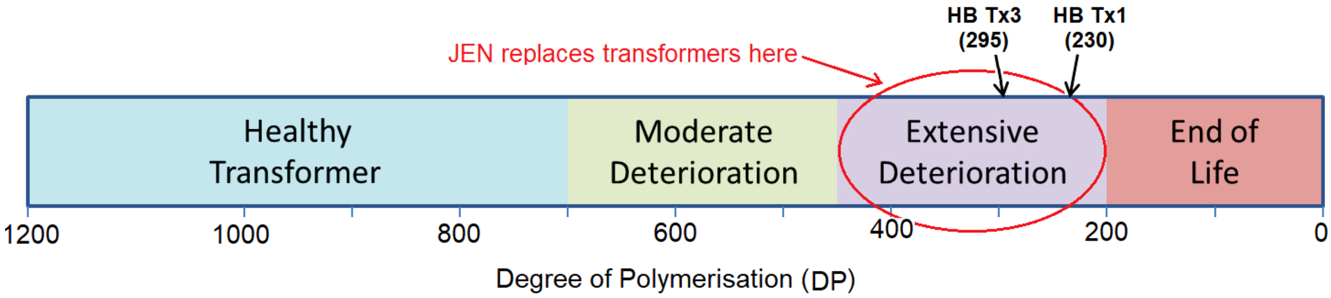
The mechanical condition of the transformer paper insulation will usually determine when a transformer is at the end of life as this degradation is not reversible and when the condition has reached a poor state, there is no corrective economic action to maintain the performance of the transformer. It is at this time that major refurbishment (if practicable and economic) or replacement of the transformer will be required. The determination of “end of life” is not absolute.

Currently, the accepted method of life assessment for transformers is Degree of Polymerisation, which quantifies transformer paper condition and strength. While the determination of “end of life” is not absolute, a DP value of between 200 and 450 signifies that transformer insulation has experienced extensive deterioration and should be scheduled for replacement before failure occurs. At a DP value of 200 a transformer has reached end of life and is at a higher risk of catastrophic failure.

PDC/RVM tests were conducted on the No.1 and No.3 transformers at HB in 2011 and 2014 respectively. The resultant Degree of Polymerisation (DP) from these tests was 230 & 295 respectively

The PDC/RVM test results indicate that the paper strength of the No.1 and 3 transformers at HB is extensively deteriorated, as shown in Figure 2–5 below.

Figure 2–5: Degree of Polymerisation Index



PDC is the measurement of polarisation and depolarisation currents in the range of nano-Amperes over sufficient periods, normally 5,000 to 10,000 seconds for each current measurement. The duration and the magnitude of the polarisation and depolarisation currents reveal the condition of the paper insulation. The applied polarisation voltage is normally in a range of 200~1000 volts DC. RVM is a dielectric response measurement method that measures the values of return voltage after polarising and depolarising the insulation. The return voltage is caused by the charge accumulated (trapped) at the oil-paper interface during the polarisation (charging) period. And it (the return voltage) is a result of the interfacial polarisation and the subsequent depolarisation. The PDC/RVM test results are shown in Appendix B.

The DP values of 230 and 295 derived from the PDC/RVM testing of the two transformers at HB confirm the mechanical strength of the insulation has deteriorated and is placing the transformers at an increased risk of failure. A close-in feeder fault will impose mechanical stress on the winding and may tear the paper and reduce the electrical insulation, resulting in a catastrophic transformer failure. This is the critical issue.

It should be noted that both transformers are 54 years old and so the poor condition of the paper insulation is not surprising. The replacement plan aligns with the Electricity Primary Plant Asset Class Strategy (ELE AM PL 0061) which states “although some transformers have continued to operate satisfactorily for over 50 years, a 50-year-old transformer is approaching the end of its practical life.” Furthermore, the strategy also states that “achieving at least a fifty-year service life will maximise the economic life of the asset and this will result in lowest costs to the customer.”

2. **The 66kV Bus Tie Circuit Breaker is from a family of breakers with a history of mechanical failures. The CB is no longer supported by a manufacturer and spare components are no longer available.**

   JEN presently has 9 LG4C 66kV circuit breakers manufactured from 1964 in service with one installed at HB. Refer to Appendix A for the Electricity Primary Plant Asset Class Strategy.

   There were two catastrophic failures of this type of CB, one at Brooklyn and one at West Melbourne Terminal Stations in the late 1990's and early 2000's. Both failures were related to the 66kV bushings.

   These CB's are no longer supported by the manufacturer and consequently, spare components such as 66kV bushings, turbulators, solenoids and mechanism components are no longer available. JEN currently has very limited spares (i.e. trip and close coils); however do not have any spare 66kV bushings.

   The failure of a 66kV bushing poses a risk to the safety of field crews. Continued maintenance and testing will not prevent the failure of a bushing. The cost of engineering new replacement bushings, procurement and installation would be comparable to installing a new CB. Replacement of the bushings alone does not address the mechanical wear and lack of spare parts.

   There has been a defect identified in the mechanism of these CB's involving the retaining of a shaft by a washer that is peened on the end of the shaft. This indicates component failure due to mechanical wear and has resulted in damage to the mechanism. A new component was designed and manufactured as original spare parts are not available. An inspection of all of these breakers has been undertaken and a plant defect notice issued. This shows that the CB's are entering a wear-out phase and due to a lack of spare parts, components are being re-engineered independently outside of the original equipment manufacturer specification which takes time and is costly. This development of a single pin costs over $5,000 to develop and the material cost was about $5.00.

   If the 1-2 66kV Bus Tie CB were to fail both sub-transmission lines supplying zone substation HB would be lost isolating supply to HB. Zone substation HB is an island and customers would remain of supply until the 1-2 66kV CB was isolated. Ultimately the current condition of the CB is compromising customer reliability and security of supply.

3. **Electrical tests (Polarisation & Depolarisation Current & Recovery Voltage Measurements) were conducted to derive an estimation of the water content of the No.1 and No.3 transformers insulating paper at 25°C to be 4.9% and 2.8% respectively.**

   A transformer's moisture content is a significant indicator of the transformer's condition and a major contributor to the rate of ageing of the paper insulation. Water content of 2.2% in insulation is classed as moderately wet[3]. Moisture in insulation deteriorates the dielectric withstand strength, increases the rate of cellulose ageing, and in the case of excessive temperatures generates gas bubbles. That is why moisture content in the insulation of power transformers should be monitored.

   The No.1 and No.3 transformers at HB have moisture contents of 4.9% and 2.8% respectively. This indicates that the paper insulation is extremely wet and the condition of the paper is severely deteriorated. This is also a critical issue.

   To remove the moisture the transformers would have to be de-tanked and dried out, core tightened, gaskets changed and re-commissioned. This process is labour intensive and expensive. At the end of the process, the transformer would still be >50 years old and have poor mechanical strength due to the degraded kraft paper used to insulate the windings and associated components.

[3] Limits for water content are defined in the IEC 60422 standard.

When a transformer is out of service, operating the remaining aged and deteriorated transformer at full capacity with low DP values and high moisture in paper is not ideal because it presents a higher probability of failure. Operating the transformers at high temperatures will increase the likely hood of a turn-to-turn fault occurring within the windings. This will have a direct effect on network performance and strengthens the case for the AER to approve the replacement of the two power transformers.

4. Oil quality and dielectric strength in No.3 transformer are only fair.

This is not an issue that is driving the replacement of the transformer and oil condition will continue to be monitored and prioritised for oil regeneration. However, taking into consideration the overall condition of the transformer it is not considered prudent to regenerate the oil.

5. The transformers have a history of oil leaks on the main tank and radiators.

This is not an issue that is driving the replacement of the transformers; however, it does require elevated levels of operating expenditure to manage. The oil leaks make the transformer's maintenance intensive. These issues are not driving the replacement of the transformers however they require elevated levels of maintenance to manage. By replacing the No.2 transformer and making the No.1 transformer a hot standby, the maintenance costs could be minimised and used to offset the cost to replace the transformers.

The following options to address these issues have been considered.

1. Do nothing
2. Increased maintenance & monitoring
3. Transformer refurbishment
4. Transformer re-wind
5. Transfer load
6. Replace the transformers
7. Non-network Solutions

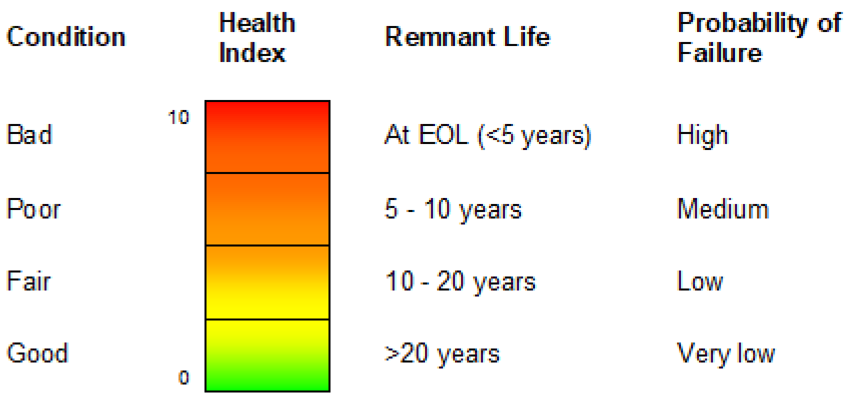
The option of non-network solutions (e.g. demand management and / or embedded generation) is not an alternative for removing the asset condition risk at HB zone substation.

