Jemena Electricity Networks (Vic) Ltd

Replace Coburg South (CS) Zone Substation Switchgear

2024 and 2025 Business Case

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Replace Coburg South (CS) Zone Substation Switchgear

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PREFACE

The intent of this business case document is to provide self-supportive, rigorous documentation to substantiate the need and prudency of an investment for both Jemena and its customers. The business case should assist in determining the strengths and weaknesses of a proposal, 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 switchgear at Zone Substation CS (Coburg South) is at risk of failure due to its poor condition and poses serious safety and security of supply concerns
- To manage the risks this project involves replacement of two 22kV buses with modern arc fault contained switchgear and one 66kV bus tie circuit breaker
- The project will be completed during 2024, 2025 and 2026 at a cost of $8.0M (total project cost, real $2019).

1.1 BUSINESS NEED

Zone Substation CS (Coburg South) consists of two 66kV/22kV power transformers, one 66kV circuit breaker and seven 22kV feeders which supply 23,500 Jemena customers. Refer to Appendix A2 for the Single Line Diagram.

The AEI LG4C (1-2 66kV bus tie) circuit breaker, estimated to be 52 years old, represents a family of breakers with history of mechanical failure and catastrophic bushing failures. Catastrophic failure of the primary insulation risks the safety of employees and security of customer supply. In 2015 at ZSS FE (Footscray East) on the 1-2 66kV bus tie CB one of the bushings was replaced with a spare due to degradation of the insulation identified during condition monitoring testing. Furthermore the CB controls, currently operating at 240V DC, need to operate at 110V DC, which is the current Jemena standard. This type of CB is no longer supported by the manufacturer and spare components are no longer available.

The two indoor 22kV metalclad buses and associated minimum oil circuit breakers manufactured by Sprecher and Schuh type HPTw306-FS (1976) are estimated to be 51 years old and their condition has degraded to a point where employee safety, reliability and security of customer supply will be affected.

Partial Discharge (PD) was detected on the 22kV switchboard during routine PD testing in 2016. An intrusive inspection of the switchboard was carried out subsequently and it revealed visible PD damage on the 22kV busbars and standoff insulators. This indicates that insulation degradation has occurred. The damage due to PD cannot be stopped or reversed. Over voltage excursions due to lightning strikes on the network or switching surges can accelerate the insulation degradation further. This will increase the level of PD. The presence of PD will continue to degrade the insulation which will ultimately cause the insulation to fail catastrophically, resulting in the outage of the plant, which may lead to rotational load shedding of customers.

Recently oil leaks have also been found on the CBs that could lead to CB failure. The construction of these CBs and their deployment means that oil levels in the CBs can only be monitored when the CB is racked out of the service position. The loss of one litre of oil can result in catastrophic failure.

The switchgear at CS is non-compliant with current switchgear standards for electrical arc fault containment standards. This presents a health and safety risk to Jemena personnel, due to active PD at near service voltage. In the event that the insulation fails, the resulting electrical arc and pressure wave will not be contained within the switchgear, and consequently the risk employee health and safety is elevated.

The 22kV switchboard is obsolete and the lack of spares necessary to recover from a catastrophic failure will impact on supply reliability to Jemena customers. This switchboard is no longer supported by the manufacturer and spare components are no longer available. This is a critical issue.

There are five current issues (Refer to Section 2.2 for details) associated with the CS assets.

The following options to address the issues have been considered.

1. Do nothing;
2. Increased Maintenance and Monitoring;
3. 22kV and 66kV Switchgear Refurbishment;
4. Transfer load;
5. Replace 22kV and 66kV Switchgear, and
6. Non-network Solutions

The extent to which each of the identified options addresses the issues is shown in Table OV–1-1 below.

Table OV–1-1: Options Analysis

Condition Issue	**Option 1** Do Nothing	**Option 2** Increased Maintenance & Monitoring	**Option 3** Switchgear Refurbishment	**Option 4** Load Transfer	**Option 5** Replace 22kV & 66kV Switchgear	**Option 6** Non-network Solutions
Issue 1 Switchgear Condition	○	○	◑	●	●	●
Issue 2 Non Arc Fault Containment	○	○	○	●	●	●
Issue 3 Lack of Spare Parts	○	○	○	●	●	●
Issue 4 Insulation Oil Leaks	○	◑	◕	●	●	●
Issue 5 Maintenance Intensive	○	◑	◕	●	●	●
Issue 6 66 kV CBs	○	○	◑	●	●	●

Condition Issue	Option 1 Do Nothing	Option 2 Increased Maintenance & Monitoring	Option 3 Switchgear Refurbishment	Option 4 Load Transfer	Option 5 Replace 22kV & 66kV Switchgear	Option 6 Non-network Solutions
Technically & Financially Viable	○	○	○	○	●	○

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

Refer to Section 3 for a detailed discussion on options analysis.

The least lifecycle cost option in the best interest of the customer, that addresses the aforementioned prominent risks, is to replace the 22kV switchgear.

The new switchgear will conform to current Australian Standards and will mitigate safety concerns, maintain reliability and security of customer supply.

The 1-2 66kV bus tie CB will also be replaced with a new SF6 dead tank circuit breaker as per current Jemena standard.

1.2 RECOMMENDATION

It is recommended that Option 5 be adopted and the two 22kV metalclad buses and the 66kV bus tie CB be replaced with new modern equivalents and installing them to current standards. The replacement of the switchgear is recommended and consistent with regulatory requirements in section 6.5.7 of the National Electricity Rules, and section 3.1 of the Electricity Distribution Code.

This option is considered prudent, has a positive net present value and is the preferred option, and will address all know issues. This option would address all the condition issues identified in Section 0, and the risk to network performance would be minimised.

The new switchgear will conform to current Australian Standards and will mitigate safety concerns, and maintain, reliability and security of customer supply.

The total cost of this option is estimated to be $8.0M (total project cost, real $2019). and the project would commence in 2024. The switchgear will then be over 57 years old.

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 CS 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.

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 Section 2.2 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 $8,040K (real $2019) and requires Managing Director's (Band B) approval under the SGSPAA DFA Manual, Annex 3.

The business case is prepared in relation to regulatory submission for the period 2021-2025.

This project is required to be commissioned by 2025.

Table 1-2: Project Budget Information

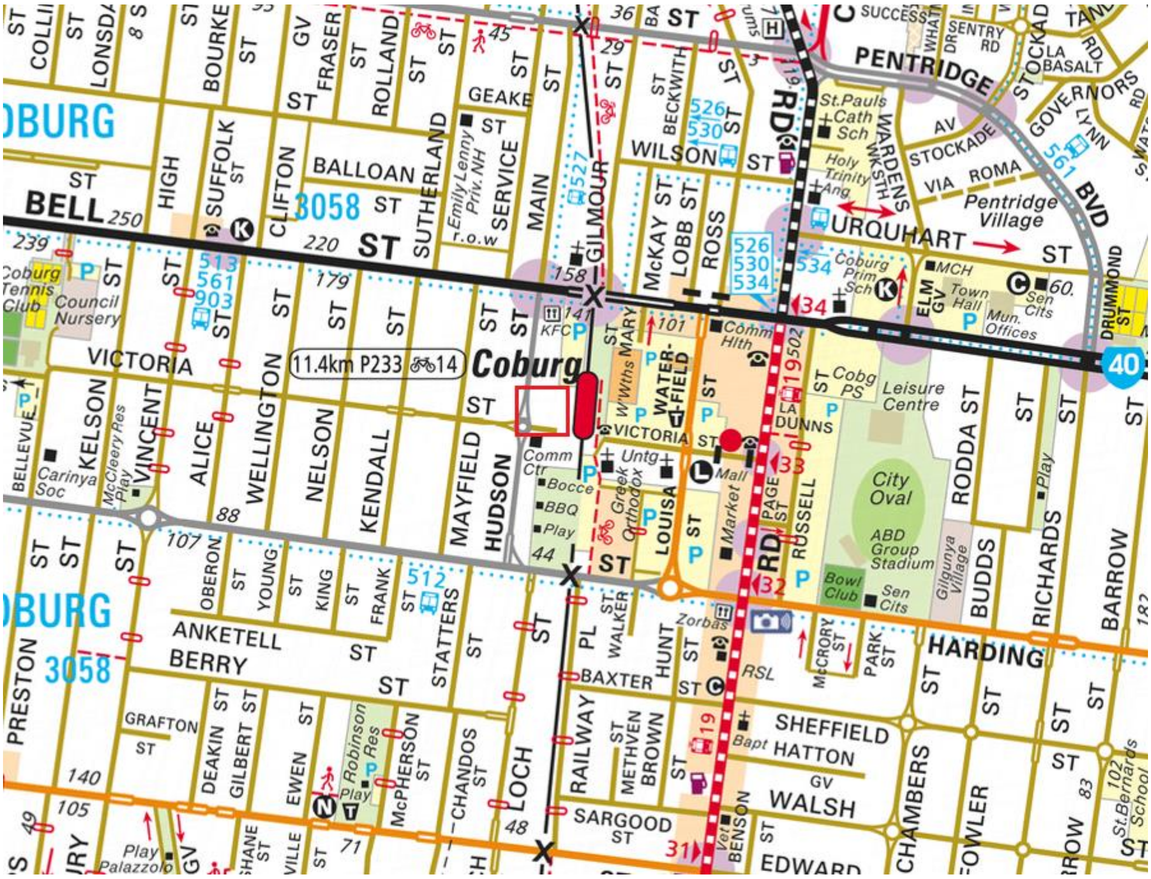
Business Case Spend ($'000s, $2019)	Total
CAPEX	6,841
Overhead Recovery	1,199
Total Business Case Value	**8,040**