2.2.2 CONDITION BASED RISK MANAGEMENT MODELLING RESULTS

Condition Based Risk Management (**CBRM**) is a technique for power transformer assets used to assist in the development of asset investment plans using existing asset data and other relevant information. A description of the model and the results for zone substation related assets is in document 'Jemena CBRM Report – Zone Substation Assets'.

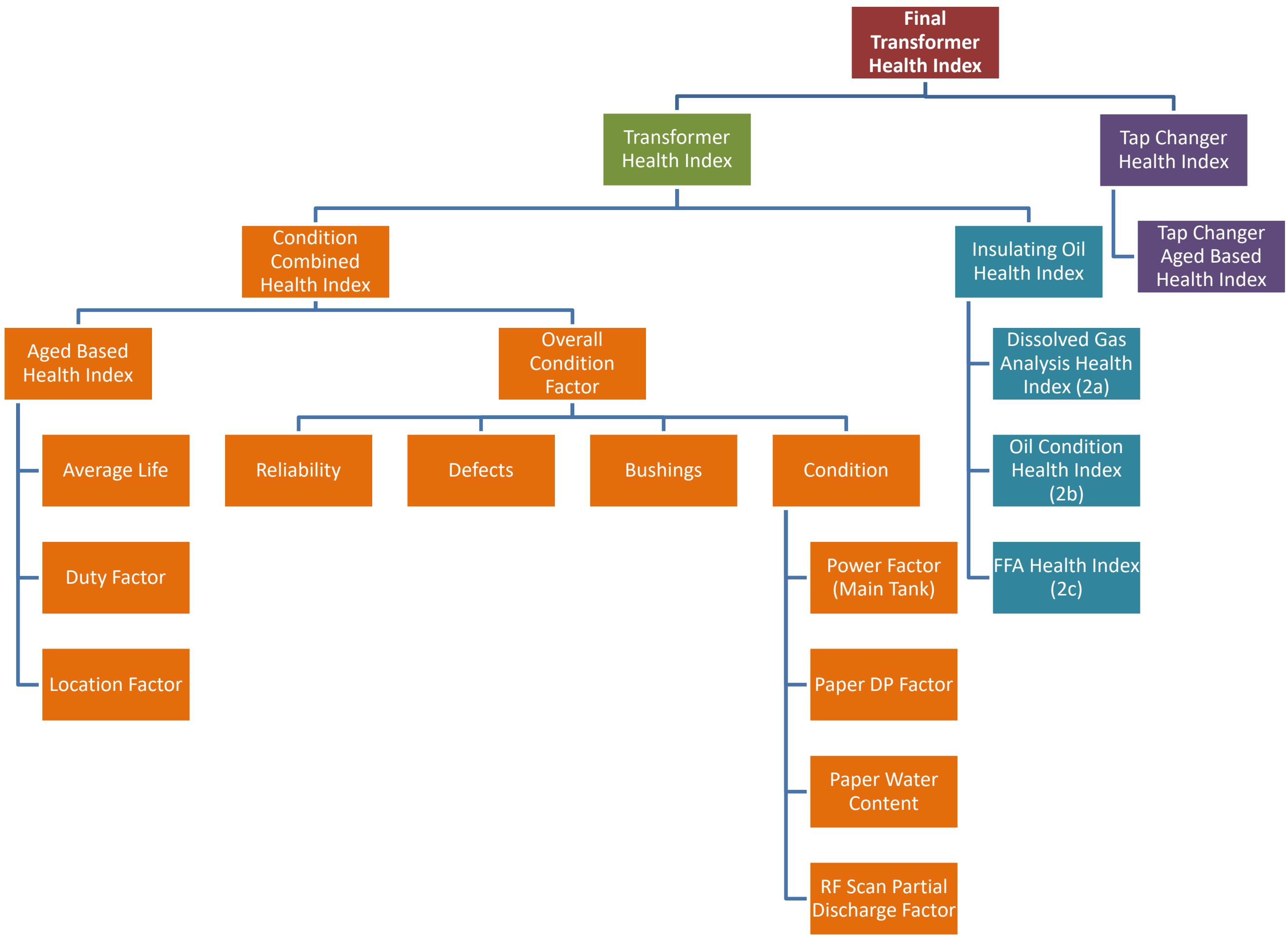
CBRM uses a Health Index for each asset based on a scale from 0 to 10. Values of health index above seven represent serious deterioration. The CBRM Health Index is a numeric representation of the condition of each asset. Essentially, the health index of an asset is a means of combining information that relates to its age, environment and duty, as well as specific condition and performance information to give a comparable measure of condition for individual assets in terms of proximity to end of life (EOL) and the probability of failure. The concept is illustrated schematically below in Figure 2–6.

Figure 2–6: CBRM Health Index



The inputs used for transformer assessment modelling are shown in Figure 2–7.

Figure 2–7: Power Transformer Health Formulation



The CBRM modelling indicates that the HB Zone Substation No.1 and No.3 transformers have a current health index result of **7.00** and **7.01** respectively. This indicates that both transformers are in poor condition and the probability of failure is high. These modelling results support the condition findings discussed above.

In Year 5 (2025), these results become **8.62** and **8.62** respectively, the CBRM result of both transformers is at the extreme end of the scale. Consequently, the likelihood of failure increases as the transformers age and became less reliable. As a result network performance is compromised placing customers supply at risk

2.2.3 FAILURE MODES

The cause of transformer failure can include:

- Insulation failure;
- Winding failure;
- Overloading;
- Oil degradation;
- Lightning and other line surges;
- Inadequate maintenance; and
- Design/manufacturing errors.

A transformer can fail due to thermal, electrical or mechanical factors; however while a typical failure mode is difficult to predict, most failures result from a breakdown of the transformer's insulation system.

A likely mode of failure will be inter-turn winding insulation failure as a result of the mechanical forces created by a fault within or downstream of the transformer. The insulation paper will not have the mechanical strength to maintain the required insulation during winding deformation.

In order to develop a risk cost associated with a permanent failure of the No.1 and No.3 power transformers at Zone Substation HB, a likelihood of failure and associated consequence of failure has been developed.

2.2.4 LIKELIHOOD OF FAILURE

The probability of a permanent transformer failure at Zone Substation HB has been modelled using Perks' formula. The formula is purely an age-based model which compares transformer age to the likelihood of failure. It is used as a benchmarking tool, where failures based on aging can be used to calculate the cost of risk. Further explanation of the model is outlined in 0.

The model has predicted that the current probability of a single power transformer catastrophic failure to be 48% per annum at Zone Substation HB. This is determined from the Transformer Failure Rate Function. The model's curve indicates that the transformers at Zone Substation HB are in the region where failure rates are increasing exponentially. The model indicates by 2022 the failure rate probability will increase to 70% per annum. Due to the load at risk and safety issues associated with a catastrophic failure, this is an unacceptable level of risk.

The correlation between calendar age and insulation deterioration is subject to some uncertainty. The Perks Model is a statistical model and does not take into account other conditions such as manufacturing differences and loading history; it is a second-order check of the business case. Ultimately condition monitoring tests (i.e. DP) are used to justify the replacement of the transformers.

In this business case, it is assumed that the failure rate of one transformer is independent of the others. There is, however, a possibility that the two transformers could fail simultaneously as they are all connected in parallel; however, this scenario has not been modelled. If multiple transformer failures were to occur the business case for replacement would be all the more supported.

2.2.5 CONSEQUENCE OF FAILURE

The worst case consequence of failure would include a transformer fire. The consequence of a transformer fire can be catastrophic as shown in the following three examples:

- On 14 October 2012, a transformer at the Hume power station (commissioned 1958) faulted and caught fire. Delays in isolating the station resulted in the transformer burning for two hours before crews could begin to extinguish the fire. Five hundred people were evacuated from the surrounding area due to smoke conditions. The fire was not extinguished until the next morning.
- On 26 November 2004, the DVY No.3 Transformer in Dandenong (commissioned in 1999) exploded and caught fire. Porcelain debris was found up to 50 meters away from the transformer in the 66kV switchyard, in the neighbouring tile shop and car park. The main transformer and its associated equipment including the transformer cables, control cables, civil works, 66kV and 22kV neutral isolators were completely destroyed. There was also damage to the adjacent No.2 mobile transformer affecting the transformer cables, control cubicle, tires and electronic equipment.
- On 10 September 1989, the No.2 and 3 transformers at the Union Road substation (commissioned 1958) in Albury exploded and caught fire and as a result were completely destroyed. The generation of heat was such that the fire in the No.3 transformer was not extinguished until 12 hours after the fault.