2. BACKGROUND

The purpose of this document is to set out the business case for Zone Substation CS (Coburg South) switchgear replacement project, including its regulatory treatment in the JEN building block regulatory proposal and its alignment with JEN's Electricity Primary Plant Asset Class Strategy.

Zone Substation CS was commissioned in 1976 and is located to the north of the Melbourne CBD, at the corner of Victoria Street and Hudson Street in Coburg (Melways ref: 17 H12) as shown in Figure 2–1.

Figure 2–1: Location of Zone Substation CS (Coburg South)



Zone Substation CS (Coburg South) consists of two 66kV/22kV power transformers rated at 30MVA each and has seven 22kV feeders which supply 23,500 Jemena customers. Refer to Appendix A2 for the Single Line Diagram.

The two indoor 22kV metalclad buses and associated CBs at Zone Substation CS are estimated to be 51 years old. The circuit breakers are minimum oil circuit breakers and were manufactured by Sprecher & Schuh type HPtW306-FS in 1967.

2.1 ASSET DETAILS

2.1.1 22KV ASSET DETAILS

The 22kV switchgear installed at CS is briefly described in Table 2-1 and Figure 2–2. The switchgear is metalclad enclosed consisting of a rackable CB compartment. The interrupting mechanisms for each circuit breaker pole is contained within a small oil filled chamber immersed in a thick insulating oil.

Table 2-1: CS Switchgear Details

Designation	Make	Type	Voltage	Current	SECV Spec No.	Year of Manufacture
No.1 22kV Bus	Sprecher & Schuh	HPtW306-FS	22kV	1,200A	70/284	1967
No.2 22kV Bus	Sprecher & Schuh	HPtW306-FS	22kV	1,200A	70/284	1967
No.3 22kV Bus	Sprecher & Schuh	HPtW306-FS	22kV	1,200A	70/284	1967

Figure 2–2: CS 22kV Switchgear

There have been 22 recorded defects associated with the CS 22kV and 66kV switchgear recorded in JSAP (Jemena's Maintenance Management System). In addition 26 defects have also occurred at zone substation NH (North Heidelberg). CS and NH both have the Sprecher & Schuh HptW306 switchgear on the Jemena Network. The replacement of the HptW306 CBs at CS is prioritised over the HptW306 CBs at NH as CS is heavily loaded. These defects are shown in Table 2-2 and Table 2-3.

It has been found that the Sprecher & Schuh HptW306 22kV CBs are leaking oil as a family from "O" ring seals on the drive shafts. This defect was identified during a routine annual audit of the switchgear at ZSS CS in 2013. A program was initiated for the urgent monitoring of oil levels and the replacement of all "O" ring seals in all of these CBs across JEN. As of 2014 all of the CBs on JEN have had their seals replaced.

In 2016 partial discharge (PD) was detected on switchboards at CS and NH during routine PD testing. An intrusive inspection was carried out subsequently and it was identified that there was visible PD damage on 22kV busbars and standoff insulators. The switchboards had non-OEM modifications made to them at the time of installation. These modifications included PVC conduit covers over bus bars to increase BIL and the addition of plastic barrier boards to shield LV CT from the HV busbar connections. In the absence of design documentation, detailing the extent of non-OEM medications of the switchboards, the options to rectify the defects are limited.

The presence of PD and the oil leaks are the most serious defects identified on the Sprecher & Schuh HptW306 switchgear as they have the potential for catastrophic failure.

Table 2-2: CS Switchgear Defect History

Date	CS Asset	Defect	Remedy
04/10/2010	1-2 22kV BUSTIE CB	Failed to close	Investigate, repair
27/02/2012	TTS-CS 66kV FDR CB	Oil leaks	Investigate, oil top up, replace seals
21/06/2012	1-2 22kV BUSTIE CB	Thermal fault	Investigate, repair
09/09/2012	1-2 66kV BUSTIE CB	Oil leaks	Investigate, oil top up, replace seals
24/06/2013	1-2 66kV BUSTIE CB	CB heater not working	Investigate, repair
09/12/2013	NO.2 22kV CAP BANK CB	Spring wind motor malfunction	Investigate, repair
2014	1-2 22KV BUS TIE CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR CS 12 22kV CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR CS 13 22kV CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR CS 2 22kV CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR CS 3 22kV CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR CS 5 22kV CB	Oil leaks	Investigate, oil top up, replace seals

Date	CS Asset	Defect	Remedy
2014	FDR CS 8 22kV CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR CS 9 22kV CB	Oil leaks	Investigate, oil top up, replace seals
2014	NO.1 TRANS 22KV CB	Oil leaks	Investigate, oil top up, replace seals
2014	NO.2 CAP BANK 22kV CB	Oil leaks	Investigate, oil top up, replace seals
2014	NO.2 TRANS 22KV CB	Oil leaks	Investigate, oil top up, replace seals
07/07/2014	NO.2 22kV CAP BANK CB	Defective spring mounting	Investigate, repair
07/07/2014	NO.1 22kV CAP BANK CB	Defective spring mounting	Investigate, repair
29/08/2014	1-2 66kV BUSTIE CB	Oil leaks	Investigate, oil top up, replace seals
13/03/2015	NO.2 22kV CAP BANK CB	Worn spring wind motor brushes	Investigate, repair
18/05/2015	TTS-CS 66kV FDR CB	Oil leaks	Investigate, oil top up, replace seals
23/03/2017	NO.2 22kV BUS JOGGLE	Partial Discharge	Investigate, repair, plan for switchgear replacement

Table 2-3: NH Switchgear Defect History

Date	NH Asset	Defect	Remedy
30/08/2011	FDR NH 16 22kV CB	Equipment failure	Investigate, repair or replace
21/10/2011	NO.1 TRANS 22KV CB	Oil leaks	Investigate, oil top up, replace seals
26/10/2011	FDR NH 5 22kV CB	Oil leaks	Investigate, oil top up, replace seals
27/10/2011	NO.2 22kV CAP BANK CB	Oil leaks	Investigate, oil top up, replace seals
2014	1-2 22KV BUS TIE CB	Oil leaks	Investigate, oil top up, replace seals
2014	2-3 22KV BUS TIE CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR NH 12 CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR NH 13 CB	Oil leaks	Investigate, oil top up, replace seals

Date	NH Asset	Defect	Remedy
2014	FDR NH 2 CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR NH 3 CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR NH 5 CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR NH 8 CB	Oil leaks	Investigate, oil top up, replace seals
2014	FDR NH 9 CB	Oil leaks	Investigate, oil top up, replace seals
2014	NO.1 CAP BANK CB	Oil leaks	Investigate, oil top up, replace seals
2014	NO.1 TRANS 22KV CB	Oil leaks	Investigate, oil top up, replace seals
2014	NO.2 CAP BANK CB	Oil leaks	Investigate, oil top up, replace seals
2014	NO.2 TRANS 22KV CB	Oil leaks	Investigate, oil top up, replace seals
07/07/2014	NO.1 22kV CAP BANK CB	Defective spring mounting	Investigate, repair
07/07/2014	NO.2 22kV CAP BANK CB	Defective spring mounting	Investigate, repair
26/02/2015	NO.2 22kV CAP BANK CB	Defective test plug	Investigate, repair
01/12/2015	NO.2 22kV BUS	Partial Discharge	Investigate, repair, plan for switchgear replacement
12/09/2016	FDR NH9 22kV CB	Kelman trace low current	Investigate, repair
26/09/2016	FDR NH2 22kV CB	Slow 1st trip	Investigate, repair
29/11/2016	FDR NH9 22kV CB	Oil leaks	Investigate, oil top up, replace seals
30/08/2017	1-2 66kV BUSTIE CB	Heater not working	Investigate, repair
20/12/2017	NO.2 22kV CAP BANK CB	Burnt contacts	Replaced contacts
12/02/2018	FDR NH12 22kV CB	Burnt contacts	Replaced contacts

2.1.2 66KV ASSET DETAILS

The 66kV switchgear installed at CS is briefly described in Table 2-4 and Figure 2–3.