From a business and asset management perspective, it is prudent that the condition of assets installed on the network is maintained to ensure HV outages are minimised and OH&S regulations are met. Addressing the elevated risk of transformer failure aligns with the current JEN strategy and plans.

A risk assessment has highlighted five prominent risk as per section 2.2 above. By implementing this project these risks are mitigated to an acceptable level/rating, illustrating the need for the business to undertake the project.

The direct costs associated with such catastrophic failures have been identified as:

- Network Performance (STPIS);
- Operating Expenditure (OPEX); and
- Capital Expenditure (CAPEX).

For a transformer failure at Zone Substation HB, each of these costs are further explained and developed below.

Network Performance

Previous experience (DVY and Albury) has shown that catastrophic transformer failure resulting in fire and smoke can require the zone substation to be totally off supply whilst the fire is extinguished and this may take up to 12 hours. Once the fire is extinguished it can take another six hours of repair work to adjacent assets before supply is restored.

For modelling purposes, it is assumed supply could be restored in 18 hours[4].

The network performance impact (STPIS) associated with this scenario based on a SAIFI cost of $0.95 per minute off supply and a SAIDI cost of $55.40 per customer off supply, would be:

18(hrs) x 60(mins) x $0.95/min + 8,900 (Customers supplied from HB) x $55.40/Cust = $494k (real 2019).

[4] Failure of only one transformer.

Note that the restoration time has little impact on the figure, as even if the outage time was reduced to six hours, the figure would only be reduced by $1k.

CAPEX

The capital expenditure associated with a single permanent failure is estimated to be $2.41M (real 2019) as per the Electricity Primary Asset Class Strategy (ELE AM PL 0061). This represents the equipment replacement cost (including disposal of the replaced transformer). This capital expenditure figure is based on historical replacement costs.

OPEX

The operating expenditure associated with a single permanent failure is estimated to be $0.591M (real 2019). This represents the operating costs associated with the forced outage resulting from the transformer failure. This cost has been derived using the historical data from the DVY (Dandenong Valley) transformer failure in 2004. It includes activities such as network operations to restore supply, environmental remediation after an oil spill, clean-up of fire damage, structural damage repairs (including repairs to the adjacent transformer) and other safety-related costs.

Table 2-7: DVY Transformer clean-up cost

DVY Clean-Up Costs	
Activity	**Cost**
Demolition work by Wilsons Transformers	$20,099
Damage to adjacent plant	$19,568
22kV cable replacement	$20,711
66kV isolator replacement	$24,570
Surge arrestor replacement	$5,844
NPS charges	$197,145
Design & drafting	$48,599
SCADA	$8,986
Miscellaneous	$45,213
2004 Costs	**$390,735**
years (2004-2019)	15
Inflation (from Reserve Bank)	2.8%
2019 (real 2019 $)	**$591,260**

Total Cost of Risk

The worst-case cost of risk for a transformer failure has been determined using the results outlined in Table 2-7. This represents the annual potential impact.

Cost of Risk p.a. = ($ Network Performance + $ CAPEX + $ OPEX) x Probability

= ($494k + $2,411k + $591k) x 29.2%

= $1021k p.a. (real 2019)

The worst case cost of risk for a transformer failure has also been determined using the results outlined in Table 2-7 in conjunction with a failure rate for 2024 into the future. This represents the annual potential impact.

Cost of Risk p.a. = ($ Network Performance + $ CAPEX + $ OPEX) x Probability

= ($494k + $2,411k + $591k) x 44.3%

= $1,549k p.a. (real 2019)

Note: The probabilities in the calculations above are derived from the second graph in 0.

2.3 SMART SUBSTATION INITIATIVES

Keeping pace with the changing landscape of the electricity grid and the advent of the smart substation, the following technologies will be implemented from a primary plant perspective:

- Transformer fibre optic winding temperature sensors
- Transformer online bushing PD monitoring
- Transformer online temperature & moisture monitoring
- Online monitored zone substation video surveillance system & motion-activated LED lighting

The transformer that will be supplied for this project will have the fibre optic winding temperature sensors embedded. This will allow an accurate determination of the winding hotspot to enable JEN to operate the transformers more effectively, especially in times of extreme demand.

Transformer bushing PD monitoring will be implemented for both the new transformers at HB. This will be an innovative pilot project on the JEN network as the incremental cost to avail this technology is rather small as the field resources would already be mobilised on-site allowing us to gain synergies that would result in cost saving.

Transformer online temperature & moisture monitoring by Aurtra will also be implemented for both the new transformers. This will provide us with valuable information about the transformers as their loading varies. A full-scale online DGA monitoring system is not recommended for HB as it is more valuable for assets approaching the end of life.

The cost to implement the above mentioned technologies would be far more cheaper if done as part of this project. Retrofitting the above at a later stage would cost more.

JEN has experienced recurring unauthorised entries and theft of valuable power tools, HV test sets and materials[5] during major construction works in zone subs. It is recommended to install security cameras with back to base monitoring to help prevent theft of valuable tools and equipment. The security cameras shall be left on-site post commissioning to monitor and deter unauthorised entries. Lighting in the 66kV switchyard will be upgraded to motion-activated LED lights to act as a deterrent for intruders.

The 11kV switchboard was upgraded in 2011 along with secondary assets; IEC61850 is therefore not being considered for this project.

5 In 2017 at AW zone substation a HV test set valued at $100,000 was stolen

2.4 PROJECT OBJECTIVES AND ASSESSMENT CRITERIA

2.4.1 OBJECTIVE

The objective of the project is to determine the most appropriate strategy for the transformer assets at Zone Substation HB given their current condition. This strategy must be consistent with other JEN Strategies and plans and must comply with associated regulatory requirements including the National Electricity Rules (in particular clause 6.5.7), the Victorian Electricity Distribution Code and Environmental Protection regulation.

Seven options will be explored in the Options Analysis in Section 3 to identify the best possible option. The options will be benchmarked against the risk assessment from Appendix to ensure the health, safety and reliability issues are addressed. Fundamentally risk, cost and value will be the primary drivers however the best value option, not the cheapest will be recommended.

2.4.2 REGULATORY REQUIREMENTS

The Section of the National Electricity Rules (Version 124) relevant to this project is:

Section 6.5.7 – Forecast Capital Expenditure

a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

The sections of the Electricity Distribution Code (Version 9A – August 2018) relevant to this project are:

Section 3.1 – Good Asset Management

*A **distributor** must use best endeavours to:*

a) *assess and record the nature, location, condition and performance of its **distribution system** assets;*

b) *develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its **distribution system** assets and plans for the establishment and **augmentation** of **transmission connections**:*

- *to comply with the laws and other performance obligations which apply to the provision of **distribution** services including those contained in this Code;*
- *to minimise the risks associated with the failure or reduced performance of assets; and*
- *in a way which minimises costs to **customers** taking into account **distribution losses**; and*

c) *develop, test or simulate and implement contingency plans (including where relevant plans to strengthen the security of supply) to deal with events which have a low probability of occurring, but are realistic and would have a substantial impact on **customers**.*

Section 5.2 - Reliability of Supply

*A **distributor** must use best endeavours to meet targets required by the **Price Determination** and targets published under clause 5.1 and otherwise meet reasonable **customer** expectations of **reliability of supply**.*

The section of the Environment Protection Act 1970 (No.8056 of 1970, Part **III** – Environment Protection) relevant to this project is:

Section 27A – Offences relating to industrial waste

(1) A person who—

(a) contravenes any rules or requirements relating to industrial waste specified in a waste management policy; or

(b) contravenes any regulations relating to industrial waste; or

(c) causes or permits an environmental hazard—

is guilty of an indictable offence.

Penalty: 2400 penalty units plus, in the case of a continuing offence, a daily penalty of 1200 penalty units for each day the offence continues after conviction or after service by the Authority on the accused of notice of contravention of this subsection (whichever is the earlier).

Note: The values for the 2018–19 financial year were gazetted (Victoria Government Gazette Number S 145; PDF 301KB) on 29 March 2018 and are as follows: One fee unit = $14.45, One penalty unit = $161.19.

JEN must also comply with the Environment Protection Act (1993) as well as the updated bunding guidelines (EPA bunding guidelines 347.1) released by the EPA in 2015, as it seeks to reduce the risk of failing equipment causing significant environmental impact.

In respect to power transformers, JEN seeks to comply with these regulatory obligations through the development and implementation of its Zone Substation Primary Plant Asset Class Strategy. JEN must also comply with the State Environmental Protection Regulation (Control of Noise from Commerce, Industry and Trade No. N-1 (SEPP N-1).

2.4.3 ASSESSMENT CRITERIA

The assessment criteria by which projects will be assessed against and the extent to which each of the identified options addresses the three transformer condition issues are described in Section 2.2.

2.5 CONSISTENCY WITH JEMENA STRATEGY AND PLANS

JEN's focus is to improve its competitiveness and adaptability in the following ways:

1. Efficiently and safely deliver affordable and reliable energy;
2. Make the customer experience easier and more valuable through digital and performance improvements; and
3. Modernise the grid to prepare for a connected future.

JEN seeks to ensure that the whole of lifecycle costs are minimised. This business case has considered and is consistent with this requirement, including that the selected option is consistent with the long term vision for the network as set out in the NAMP and annual planning reports.

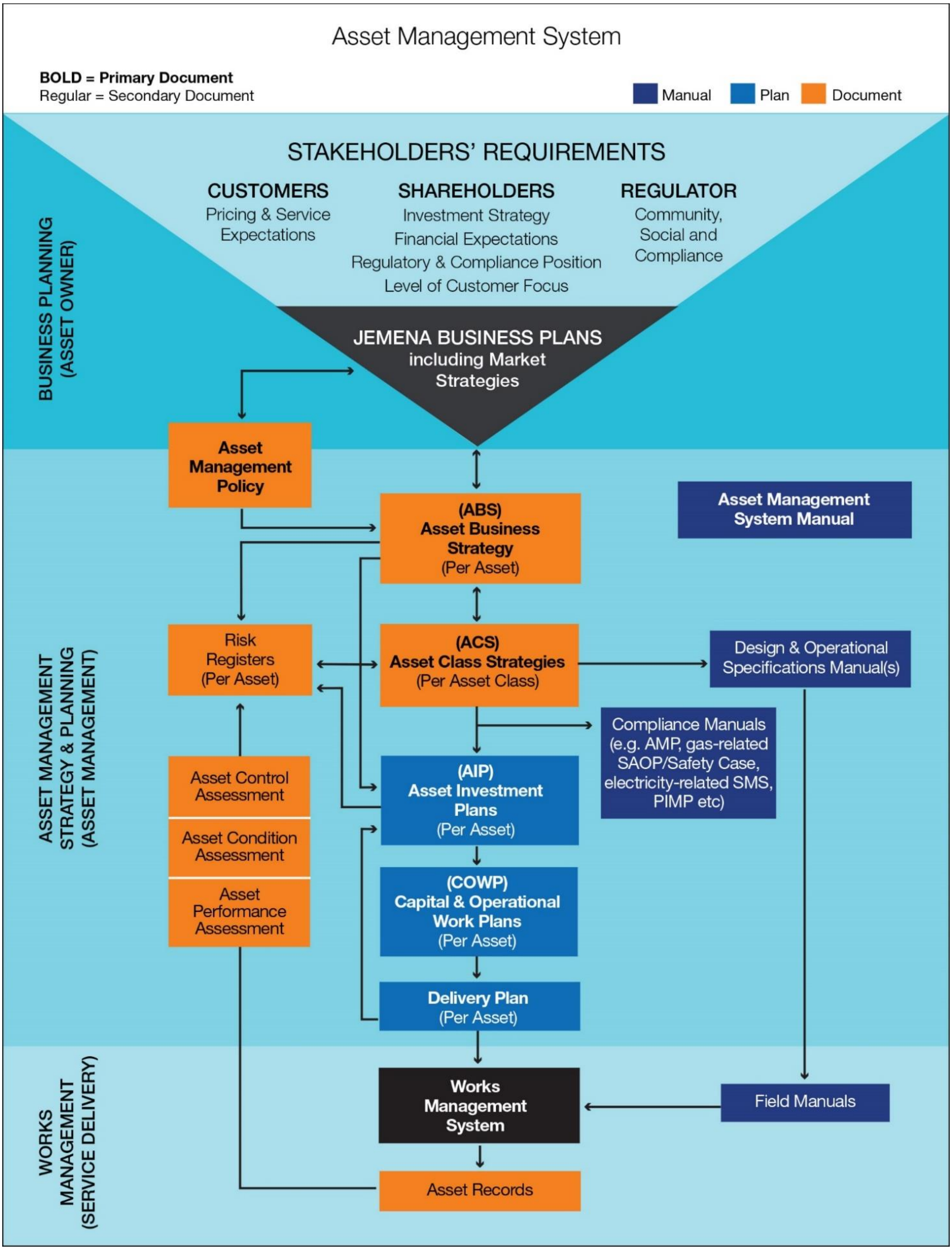
JEN must comply with regulatory obligations; these are incorporated into the development and implementation of its Zone Substation Primary Plant Asset Class Strategy. The Asset Class Strategy creates a line of sight between the JEN Business Plan and the Asset Management Plan.

This proposal aligns with Asset Management Strategies, Plans & Policies as it will contribute to ensuring a safe place of work for JEN employees and contractors. By completing this project, JEN can reduce its exposure to the possibility of litigation by authorities due to an injury or environmental incident.

Figure 2–8 outlines the Jemena asset management system and where the Asset Management Plan (AMP) is positioned within it. The AMP covers the creation, maintenance and disposal of assets including investment planned to augment network capacity to meet increasing demand and to replace degraded assets to maintain the reliability of supply to meet Jemena Business Plan requirements.

This strategic framework facilitates the planning and identification of business needs that require network investment documented via business cases.

Figure 2–8: The Jemena Asset Management System



3. CREDIBLE OPTIONS

This section discusses how credible options are identified and developed. The credible options are considered for their commercial and technical feasibility, abilities to address the identified needs, deliverability, economic and financial benefits, as well as legal and regulatory implications.

3.1 IDENTIFYING CREDIBLE OPTIONS

The following feasible options could be used to address the business need, problem or opportunity.

1. Do Nothing
2. Increased Maintenance and Monitoring
3. Transformer Refurbishment
4. Transformer Rewind
5. Transfer Load
6. Replace the Transformer
7. Non-network Solutions

3.2 DEVELOPING CREDIBLE OPTIONS COSTS & BENEFITS

The credible options are discussed in the following sub-sections. Note that all expected option costs include overheads.

The option of a non-network solution (e.g. demand management and/or embedded generation) is not an alternative for removing the asset condition risk at the zone substation. The asset condition risk would remain until the assets are either replaced or decommissioned.

A comparison of the seven options listed above and the issues they address is shown in Table 3-1.

Table 3-1: Options Analysis

Issues	Option 1 Do Nothing	Option 2 Increased Maint. & Monitoring	Option 3 Transformer Refurbishment	Option 4 Transformer Rewind	Option 5 Permanent Load Transfer	Option 6 Replace Transformers	Option 7 Non-network Solutions
Issue 1 Insulation Condition	○	○	○	●	●	●	○
Issue 2 Insulation Moisture	○	○	○	●	●	●	○
Issue 3 Transformer Oil Leaks	○	●	●	●	●	●	○
Issue 4 Safety Risk - Catastrophic Failure	○	◑	●	●	●	●	○
Issue 5 Customer Reliability	○	◑	●	●	●	●	○
Technically Viable	○	○	○	○	○	●	○

◕	Adequately addressed the issue
◑	Partially addressed the issue
○	Did not address the issue

Each of these options are discussed in detail below.

3.2.1 OPTION 1 - DO NOTHING

The 'do-nothing' option assumes a business as usual scenario. The current maintenance activities would continue at HB including inspections, preventive work and repair of defects.

The risk of a transformer fault is increasing as the insulation properties continue to deteriorate. Under this option, the transformers will be replaced when they fail. However, this has safety, operational and environmental consequences. Consequences may include:

- Interruption/loss of supply to customers supplied from the station;

- Injury to JEN employees and contractors;
- Damage to the transformer and adjacent assets, and;
- Environment issues (i.e. loss of significant amount of oil).

This option would allow management of the oil leaks issue (Issue 6) but would be unlikely to solve it. The option does not address any of the other two transformer condition issues described in Section 2.2. In particular, the paper insulation condition (Issue 1) would not be resolved.

The 'do-nothing' option is an endorsement of a run to failure strategy that is not consistent with the Primary Plant Asset Class Strategy adopted for this type of plant. This is not appropriate for this type of infrastructure given the consequences of failure for the business and the community.

These scenarios will affect the performance indicators of JEN and have financial implications such as increased cost for replacement of the transformer, loss of performance incentives and the cost of potential injury to employees. This option is reactive by nature and does not address any of the current issues.