Table 2-4: CS 66kV Bus Tie CB Details

Designation	Make	Type	Voltage	Current	SECV Spec No.	Year of Manufacture
1-2 66kV Bus Tie CB	AEI	LG4C	66kV	1,200A	65-66/90	1966

Figure 2–3: CS 66kV Bus Tie CBs

There have been no recorded defects on the 1-2 66 kV Bus Tie CB on JEN; however there are records of this type of CB, in the Victorian Electricity Industry, with a history of defects and catastrophic failures. Please refer to Section 2.2.1, dot point 5 for further details.

2.2 ASSET RISK ANALYSIS

2.2.1 ASSET CONDITION ISSUES

Five current issues associated with the CS assets have been identified and are discussed below:

1. **Condition monitoring tests conducted on the indoor 22kV switchgear indicate that elevated levels of PD (Partial Discharge) are present during normal operating conditions. This indicates that insulation degradation has occurred. The damage due to PD cannot be stopped or reversed. Over voltage excursions due to lightning strikes on the network or switching surges can accelerate the insulation degradation further. This will increase the level of Partial Discharge. The presence of PD will continue to degrade the insulation which will ultimately cause the insulation to fail catastrophically.**

The 22kV switchgear at Zone Substation CS undergo a condition based monitoring regime which is detailed in Electricity Primary Plant Asset Class Strategy. These CBs are currently 54 years old and no longer supported by the manufacturer. Although some circuit breakers/switchboards have continued to operate satisfactorily for over 50 years, a 50-year-old circuit breaker/switchboard is approaching the end of its practical life due to mechanical wear, lack of spare parts, insulation degradation and non-compliance to modern arc fault containment safety standards.

The current Condition summary for the CS switchgear is shown in Table 2-5.

Table 2-5: CS 22kV Switchgear Condition Summary

Insulation Test	No.1 22kV Bus	No.2 22kV Bus
Insulation Resistance	Good	Good
Dielectric Dissipation	Good	Good
Partial Discharge	Poor – Test, Evaluate & Monitor – Initiate replacement	Poor – Test, Evaluate & Monitor – Initiate replacement

Sprecher and Schuh HPtW306-FS circuit breakers installed at zone substation CS are showing signs of age related deterioration. During recent condition monitoring tests they exhibited PD activity which is a sign of degraded insulation. PD is an electrical discharge which occurs in the voids within the insulation and results in irreversible damage due to carbon build up in the voids.

The presence of PD on the switchgear could be attributed to the lack of air gaps between the PVC conduit covers and the solid insulation, especially around exposed copper busbar conductors. However, because of the absence of design documentation detailing the extent of the non-OEM modifications, and a conclusive cause for the elevated PD, it is not feasible to introduce remedial changes as this could exacerbate the issue further.

Partial Discharge levels for new HV plant are typically less than 50pC and consistent with good industry practice. Partial discharge measurements are used in industry to detect defects in HV insulation in either new or aged HV plant. Experience shows that partial discharges have led to a progressive degradation in the dielectric strength of the insulation. For solid insulation, acceptable limits of 10 pC are stated in AS 62271.200-2005 HV Switchgear and Control Gear.

PD was measured at service voltage (phase to ground operating voltage of 12.7kV) on both the No.1 22kV and No.2 22kV buses at CS and consequently there is a risk of a phase-to-ground fault. See Appendix B for PD graphs. The PD levels shown in the PD graphs in Appendix B, at and above service voltage levels range from 60 pC to 150 pC, well in excess of the industry and Australian standards that stipulate a maximum PD level of 50pC.

In reference to the PD graphs presented in Appendix B, the PD levels are present on all voltage levels, including at service voltage. Over voltage excursions above network voltages levels can occur for short durations as a result of lightning strikes on the network or switching surges. These events can accelerate the insulation degradation further, and PD levels can then increase when measured at normal system voltage levels. This will increase the level of PD greater than the last test report, and increase the risk of electrical flashover as the asset ages further.

The presence of PD will continue to degrade the insulation which will ultimately cause the insulation to fail catastrophically as a result of a power arc. Although the early onset of PD can be detected, the damage cannot be stopped or reversed.

2. **The switchgear is non-compliant with current switchgear standards for electrical arc fault containment standards. This presents a health and safety risk to Jemena personnel, due to active Partial Discharge at service voltage. In the event that the insulation fails, the resulting electrical arc and pressure wave will not be contained within the switchgear, and consequently the risk employee health and safety is elevated.**

   The switchgear in not compliant with current safety standards. In the event of a bus or circuit breaker fault, the over pressure may cause the metalclad housing to rupture, releasing gas pressure and hot oil which is potentially a fire risk. Such an event can occur due to over voltage excursions due to lightning strikes on the network or switching surges which can accelerate the insulation degradation further. This will increase the level of PD greater than the last test report - high level of PD is a sign that insulation is deteriorating and over time will lead to a failure of the insulation. New switchgear is designed and type tested to AS-62271.200 to provide a safe work place for personnel and reduce consequential damage.

3. **The switchboard is obsolete and the lack of spares necessary to recover from a catastrophic failure may impact supply reliability to Jemena customers. This switchboard is no longer supported by a manufacturer and spare components are no longer available.**

   Spare circuit breaker components are limited and in most cases non-existent. Spares have been managed by cannibalising redundant circuit breakers; this is not a long term solution, as there are no more redundant circuit breakers available. Performing repairs following a catastrophic failure will be difficult and may not be possible with the existing assets.

4. **The switchgear has a history of oil leaks from the circuit breaker**

   The CBs are minimum oil circuit breakers and are installed at Sub NH, CS, FW and FE. In 2013 during routine inspections oil leaks were found on these CBs that could have led to CB failure. The construction of these CBs and their deployment means that oil levels in the CBs can only be monitored when the CB is racked out of the service position. Being minimum oil breakers the total oil volumes held in each CB pole are small. The loss of one litre of oil can result in catastrophic failure. It has been found that the CBs are leaking due to a “O” ring seals on the drive shafts. A program was initiated for the urgent monitoring of the oil levels in all of these CBs and the replacement of all seals. As of 2014 all of the CBs on JEN have had their seals replaced. This however doesn't guarantee that the "O" ring seals will not leak in the future and as stated earlier, there is no mechanism to check for oil levels in the CB while they are in service and racked in. The maintenance plans for the CBs have been reviewed.

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

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

There were two catastrophic failures of this type of CB at Brooklyn and one at West Melbourne Terminal Stations in the late 1990's and early 2000's and these failures related to the 66kV bushings as the bushing DLA (Dielectric Loss Angle) had deteriorated to point causing failure.