3.2.2 OPTION 2 - INCREASED MAINTENANCE & MONITORING

Under this option, the transformers at HB would be more closely monitored and the frequency and range of condition testing would be increased. Re-conditioning of the insulating oil may address any oil-related issues and issues with bushings could be remedied before they developed to any significant degree.

This option does not address either of the paper insulation condition issues and the probability of failure. It is therefore not considered prudent.

3.2.3 OPTION 3 - TRANSFORMER REFURBISHMENT

This option involves removal of the windings, drying out the windings, tightening up of all internal components and reassembly with re-conditioned oil. The issues with transformer oil condition (Issue 6) would be addressed. This refurbishment would be undertaken on-site or in a workshop.

This option does not address the paper insulation condition (Issue 1 and Issue 2), therefore, the probability of failure of the transformer would remain.

This option does not solve the reliability, safety or environmental issues and is anticipated to cost approximately $500k. Essentially there will still be one power transformer remaining in service that is at the risk of failure.

3.2.4 OPTION 4 - TRANSFORMER REWIND

Transformer rewind involves removal of the transformer from site to a transformer manufacture facility. The core and windings would then be de-tanked and the windings removed from the core. New windings would be manufactured and the unit would then be re-assembled, tightened and filled with new oil.

Wilson Transformers have estimated that the cost to undertake this work would be approximately 80% of the cost of a new transformer and the work would take approximately 4 months per transformer.

Wilsons also indicated that the manufacturing cost of a new transformer would be approximately $850k, so the rewinding of the transformer would represent a saving of $170k per unit compared to option 6. The total cost to rewind both transformers including civil works is estimated to be $9.266M.

Undertaking this option would mean that for 4 months, HB would be operating with only one transformer in service, one of which would have a severely deteriorated condition, while the other transformer is being refurbished offsite. The loss of the in-service transformer at any time during this period would result in loss of supply to the entire zone substation.

As HB zone substation is an island, no-load transfers are available to adjacent zone substations; therefore, the entire substation (approximately 8,900 customers) would be off supply until the transformer was repaired. This repair could take days or even months depending on the nature of the failure. This would not only result in massive STPIS penalties but would also affect Jemena's reputation because of the negative media coverage of the event.

The first period when a transformer was off-site would involve the most risk as the remaining in-service transformer would be in poor condition and the probability of failure would be high.

Stressing the existing transformers to this extent given their current condition is seen as an unacceptable risk to customer supply.

Moreover, this option will result in other legacy issues remaining, which include:

- Transformer oil in the ground;
- Outdated and inefficient transformer radiator design, and
- Outdated and aged transformer equipment including core, on-load tap-changer, current transformers etc.

3.2.5 OPTION 5 - TRANSFER LOAD

The permanent transfer of load option involves the transfer of the station's entire load from HB and the temporary or permanent retirement of the zone substation.

Table 2-2 shows that the current maximum demand at HB is 28.8MW. Zone substation HB is an island with no surrounding JEN zone substations, therefore, there is no transfer capacity.

This option would require the creation of at least 57.6MW (n-1) of capacity within a couple of km of zone substation HB to maintain existing levels of reliability. This could only be achieved by constructing a new substation in the area.

In addition to the transformer costs, this option would require installation of new transformer bays including circuit breakers, 11kV feeder circuit breakers and the establishment of new 11kV feeders. A new control building would be required as well as all the associated protection and control equipment.

Establishment of a greenfield zone substation is estimated to be $14.328M, and this is based on the approved business case for zone substation YVE (including overheads). YVE was commissioned in 2014. Adjusting for CPI increases from 2014 to 2019, this cost becomes $16.45M in 2019. This estimate is conservative due to the costs associated with reconfiguration of sub-transmission circuits in well-established urban areas, and the cost of acquiring land; however, the figure will be used as a basis of comparison.

The establishment of a new zone substation to replace HB would not be a prudent method of addressing the existing transformer condition issues at HB. The cost of this establishment would be far more than the cost to replace the transformers at HB.

It is for these reasons that this option is not considered prudent.

3.2.6 OPTION 6 - REPLACE TRANSFORMER

This option involves replacing the existing No.1 transformer with a new modern equivalent and installing it to current standards. A new No.2 transformer will be installed to current standards and the existing No.3 transformer would be retired and scrapped.

This option would address all the condition issues identified in Section 2.2 and resolves the associated safety and reliability issues.

The risk to network performance would be minimised as the first new transformer (new No.2 transformer) could be installed in-between the existing No.1 and No.3 transformers. The second new transformer would replace the existing No.1 transformer still in service. This will mitigate the risk as there are no line circuit breakers. The changeover from old to new would be staged and each of the changeovers would only take approximately three days with no planned customer outages.

The following high-level equipment will be installed in conjunction with the new power transformer:

- Transformers
  - The No.2 transformer is to be replaced with 20/33MVA 66/22kV Yyn0d11 transformer;
  - The transformers will have in-tank vacuum type tap changers;
  - The 11kV cable box must be sized to contain a minimum of three 630mm2 copper XLPE cables per phase;
  - Installation and termination of the 11kV transformer cables (minimum of three 1/c 630mm2 Cu XLPE per phase to their respective circuit breakers) are to achieve a 2500A two-hour rating, and
  - Each transformer shall be supplied with Fibre Optic Sensors to measure the winding hot spot temperature and will be connected to the DRMCC. Asset Management will work with the Project Manager to evaluate this requirement with the transformer manufacturer.
- 66kV Equipment
  - Replacement of the existing 1-2 66kV bus-tie circuit breaker
  - Installation of the new 2-3 66kV bus-tie circuit breaker
  - Replacement of 66kV hardware, bus structures and bus earth switches;
  - Replacement of 66kV Disconnectors/earth switches, and
  - No.1 transformer, No.2 transformer and the TSTS 66kV line surge diverters.
- Cables
  - Installation and termination of the No.1 and No.2 transformer 11kV cables (minimum of 3 x 1/c 630mm2 Cu XLPE per phase to their respective circuit breakers to achieve 2500A minimum cyclic rating).

This option addresses the condition issues identified in Section 2.2 and the risk to network performance would be minimised. This option meets all the technical and financial requirements and is the preferred prudent option. The cost of this option is estimated to be $9.606M ($2019).

3.2.7 OPTION 7 – NON-NETWORK SOLUTIONS

Non-network solutions are alternatives to network augmentation which address a potential shortfall in electricity supply in a region. Such options are considered whenever we face an investment need; they offer the opportunity to defer or avoid capital costs. These solutions are typically better tailored to local needs and enable us to adapt quickly to changing operating conditions.

In the context of the HB Transformer Replacement project, there is no potential for non-network options to defer capital investment as the capital investment is required to upgrade ageing and deteriorated assets and not to address the shortfall in electricity supply.

The following non-network options were considered:

- Embedded generation (a generating unit connected to the distribution network);
- Energy storage (such as batteries which can be charged overnight during the off-peak period enabling electricity to be stored and discharged during peak times), and
- Load curtailment a reduction in consumption during a defined time period. This includes both ceasing to (in part or full) to consume electricity as well as shifting consumption to outside the critical time period.

4. OPTION EVALUATION

This section discusses the economic analysis that was done to identify the most efficient investment option – the preferred option.

4.1 ECONOMIC ANALYSIS

In line with the objective of the National Electricity Rules, Jemena's investment decisions aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market.

To assess benefits against this objective, Jemena has undertaken a probabilistic cost-benefit assessment of options that considers the likelihood and severity of critical network outages. The methodology assesses the expected impact of network outages or asset failures on supply delivery, and combines this with the value that customers place on their supply reliability and compares the result with the costs required to reduce the likelihood and/or impact of these supply outages or asset failures. The table below presents a summary of the cost-benefit assessment undertaken for this project.

4.1.1 SUMMARY OF CREDIBLE OPTIONS' EXPECTED COSTS & MARKET BENEFITS

The basic global parameters used such as discount rate, WACC, depreciation, assessment periods and other assumed constants are included in this analysis.

Table 4-1: Economic Analysis Results Summary

Description ($'000s, $2019)	Option 1 Do Nothing	Option 4 Transformer Rewind	Option 5 Transfer Load	Option 6 Replace Transformer
Total Expected costs	0	9,266	16,450	9,606
Total Expected market benefits	0	105,833	111,474	111,474
Net market benefits	0	96,567	95,024	101,868
Option ranking	4	2	3	1

Based on the above analysis, Option 6 is the preferred option.

5. PROJECT TIMING

There are currently 7 zone substation transformers in service that were installed before 1960. A further 18 were installed over ten years between 1960 and 1970 and most of these are already over 50 years old. The condition of all these units will be monitored and prioritised for replacement.