These CBs are no longer supported by the manufacturer and consequently spare components such as 66kV bushings, turbulators, solenoids and mechanism components are no longer available. The failures of the 66kV bushings is a risk to the safety of field crews. Continued maintenance and testing will not prevent the failure of a bushing as the DLA and PD continues to deteriorate. The cost of engineering new replacement bushings, procurement and installation would be comparable to a new CB installed. Replacement of the bushings alone does not address the mechanical wear and lack of spare parts

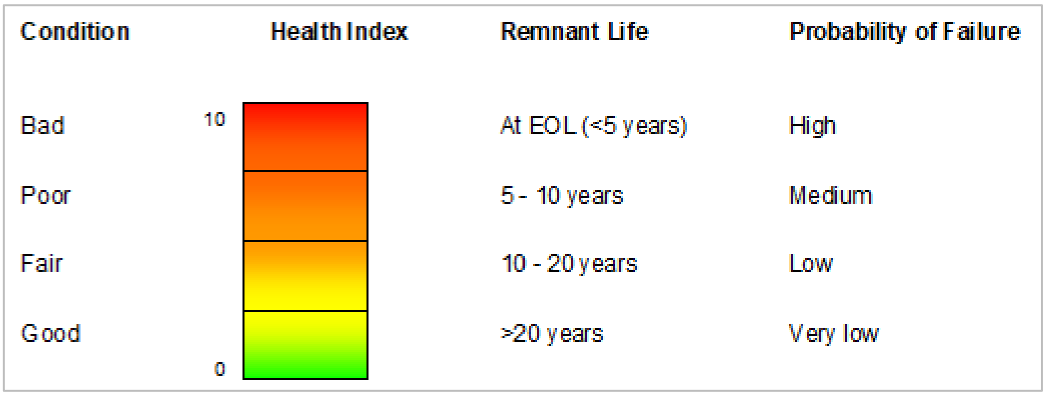
There has been a defect identified in the mechanism of these CBs involving the retaining of a shaft by a washer that is peened on the end of the shaft. This indicates component failure due to mechanical wear and has resulted in damage to the mechanism. A new component was designed and manufactured as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

2.2.2 RISK ASSESSMENT

Condition Based Risk Management (**CBRM**) modelling has been introduced for switchgear assets and is used to assist in the development of asset investment plans using existing asset data and other information. A description of the model and the results for zone substation related assets is in document 'Jemena CBRM Report – Zone Substation Assets', and in the Asset Class Strategies.

CBRM develops a Health Index for each asset based on a scale from 0 to 10. Values of health index in excess of seven represent serious deterioration and a need to plan for replacement before failure occurs is necessary.

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 probability of failure. The concept is illustrated schematically below.



For the 22kV CBs, the CBRM modelling results for the current health index (Y0) and the replacement year health index (2025, Y6) are presented in Table 2-6 below.

Table 2-6: CS 22kV CBs Health Index Results

Designation	Make	Type	HI Y0	HI Y6
1-2 22KV BUS TIE CB	SPRECHER & SCHUH	HPTW306-FS	5.77	7.12
FDR CS 12 CB	SPRECHER & SCHUH	HPTW306-FS	7.13	9.08
FDR CS 13 CB	SPRECHER & SCHUH	HPTW306-FS	6.76	8.62
FDR CS 2 CB	SPRECHER & SCHUH	HPTW306-FS	7.13	9.08
FDR CS 3 CB	SPRECHER & SCHUH	HPTW306-FS	7.13	9.08
FDR CS 5 CB	SPRECHER & SCHUH	HPTW306-FS	7.13	9.08
FDR CS 8 CB	SPRECHER & SCHUH	HPTW306-FS	7.13	9.08
FDR CS 9 CB	SPRECHER & SCHUH	HPTW306-FS	7.13	9.08
NO.1 TRANS 22KV CB	SPRECHER & SCHUH	HPTW306-FS	6.42	8.09
NO.2 CAP BANK CB	SPRECHER & SCHUH	HPTW306-FS	7.7	9.87
NO.2 TRANS 22KV CB	SPRECHER & SCHUH	HPTW306-FS	6.42	8.09

The figures in the table above indicate that the CBs are in a poor to bad condition currently, and will be in a severely deteriorated condition in 2025 if replacement isn't undertaken. This modelling result is consistent with the issues identified.

For the 66kV CB, the CBRM modelling indicates that the CS 1-2 66kV bus tie CB has a current health index (Y0) result of 5.45. This indicates that the CB is in a poor condition. In Year 6 (2025, Y6), the CB result becomes 6.81. This modelling result is consistent with the issues identified.

CS 22kV Indoor Switchgear Failure Risk

Failure Modes

The failure modes of the CS 22kV switchgear can include:

- Mechanical failure (failure to open or close);
- Insulation medium degradation;
- Lightning and other line surges;
- Inadequate maintenance; and
- Design/manufacturing errors.

Due the deteriorated condition of the switchgear, insulation failure is likely occur.

Likelihood of Failure

The probability of a 22kV switchgear failure can only be estimated from limited historical data, engineering experience and condition test reports. From Table 2-2, the failure modes have been summarised below:

- Insulation degradation due to PD;

- Thermal condition;
- CB trip free; and
- Leaking oil

The incidence of oil leaks associated with the CS switchgear is increasing and will ultimately necessitate another major maintenance work to replace gaskets and 'O' rings.

There are 26 Sprecher and Schuh HPtW306-FS CBs installed at CS and NH and 50 recorded faults associated with these CBs in 10 years. The major issue is the presence of PD, above acceptable limits, at service voltage and the impact on personnel safety and the lack of spares to recover from a catastrophic failure. The insulation will continue to degrade over time due to the presence of PD. PD levels will consequently rise and failure will ultimately occur. Refer to section 2.2.1 - Asset Condition.

Catastrophic insulation failure can be triggered by lightning and other line surges. Insulation degradation at normal service voltage can be cyclical due to temperature variations or linear increase over the same period, ultimately resulting in failure. Based on CBRM it is expected that one 22kV indoor CB could fail beyond repair due to bad condition in the next 10 years, The probability of the CS 22kV CB failing is taken to be 1/5=20%pa. This failure rate is likely to increase with age.

Consequence of Failure

The consequence of a catastrophic failure of the 22kV switchgear at CS would likely be interruption of supply to the entire station due to smoke and potential fire. The switchgear contains a small oil volume for insulation and to interrupt current. The scenario considered is the loss of both 22kV buses due to a bus section failure within the bus tie CB. It is likely that all of the station customers will be off supply for 1 hour until transfers are completed to nearby zone substations. The 10% POE (Probability of Exceedance) MD (Maximum Demand) at CS is 59.7MVA, the emergency transfer capacity to nearby zone subs is 13.4MVA. This means that the remaining 75% of customers would be off supply for up to 6 hours whilst damage was assessed and faulted bus is isolated from the second bus.

Network Performance

The network performance considered is for the initial failure event.

The network performance impact (S Factor cost) is associated with this scenario would be:

6hrs x 60(mins) x $0.90/min + 23,500 x 3/4 (Customers) x $56.56/Cust = $1,029k.

1hrs x 60(mins) x $0.90/min + 23,500 (Customers) x $56.56/Cust = $1,383k.

CAPEX

The capital expenditure associated with a single permanent failure is estimated to be $3.8M. This represents the equipment replacement costs (2 x 22kV buses) and is the same value as a planned replacement project. This capital expenditure is based on estimates prepared by our Project Managers

OPEX

The operating expenditure associated with a single permanent failure is estimated to be less than $100k. This represents the costs associated with the forced outage resulting from the bus failure including activities such as network operations to restore supply, repairs to other equipment and any safety related costs.

Total Cost of Risk

The worst case cost of risk for a bus failure has been determined using the results outlined above. This represents the annual potential impact.

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

= ($2.4M + $3.8M + $100k) x 20%

= $1260k p.a.

CS 66kV CB Failure Risk

Failure Modes

The failure modes of a circuit breaker can include:

- Bushing insulation failure;
- Mechanical failure (failure to open or close);
- Insulation medium degradation;
- Lightning and other line surges;
- Inadequate maintenance; and
- Design/manufacturing errors.

A CB can fail due to thermal, electrical or mechanical factors however whilst a typical failure mode is difficult to determine, most failures involve a failure to operate.

Likelihood of Failure

The probability of a 66kV CB failure at CS can only be estimated from knowledge of other failures of CB from that family. There were two catastrophic failures of this type of CB at Brooklyn and one at West Melbourne Terminal Stations in the late 1990's and early 2000's and these failures related to bushings.

There have been numerous other failures of this type of CB and these include:

- 1984 – AW – Failed to close;
- 1983 – ERTS – Damaged during electrical storm;
- 1986 – TTS – Damaged during electrical storm;
- 1986 – HTS – Failure to trip;
- 1994 – CW – Failed to trip;
- 2000 – AW – Failed to trip;
- 2001 – CS – Failed to trip; and
- 2010 – HB- Failed to operate

The likelihood of a mechanical failure is low as these 66kV CBs are not called on to operate due to faults very often. However not all failures can be identified during maintenance. Refer to section 2.2.1 - Asset Condition.

The ten failure observations mentioned above have occurred in the past thirty years giving a probability of failure of 1 in 3 years. Given that 9 of this type of CBs are in service on the JEN, the probability of the CS 66kV CB failing is taken to be 1/3/9=3.7%.

In consideration of a catastrophic bushing failure of 3 in 15 years and a population of 9 CBs, the probability of the CS 66kV CB failure scenario is taken to be 3/15/9~2.22%.

Consequence of Failure

The consequence of a catastrophic failure of the 66kV CB at CS would likely be interruption of supply to the entire station. It is likely that the station could be off supply for up to 1 hour whilst damage was assessed, any necessary minor repairs undertaken and supply restored. The amount of clean up would be minimal given the low oil volumes involved. Any further similar event will result in significant customer outages.

The CB would need to be replaced and the 2 transformers at CS would be on a single 66kV line contingency for approximately 4 months whilst the replacement was procured and installed.

Network Performance

The network performance impact (S Factor cost) is associated with this scenario would be:

1(hr) x 60(mins) x $0.90/min (SAIFI) + 23,500 (Customers) x $56.56/Cust (SAIDI) = $1,383k.

CAPEX

The capital expenditure associated with a single permanent failure is estimated to be $300k. This represents the equipment replacement costs and is the same value as a planned replacement project.

OPEX

The operating expenditure associated with a single permanent failure would not be significant and is estimated to be less than $100k. This represents the costs associated with the forced outage resulting from the CB failure including activities such as network operations to restore supply, minor repairs to other equipment and any safety related costs.

Total Cost of Risk

The worst case cost of risk for a CB failure has been determined using the results outlined above. This represents the annual potential impact.

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

= ($1.38M + $300k + $100k) x 2.22%

= $39.5k p.a.

Due to the age and condition of the assets mentioned above, the above cost of risk will continue to increase until the assets are removed from service.

2.3 PROJECT OBJECTIVES AND ASSESSMENT CRITERIA

Objective

The objective of the project is to determine the most appropriate strategy for the nominated assets to maintain customer supply reliability at CS 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 of this document to identify the best possible option. The options will be benchmarked against the risk assessment from Section 2.2 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.

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.

In respect to the nominated assets, Jemena seeks to comply with these regulatory obligations through the development and implementation of the Primary Plant Asset Class Strategy.

Assessment Criteria

The assessment criteria by which projects will be assessed against and the extent to which each of the identified options address the six asset condition issues are described in Section.

2.4 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.

Competitiveness and adaptability are both critical factors for the Electricity Distribution market as it moves towards a more decentralised operating model. One major change occurring at present is the need for the network to enable and host the deployment of rapidly expanding Distributed Energy Resources (DER) such as solar PV and battery storage.

JEN has commenced small-scale trials of technology that will enable the network to host DER in a more adaptable and effective way to enable two-way power flows to occur on the network in a controlled manner. JEN seeks to ensure that 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 Asset Business Strategy (ABS) and annual planning reports.

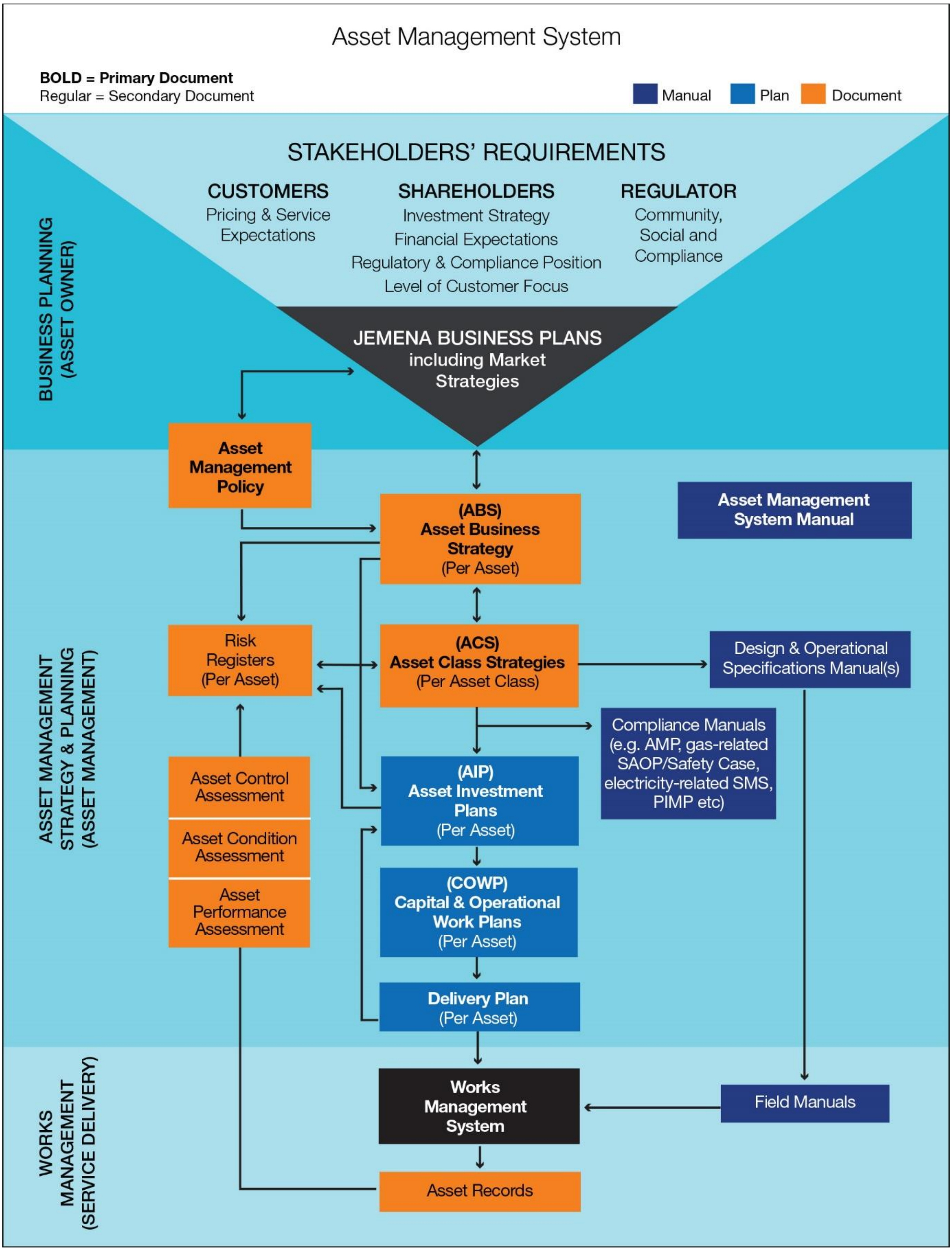
JEN must comply with regulatory obligations; these are incorporated into the development and implementation of its ZSS Primary Plant Asset Class Strategy (ELE AM PL 0061). The Asset Class Strategy creates a line of sight between the JEN Business Plan and the Asset Management Plan.

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 and will increase supply security and maintain reliability. By completing this project, JEN can reduce its exposure to the possibility of litigation by authorities due to an injury or environmental incident.

Figure 2–4 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 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 2–4: 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. 22kV and 66kV Switchgear Refurbishment
4. Transfer load
5. Replace 22kV and 66kV Switchgear
6. Non-network Solutions

3.2 DEVELOPING CREDIBLE OPTIONS COSTS & BENEFITS

The following section discusses the feasibility, practicality, costs and benefits associated with each of the credible options in order to identify which of these to be taken forward for further evaluation.

Note that all expected option costs include overheads.

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 ZSS. The asset condition risk would remain until the assets are either replaced or decommissioned.

A comparison of the six options listed above and the issues they address is shown in below table.