There are currently three zone substations with significant transformer condition issues on the Jemena Electricity Network. Replacement projects have been prioritised based on their criticality using current condition based test results and CBRM results. These project timings are consistent with the Zone Substation Primary Plant Asset Class Strategy (ELE AM PL 0061). These projects are:

- Zone Substation Essendon (ES) (Installed 1965) – 2019/20;
- Zone Substation Heidelberg (HB) (Installed 1966) – 2020/21; and
- Zone Substation Broadmeadows (BD) (Installed 1968) – 2022/23.

Consequently, the HB transformer replacement project is scheduled to commence in 2020 and to be completed in 2022.

6. REGULATORY TREATMENT

The rationale for this project is to maintain rather than improve network performance through the timely replacement of the aged plant that is in poor condition. Maintaining network performance will be achieved by avoiding the impact of a failure of one or more of the transformers at Zone Substation HB.

If the asset remains in service, its condition will deteriorate, and it may impact employee safety, while the reliability of customer supplies will decrease.

JEN notes that project costs of this nature have been funded in the EDPR capex allowance, and there are no project costs between other assets. Prudent spend of allowance is evident as some options were discarded, while the most efficient of the remaining options is recommended.

Maintaining network performance is consistent with the objectives of the Electricity Primary Plant Asset Class Strategy:

- Achieve a 50-year life; and
- Minimise supply interruptions to customers.

See Appendix A for the Electricity Primary Plant Asset Class Strategy.

7. RECOMMENDATION

This business case proposes a total investment of $9,606 (real $2019) and requires Managing Director's (Band B) approval under the SGSPAA DFA Manual, Annex 3.

It is recommended that Option 6 be adopted and the No.1 transformer at zone sub HB be replaced with new modern equivalent and a new No.2 transformer be installed at HB, with both transformers to be installed to current standards. This option is considered prudent, has a positive net present value and is the preferred option, and will address all known issues.

This option would address all the condition issues identified in Section 2.2, which have a negative impact on safety, reliability and security of customer supply. The project would commence in 2020. The transformer will then be over 54 years old.

Appendix A
Asset Class Strategy

A1. ELECTRICITY PRIMARY PLANT ASSET CLASS STRATEGY

http://ecms/otcs/cs.exe/link/307787079

Appendix B
Project Scope and Delivery Information

Jemena

B1. HIGH-LEVEL SCOPE

1 PRIMARY ELECTRICAL REQUIREMENTS

Primary works for this project shall be carried out to meet the requirements of the relevant standards unless otherwise stated herein.

2 TRANSFORMERS

- The No.1 transformer is to be replaced with 20/33MVA 66/11kV Dyn1 transformer and the No.3 transformer is to be retired and scrapped
- Installation of the new No.2 20/33MVA 66/11kV Dyn1 transformer
- The transformers will have in-tank vacuum type tap changers
- The 11kV cable box must be sized to contain a minimum of three 630mm2 copper XLPE cables per phase
- Installation and termination of the 11kV transformer cables (minimum of three 1/c 630mm2 Cu XLPE per phase to their respective circuit breakers) are to achieve a 2500A two-hour rating
- Each transformer shall be supplied with Fibre Optic Sensors to measure the winding hot spot temperature and will be connected to the DRMCC. Asset Management will work with the Project Manager to evaluate this requirement with the transformer manufacturer.

A. 66KV EQUIPMENT

Replacement of 66kV hardware, including:

- No.1, No.2 and No.3 transformer 66kV Disconnect/earth switches.
- Install No.1 and No.2 transformer 11kV neutral disconnect switches
- Install No.1, No.2 and No.3 66kV bus earth switches.
- No.1 and 2 transformer 66kV surge diverters.
- Two new 66kV CBs (1-2 66kV and 2-3 66kV Bus Tie CBs).
- Three new single-phase 66kV Line VT's.

B. OUTDOOR SWITCHYARD

- Replacement of the 66kV switchyard 240V AC power boxes.

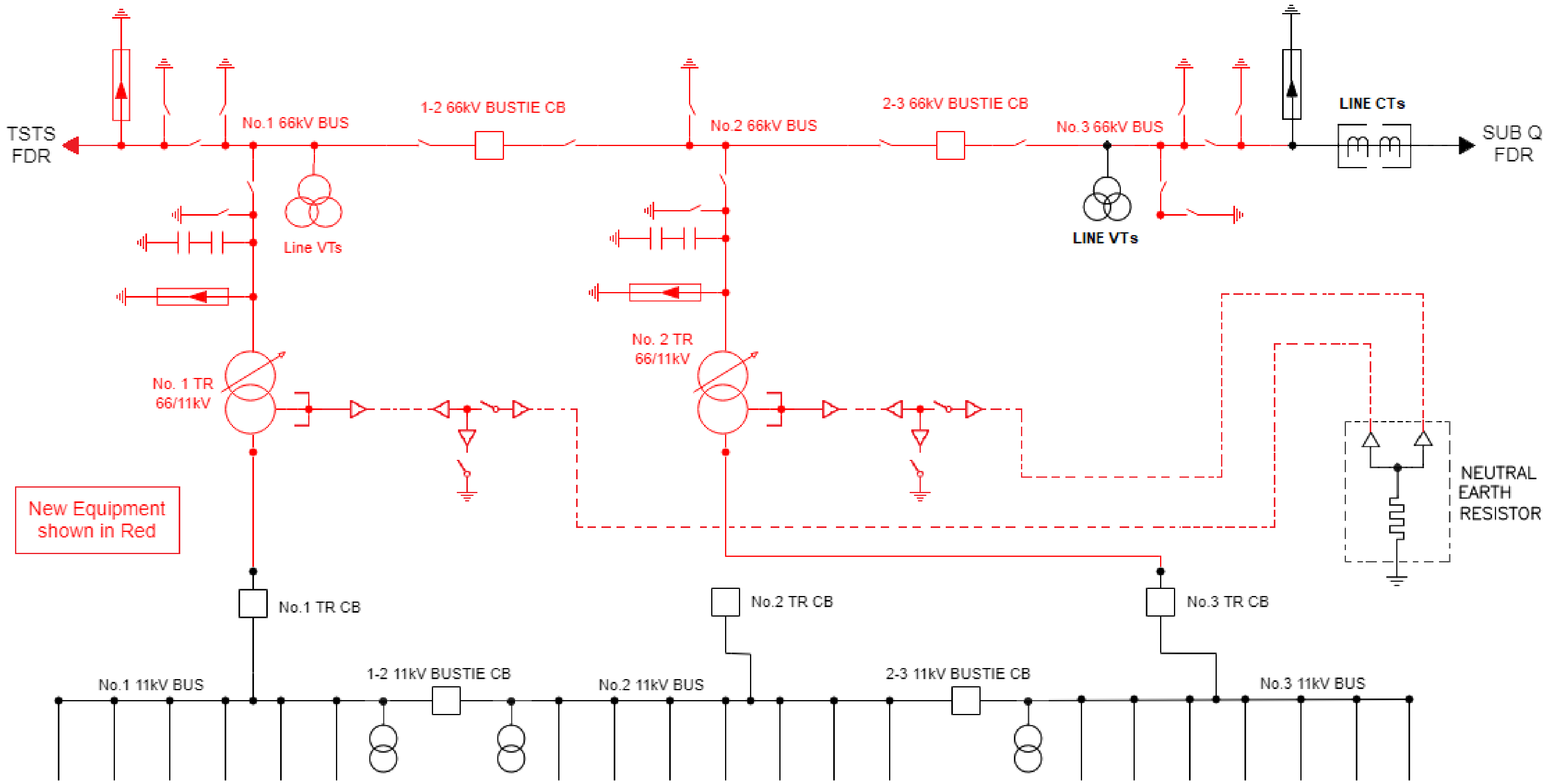
C. CONTROL BUILDING

- Replace the existing DC supply system by a new duplicated DC supply system and upgrade the control building ventilation.

B2. PROJECT DELIVERY APPROACH

Zinfra shall deliver the project. Where the works are to be outsourced, Zinfra shall be responsible for the preparation of all the necessary tender documentation and other associated project requirements.