Table 3-1: Options Analysis

Condition Issue	**Option 1** Do Nothing	**Option 2** Increased Maintenance & Monitoring	**Option 3** Switchgear Refurbishment	**Option 4** Load Transfer	**Option 5** Replace 22kV & 66kV Switchgear	**Option 6** Non-network Solutions
Issue 1 Switchgear Condition	○	○	◑	●	●	●

Condition Issue	**Option 1** Do Nothing	**Option 2** Increased Maintenance & Monitoring	**Option 3** Switchgear Refurbishment	**Option 4** Load Transfer	**Option 5** Replace 22kV & 66kV Switchgear	**Option 6** Non-network Solutions
Issue 2 Non Arc Fault Containment	○	○	○	●	●	●
Issue 3 Lack of Spare Parts	○	○	○	●	●	●
Issue 4 Insulation Oil Leaks	○	◑	◕	●	●	●
Issue 5 Maintenance Intensive	○	◑	◕	●	●	●
Issue 6 66 kV CBs	○	○	◑	●	●	●
Technically & Financially Viable	○	○	○	○	●	○

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

3.2.1 OPTION 1 - DO NOTHING

The do nothing option assumes a business as usual scenario. The current maintenance activities would continue including inspections, condition monitoring, preventive work and repair of defects. Maintenance will not improve the insulation condition and PD cannot be prevented when the defect is imbedded within the insulation. In this case maintenance is inadequate to maintain reliability. Increased condition monitoring tasks will be needed to identify when safety restriction limiting access to the switchgear would need to be put in place. These tests would continue until the switchboard condition is at imminent risk of catastrophic failure and it would then be taken out of service, thus placing the supply reliability at increased risk.

This option does not address any of the six condition issues described in Section 2.2. In particular, the 22kV switchgear condition (Issue 1) would not be resolved and the probability of failure of two buses would remain. In event of a bus failure, it is anticipated that load transfer or load shedding would be required.

The switchgear insulation is in poor condition and the degradation that has occurred is irreversible. For this reason, option 1 is not considered. This option is not credible as the point of failure cannot be predicted even though condition testing is implemented, the frequency of future tests may not target the point of failure in time and the switchboard will fail catastrophically in service.

Given the criticality of this issue, it is not recommended to pursue any option that does not address it.

3.2.2 OPTION 2 - INCREASED MAINTENANCE AND MONITORING

Under this option, the CS switchgear would be more closely monitored and the frequency and range of condition testing would be increased. The ultimate failure of the 22bus cannot be prevented if the switchgear remains in-service, regardless of the maintenance and monitoring program. Condition of the insulation will continue to deteriorate until ultimate failure occurs impacting on reliability and safety. For this reason, Option 2 is not considered.

This option does not address any of the six issues described in Section 2.2. In particular, the asset condition of the 22kV and 66kV switchgear would not be resolved and the risk of failure of these assets and impact on personnel safety would remain.

Given the criticality of this issue, it is not recommended to pursue any option that does not address it.

3.2.3 OPTION 3 - SWITCHGEAR REFURBISHMENT

22kV switchgear refurbishment is not possible as the replacement of individual busbar or bushings is no longer supported by the manufacturer, and any such action if possible would be cost prohibitive. This option would only address oil leaks, and the switchgear performance, safety and reliability would not change from the original design in 1967 which does not conform to current Australian safety standards for arc fault containment. Research and development costs, type testing, design work, installation and commissioning could possibly be much more than the project cost to replace the switchboard.

The refurbishment of switchgear which is 51 years old is not recommended, and it would not be technically feasible. Spare parts are not available and the switchgear is beyond 51 years old as well as being non-compliant to current safety standards, in particular the arc fault containment.

66kV bushing replacement (if replacements are available) for the LG4C CB only partially addresses the issues associated with this CB. Spare parts for the CB are lacking; bulk oil presents a fire risk if the bushings fail catastrophically, and the CB is maintenance intensive.

It is for these reasons that this option is not considered as a credible option.

3.2.4 OPTION 4 - TRANSFER LOAD

The transfer load option involves the transfer of all load from CS and the temporary or permanent retirement of the zone substation. If all load was transferred away from CS then the substation could either be demolished and the land sold or simply mothballed until an appropriate time when the substation could be rebuilt and re-commissioned.

This option would solve all six of the current condition issues at CS.

Although approximately 1/4 of the load can be transferred to adjacent feeders without any capital investment, this would be restrictive on any further network operations. There would be no further contingencies available.

In the event of the CS switchgear failing, which represents all of the station load, load transfers and load shedding will need to be in place for approximately 8 months while a new switchboard is procured, installed and commissioned. Any further significant event may result in rotational load shed.

The current maximum demand at CS is 59.7MW. This would require two additional 33MVA transformers, 22kV switchgear, new feeders, and an extended control building with all associated protection and control equipment for a new zone substation.

Establishment of a green field zone substation is estimated to be $16M and this is based on the approved business case for zone substation YVE (including overheads and escalation to 2018). YVE was commissioned in 2014. This estimate is conservative due to the costs associated with establishing 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.

Augmenting an existing zone substation or establishment of a new zone substation to replace CS would not be a prudent method of addressing the existing asset condition at CS. The cost of this establishment would be far in excess of the cost to replace the switchgear at CS.

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

3.2.5 OPTION 5 - REPLACE SWITCHGEAR

This option involves replacing the existing 22kV and 66kV switchgear with new modern equivalents and installing them to current standards. This would address all the condition issues identified in Section 2.2 and will maintain safety, reliability and security of customer supply.

The new indoor metalclad switchgear would conform to current safety standards including arc fault containment.

The total cost of this option is estimated to be $8.0M (total project cost, real $2019) and the project would commence in 2024. The switchgear will then be over 58 years old.

3.2.6 OPTION 6 – 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 CS Switchgear 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 Load Transfer	Option 5 Replace Switchgear
Total Expected costs	0	16,000	8,040
Total Expected market benefits	0	7,237	7,237
Net market benefits	0	-8,763	-803
Option ranking	3	2	1

This identifies option 5 as the recommended solution. 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.

5. PROJECT TIMING

The 22kV Sprecher & Schuh CBs at CS suffer from a number of issues The major issue is the presence of PD at service voltage and the impact on personnel safety and the lack of spares to recover from a catastrophic failure. The insulation will continue to degrade over time due to the presence of PD. PD levels will consequently rise and failure will ultimately occur. Refer to section 2.2.1 - Asset Condition.

Catastrophic insulation failure can be triggered by lightning and other line surges anytime. Insulation degradation at normal service voltage can be cyclical due to temperature variations or linear increase over the same period, ultimately resulting in failure. Based on CBRM it is expected that one 22 kV indoor bus could fail beyond repair due to poor condition in the next 10 years. This failure rate is likely to increase with age.

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

For the 22 kV CBs, the CBRM modelling indicates that the current average health index of the 22kV CBs is 6.56. This indicates that the CBs are in a poor condition. This modelling result is also consistent with the issues identified. In Year 6 (2025), the average highest CB result becomes 7.71.

For the 66 kV CBs, the CBRM modelling indicates that the CS 1-2 66 kV bus tie CB has a current health index result of 5.45. This indicates that the CB in poor condition. This modelling result is also consistent with the issues identified. In Year 6 (2025), the CB result becomes 6.32.

Consequently, this project is scheduled to commence in 2024 and be completed in 2025.

6. REGULATORY TREATMENT

The purpose of this project is to maintain rather than improve network performance through the timely replacement of 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 22kV Buses at CS.

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

- Achieve a 50 year life; and
- Minimise, without incurring excessive cost (i.e. maintaining prudency and efficiency of expenditure), supply interruptions to customers.

If the asset remains in service beyond its nominal lifespan, its condition will deteriorate and impact employee safety, and the reliability of customer supplies will decrease.

7. RECOMMENDATION

This business case proposes a total investment of $8.0M (total project cost, real $2019) and requires Managing Director's (Band B) approval under the SGSPAA DFA Manual, Annex 3.

It is recommended that Option 5 be adopted and the two 22kV indoor switchboards and one 66kV bus tie CB be replaced with new modern equivalents and installing them to current standards. The new 22kV switchboard will be fully rated, arc fault contained, utilising vacuum circuit breakers.

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 total cost of this option is estimated to be $8.0M (total project cost, real $2019) and the project would commence in 2024. The switchgear will then be over 58 years old.

Appendix A
Project Scope and Delivery Information

A1. 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.

1.1. TRANSFORMERS

At the completion of the project, The No.2 transformer will be connected to the new No.3 22kV bus, and the No.1 transformer will be connected to the new No.2 22kV bus. In the future when the No.3 transformer and No.1 22kV bus is installed, all transformers will be reconnected to their appropriate bus.

The No.1 and No.2 transformers require new 66kV CTs to be installed. The existing (x3) CTs per phase are installed within the 66kV turrets. The No.1 transformer 66kV bushings (x4) will be replaced with new ABB GSA type. New turrets, CTs (x4) per phase and 66 kV bushings will be fitted to the No.1 and No.2 transformers. The feasibility of this work will need to be verified.

Transformer oil bunds are to be cleaned, transformer oil leaks rectified and any paint missing on transformers to be touched up. No.3 Transformer conservator has rust which needs to be attended to and cleaned, primed and touched up with paint.

1.2. 66KV EQUIPMENT

The erection and connection of 66kV equipment indoors:

- Installation of a new dead tank bus tie CB, six single phase VTs and line entry surge arresters on the TTS FDR and sub CN FDR.

Replacement of 66kV hardware, including:

- Disconnectors/earth switches.
- The TTS FDR and sub CN DFR disconnect switch will be fitted with an MOD drive mechanism to mitigate risk to customer supplies while the 22kV bus is being replaced. The MOD will need to have local and remote control functionality from the Collins Street control room to restore the No.1 or No.2 transformers following a sustained fault on a 66kV Feeder.
- MODs are also needed for No.1, 2 and 3 (future) Transformer 66kV disconnector switches to satisfy the requirement of a Smart Substation.
- Install 66kV bus earth switches.
- New spherical earthing receptacles as required to replace the cone earths.

1.3. 22KV INDOOR EQUIPMENT

The old Sprecher and Schuh 22kV switchgear will be replaced. The Sprecher and Schuh 22kV panels including CB's will be retained as spares equipment for ZSS NH as per directions in section 12.1 - Retired assets. All maintenance tools for the Sprecher and Schuh 22kV switchgear and LG4C CB's will be relocated to ZSS NH.

To facilitate the replacement of the 22kV switchgear and minimise risk to customer supplies during the cut over stages, a new No.3 22kV bus will be established to supply feeders from the old No.2 22kV bus. In the same way, a new No.2 22kV bus will be established to supply feeders from the old No.1 22kV bus. This has been further explained in the staging plan, section 8.

A total of 14 circuit breakers with associated VT's, earth switch and joggle compartments are required to complete the No.2 and No.3 22kV buses. Refer to the Single Line Diagram, in the Appendices.

A new HV cable basement will be installed for the new 22kV switchboards and future No.1 22kV bus.

A false floor needs to be installed to support the switchgear over the cable basement. False flooring shall be installed around the switchgear where required.

No.1 and No.2 22kV switchboards are to be replaced with a new 22kV metal enclosed, fully arc contained switchboard.

The new 22kV switchboard will consist of:

- Two off 22kV 1250A buses.
- Two 3 phase five limb (or 3 x 1 phase per bus) star connected transformer VT with a single secondary winding, for each bus.
- Two 22kV bus joggles.
- Two 22kV transformer circuit breakers of 1250A rating.
- Two 22kV bus tie circuit breakers of 1250A rating.
- Eight 22kV feeder circuit breakers of 630A rating.
- 22kV panels to be sequenced as shown on the Single Line Diagram (refer Appendix).
- Two 22kV capacitor bank panels with integral earth switches. Note the existing cap bank will be rated up to 12MVAr in the future.

  To calculate the rating of capacitor bank CBs or the step switch CB, the ultimate arrangement for reactive support as per the System Design Sheet needs to be considered. The circuit breaker manufacturer is to be consulted to determine the capacitor bank/step switch rating in consideration of Harmonics, voltage tolerance and back-to-back switching. Further information can be obtained from AS 62271.100 and IEC 56. Jemena prefers type Class C2 circuit breakers for capacitor bank switching as per Clause 3.4.115 of AS 62271.100, however pricing shall also be submitted to Services & Projects for type Class C3.2 circuit breakers. Note: The Capacitor Banks will be operating with floating neutrals.
- One 22kV spare feeder circuit breaker.
- One 22kV spare transformer circuit breaker.
- Spare bus and feeder CT's.
- The circuit breakers shall consist of modern vacuum type interrupters.
- Humidistats used to control the heater operation shall be separated from any adjacent equipment.

1.4. CABLES

Installation and termination of the No.1, No.2 transformer 22kV cables (minimum of 2x 1/c 630mm^2 Cu XLPE per phase to their respective circuit breakers to achieve 1,250A minimum cyclic rating).

The works will also include:

- Cutting over the existing feeders, transformer cables and the No.1 capacitor bank to the new switchboard.
- Installation and termination of HV and LV power cables.

- Distribution feeders shall be relabelled in accordance with the nomenclature convention for zone substations.

1.5. 22KV EQUIPMENT IN GENERAL

- Replace No.1 and 2 transformer 22kV neutral direct ground isolators.
- Replace No.1 and 2 transformer 22kV NER isolators.
- Replace the existing No.2 capacitor bank with a 6MVAr Modular capacitor bank (cubicle type) expandable to 12 MVAr. This new capacitor bank will be installed outdoors to enable the installation of IEC 61850 (smart substation) secondary equipment on the first floor. No.2 bank shall have the neutral solid connection removed (including cable, if possible). The Cap Bank neutral points shall be left to float and a Cap Bank neutral earth switches installed.

1.6. EARTHING

Augmentation of the existing earthing:

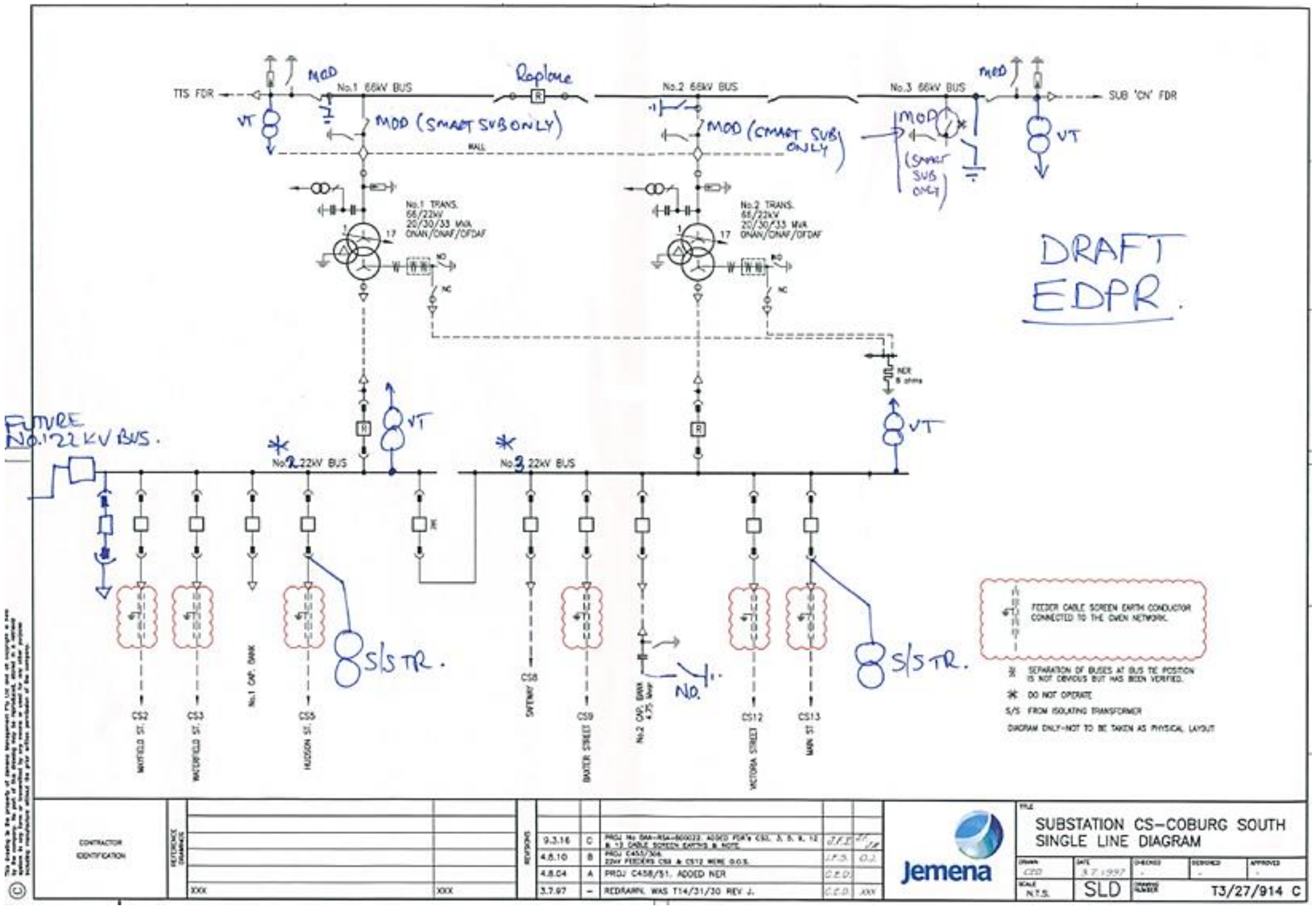
- CMEN bonding of feeder cable screens in accordance with standards.
- Upgrade 66kV and 22kV earthing receptacles and station portable earths.
- Spherical fixed points made of copper aluminium bronze shall be installed to replace standard SECV earthing receptacles. The old earths are to be retained by the HV Operators team, to be assessed and reused at appropriate zone substations in accordance with equipment fault ratings