B3. SINGLE LINE DIAGRAM



Appendix C
Transformer Failure Rate Modelling

TRANSFORMER FAILURE RATE MODELLING FOR COST OF RISK

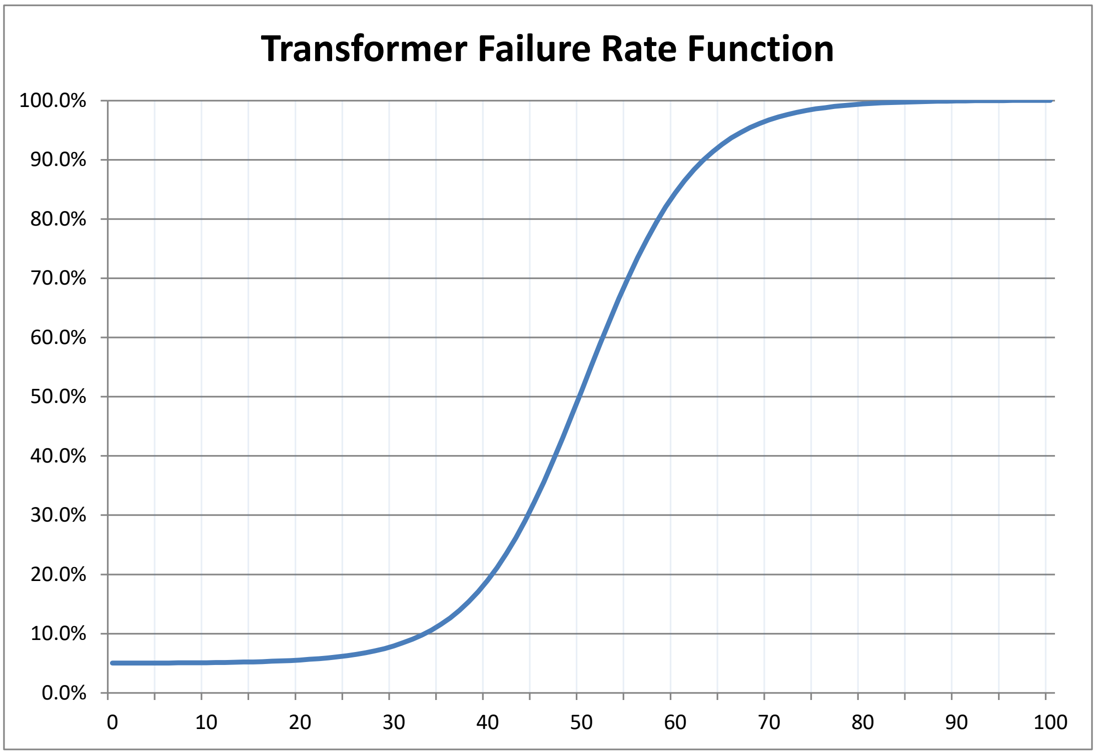
A risk model of future transformer failures based on aging has been used to calculate the cost of risk. This model utilises Perks' formula[1][2] [3].

1. In 1932 W Perks proposed a formula to closely approximate the slower rate of increase of mortality at older ages. This simple statistical model has been used for transformer failures.

Perk's formula: $$f_{(t)} = \frac{A + \alpha.e^{(\beta t)}}{1 + \mu.e^{(\beta t)}}$$

"A" is a constant set at 0.5% to take into account random events other than aging (e.g. lightning).

"A", "b" and "µ" are constants and "t" is years

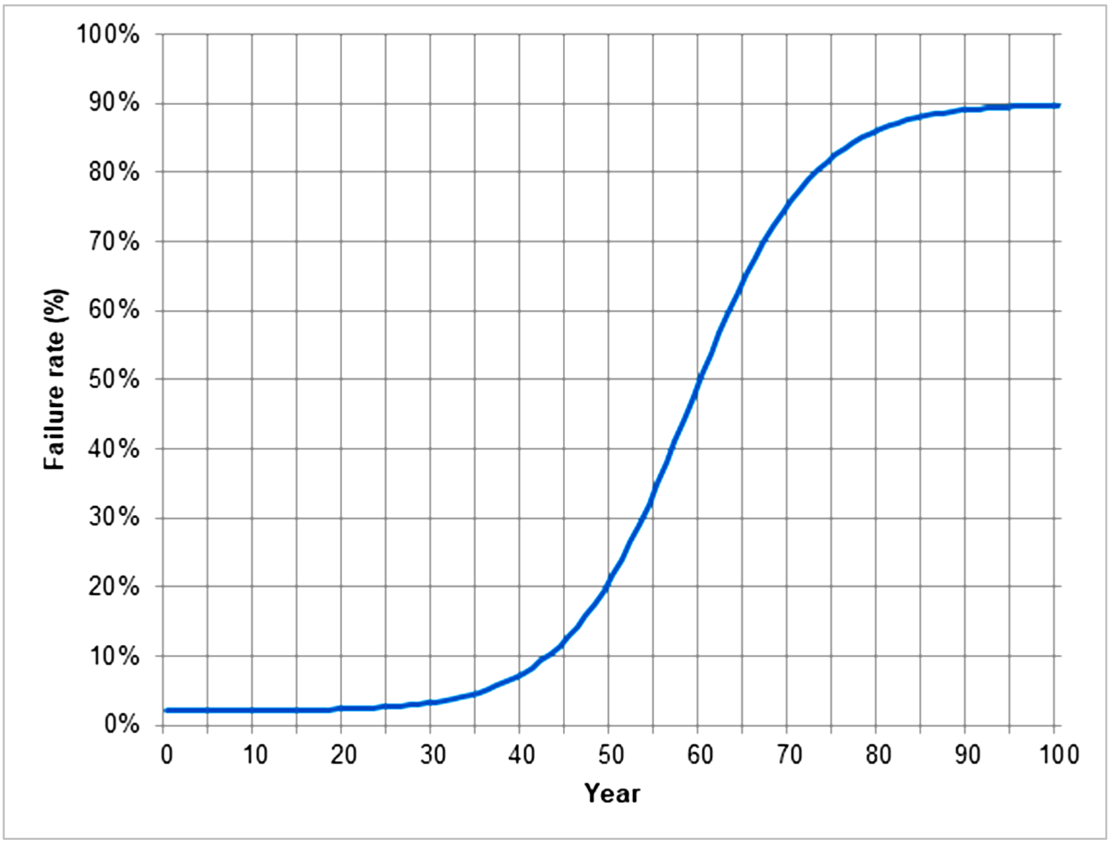


[1] William Bartley, *Analysis of Transformer Failures*, International Association of Engineering Insurers 36th Annual Conference, Stockholm, 2003

[2] Qiming Chen & David Egan, *Predicting Transformer Service Life Using Simplified Perks' Equation and Iowa Curves*, IEEE Power Engineering Society General Meeting, 2006.

[3] Qiming Chen & David Egan, *A Bayesian Method for Transformer Life Estimation Using Perks' Hazard Function*. IEEE Transactions on Power Systems Volume 21 No.4, November 2006.

2. The graph below is perceived as the most appropriate to apply to the JEN fleet of transformers because the JEN network adopts an N-1 loading philosophy, which slows the rate of paper deterioration ultimately extending the life of a transformer. It is for this reason that Perks Transformer Failure Rate Function for a 50-year-old transformer has been extended from 50 years to 60 years of age as per the graph below.



Appendix D

Network Risk Assessment Summary

JEN Asset Specific (Strategic) Risk Assessment

Context statement: Replace Transformers at HB Zone Sub

Participants: Saqib Ikram, Michael Ciavarella, Sandro Bongetti, Diptiman Yadav, Kav Thananjayen

Workshop Date: 15/01/2019

S/No	Business Objective	Risk Type	Risk Title (Identified Risk)	Risk Description (Including Hazard Effect)	Root Causes (Contributing Factors)	Risk Owner	Current Controls	Adequacy of Controls	Current Consequence	Current Likelihood	Current Risk Rating	Action Plans	Target Consequence	Target Likelihood	Target Risk Rating
1	Safety	Health, Safety & Environment (JEN)	Employee and contractor injury	Explosive failure (i.e. explodes and ruptures tank, porcelain fragments and shrapnel are expelled) of transformer due to internal transformer fault or protection relay failure resulting in injury to employee or contractors. Consequence: Major Potential life threatening injury due to equipment failure. Likelihood: Possible Might occur at some stage in the next 5 years due to the condition of the transformers. Historically Jemena has experienced 1 event in 15 years (DVY). In Victoria there have been many events. i.e. RWN, DVY, AP, HSM.	- Assets in deteriorated condition (i.e. cellulose deteriorated, major oil leaks etc.) - Overloaded transformer under N-1 conditions - Fault (i.e. shorted turns, tap changer failure etc.) - Work practices, i.e. poor contract management, poor installation, poor maintenance (low oil therefore low dielectric strength)	Johan Esterhuizen	- Transformer replacement as recommended in JEN PL 00XX Electricity Primary Asset Class Strategy. - JEN Internal Standards for all construction and maintenance (including Asset Specifications). - Communicate current JEN standards. - External ESV audits influences internal compliance culture. - Collective industry experience and assessments agree that previous constructions were in accordance with the standards and good industry practice at the time. JEN continues to monitor the safety performance of these existing assets via: - Asset Inspection Program - conduct monthly operator checks and annual engineering checks and undertake corrective action. - Routine maintenance. - Condition monitoring tests (DGA, paper samples and PDC/RVM tests). - Thermal survey. - Corrective maintenance.	Adequate	Major	Possible	High	Replace transformers	Major	Rare	Moderate
2	Safety	Regulatory & Compliance (JEN)	ESMS compliance	Non-compliant safety performance of transformers. Duty of care to provide a safe working environment. Consequence: Severe Isolated regulatory or policy violations/breaches. Moderate fines or penalties possible. Likelihood: Possible Might occur at some stage in the next 5 years due to the condition of the transformers. Historically Jemena has experienced 1 event in 15 years (DVY). In Victoria there have been many events. i.e. RWN, DVY, AP, HSM.	- Assets in deteriorated condition (i.e. cellulose deteriorated, major oil leaks etc.) - Overloaded transformer under N-1 conditions - Fault (i.e. shorted turns, tap changer failure etc.) - Work practices, i.e. poor contract management, poor installation, poor maintenance (low oil therefore low dielectric strength)	Johan Esterhuizen	- Transformer replacement as recommended in JEN PL 00XX Electricity Primary Asset Class Strategy. - JEN Internal Standards for all construction and maintenance (including Asset Specifications). - Communicate current JEN standards. - External ESV audits influences internal compliance culture. - Collective industry experience and assessments agree that previous constructions were in accordance with the standards and good industry practice at the time. JEN continues to monitor the safety performance of these existing assets via: - Asset Inspection Program - conduct monthly operator checks and annual engineering checks and undertake corrective action. - Routine maintenance. - Condition monitoring tests (DGA, paper samples and PDC/RVM tests). - Thermal survey. - Corrective maintenance.	Adequate	Severe	Possible	Significant	Replace transformers	Severe	Rare	Moderate
3	Return on Investment	Financial (JEN)	Total cost of failure	Explosive failure resulting in damage to single 66/11kV transformer, no loss of supply to customers but total loss of supply to the customers for any fault on the 66kV line supplying the in-service transformer or the failure of the ins-service transformers itself. Subsequent recovery costs. Consequence: Major ($3.5M-$10M) $3.75M (transformer replacement) Based on the failure of DVY Transformer replacement and clean up costs. Likelihood: Possible Might occur at some stage in the next 5 years due to the condition of the transformers. Historically Jemena has experienced 1 event in 15 years (DVY). In Victoria there have been many events. i.e. RWN, DVY, AP, HSM.	- Assets in deteriorated condition (i.e. cellulose deteriorated, major oil leaks etc.) - Overloaded transformer under N-1 conditions - Fault (i.e. shorted turns, tap changer failure etc.) - Work practices, i.e. poor contract management, poor installation, poor maintenance (low oil therefore low dielectric strength)	Johan Esterhuizen	- Transformer replacement as recommended in JEN PL 00XX Electricity Primary Asset Class Strategy. - JEN Internal Standards for all construction and maintenance (including Asset Specifications). - Communicate current JEN standards. - External ESV audits influences internal compliance culture. - Collective industry experience and assessments agree that previous constructions were in accordance with the standards and good industry practice at the time. JEN continues to monitor the safety performance of these existing assets via: - Asset Inspection Program - conduct monthly operator checks and annual engineering checks and undertake corrective action. - Routine maintenance. - Condition monitoring tests (DGA, paper samples and PDC/RVM tests). - Thermal survey. - Corrective maintenance.	Adequate	Major	Possible	High	Replace transformers	Major	Rare	Moderate
			...tal loss of supply	Loss of N-1 capability resulting in a vulnerability to subsequent events. Failure of one in-service transformer resulting in no loss of supply to customers, but total loss of supply to customers for any subsequent fault on the 66kV line			- Transformer replacement as recommended in JEN PL 00XX Electricity Primary Asset Class Strategy. - JEN Internal Standards for all construction and maintenance (including Asset Specifications).								

				RWN, DVY, AP, HSM.											
4	Customers	Operational (JEN)	Failure of one in-service transformer and total loss of supply for any subsequent fault/s	Loss of N-1 capability resulting in a vulnerability to subsequent events. Failure of one in-service transformer resulting in no loss of supply to customers, but total loss of supply to customers for any subsequent fault on the 66kV line supplying the in-service transformer or the failure of the in-service transformer itself (MD forecast 28.8MVA, transformer cyclic rating is 32.4MVA. Consequence: Major Loss of electricity supply to >2% customers (6000) > 24 hrs (during peak demand over summer) Likelihood: Unlikely Might occur at some stage in the next 10 years due to the condition of the transformers. Historically Jemena has experienced 1 event in 15 years (DVY). In Victoria there have been many events. i.e. RWN, DVY, AP, HSM.	- Assets in deteriorated condition (i.e. cellulose deteriorated, major oil leaks etc.) - Overloaded transformer under N-1 conditions - Fault (i.e. shorted turns, tap changer failure etc.) - Work practices, i.e. poor contract management, poor installation, poor maintenance (low oil therefore low dielectric strength)	Johan Esterhuizen	- Transformer replacement as recommended in JEN PL 00XX Electricity Primary Asset Class Strategy. - JEN Internal Standards for all construction and maintenance (including Asset Specifications). - Communicate current JEN standards. - External ESV audits influences internal compliance culture. - Collective industry experience and assessments agree that previous constructions were in accordance with the standards and good industry practice at the time. JEN continues to monitor the safety performance of these existing assets via: - Asset Inspection Program - conduct monthly operator checks and annual engineering checks and undertake corrective action. - Routine maintenance. - Condition monitoring tests (DGA, paper samples and PDC/RVM tests). - Thermal survey. - Corrective maintenance.	Adequate	Major	Unlikely	Significant	Replace transformers	Major	Rare	Moderate
5	Customers	Brand / Reputation / Stakeholders (JEN)	Failure of one in-service transformer and total loss of supply for any subsequent fault/s	Loss of N-1 capability resulting in a vulnerability to subsequent events. Failure of one in-service transformer resulting in no loss of supply to customers, but total loss of supply to customers for any subsequent fault on the 66kV line supplying the in-service transformer or the failure of the in-service transformer itself (MD forecast 28.8MVA, transformer cyclic rating is 32.4MVA. Consequence: Major Loss of electricity supply to >2% customers (6000) > 24 hrs (during peak demand over summer) Likelihood: Unlikely Might occur at some stage in the next 10 years due to the condition of the transformers. Historically Jemena has experienced 1 event in 15 years (DVY). In Victoria there have been many events. i.e. RWN, DVY, AP, HSM.	- Assets in deteriorated condition (i.e. cellulose deteriorated, major oil leaks etc.) - Overloaded transformer under N-1 conditions - Fault (i.e. shorted turns, tap changer failure etc.) - Work practices, i.e. poor contract management, poor installation, poor maintenance (low oil therefore low dielectric strength)	Johan Esterhuizen	- Transformer replacement as recommended in JEN PL 00XX Electricity Primary Asset Class Strategy. - JEN Internal Standards for all construction and maintenance (including Asset Specifications). - Communicate current JEN standards. - External ESV audits influences internal compliance culture. - Collective industry experience and assessments agree that previous constructions were in accordance with the standards and good industry practice at the time. JEN continues to monitor the safety performance of these existing assets via: - Asset Inspection Program - conduct monthly operator checks and annual engineering checks and undertake corrective action. - Routine maintenance. - Condition monitoring tests (DGA, paper samples and PDC/RVM tests). - Thermal survey. - Corrective maintenance.	Adequate	Major	Unlikely	Significant	Replace transformers	Major	Rare	Moderate
6	Asset Management	Health, Safety & Environment (JEN)	Environmental issues (equipment failure)	Power transformer explodes and ruptures tank. The result is oil loss and possible fire. Consequence: Severe Potential oil leak into environment and consequential oil fire and air pollution risk. Likelihood: Possible Might occur at some stage in the next 5 years due to the condition of the transformers. Historically Jemena has experienced 1 event in 15 years (DVY). In Victoria there have been many events. i.e. RWN, DVY, AP, HSM.	- Assets in deteriorated condition (i.e. cellulose deteriorated, major oil leaks etc.) - Overloaded transformer under N-1 conditions - Fault (i.e. shorted turns, tap changer failure etc.) - Work practices, i.e. poor contract management, poor installation, poor maintenance (low oil therefore low dielectric strength)	Johan Esterhuizen	- Transformer replacement as recommended in JEN PL 00XX Electricity Primary Asset Class Strategy. - JEN Internal Standards for all construction and maintenance (including Asset Specifications). - Communicate current JEN standards. - External ESV audits influences internal compliance culture. - Collective industry experience and assessments agree that previous constructions were in accordance with the standards and good industry practice at the time. JEN continues to monitor the safety performance of these existing assets via: - Asset Inspection Program - conduct monthly operator checks and annual engineering checks and undertake corrective action. - Routine maintenance. - Condition monitoring tests (DGA, paper samples and PDC/RVM tests). - Thermal survey. - Corrective maintenance.	Adequate	Severe	Possible	High	Replace transformers	Severe	Rare	Moderate