1.7. STATION SUPPLY

Two 22kV/415V 100kVA pad mount station service transformers connected to:

- No.2 22kV bus.
- No.3 22kV bus.

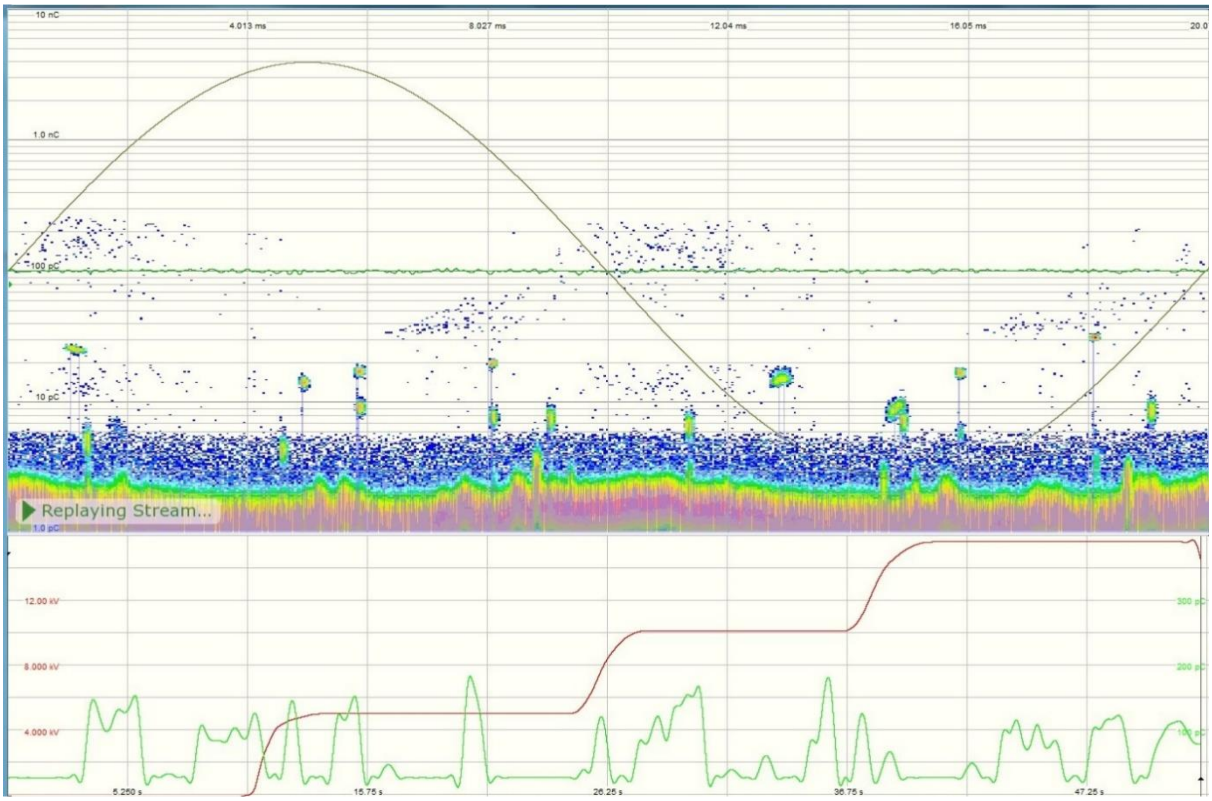
A2. SINGLE LINE DIAGRAM



Appendix B
PD Measurement Graphs

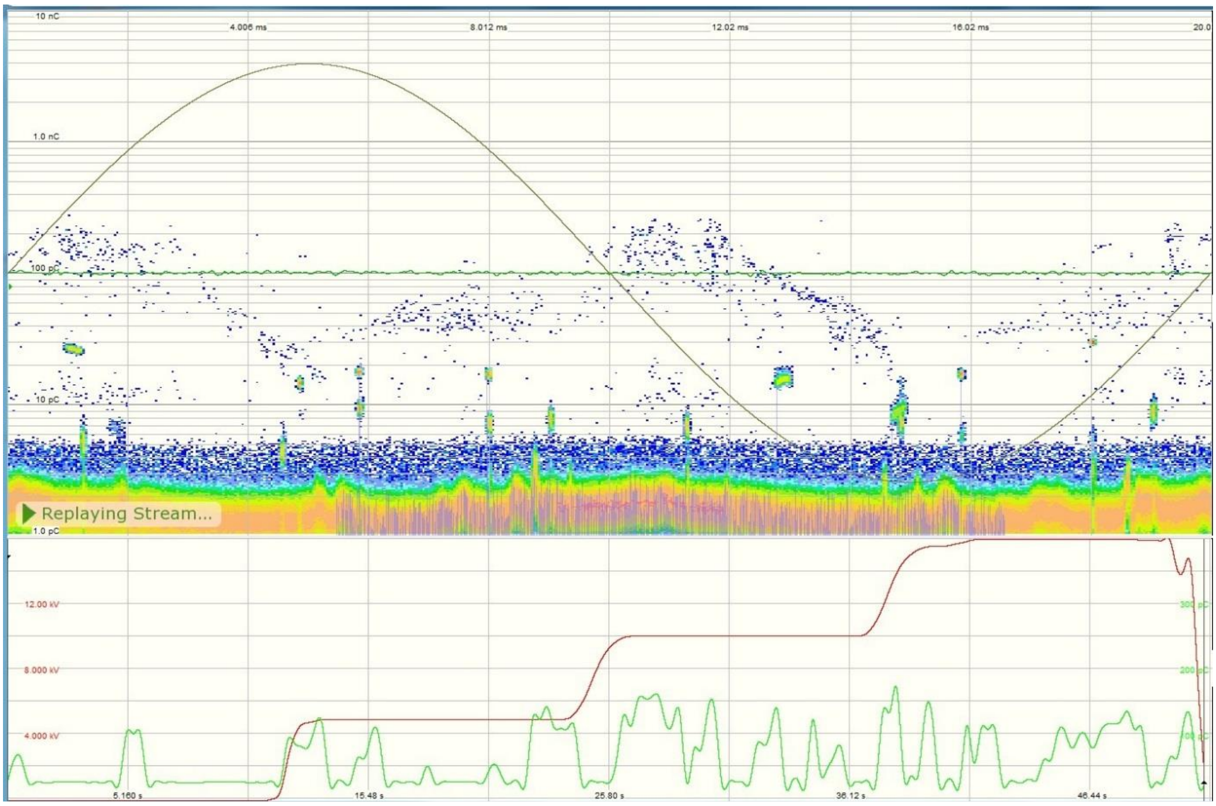
B1. PD GRAPHS

No.1 22kV Bus Red Phase Partial Discharge measurements

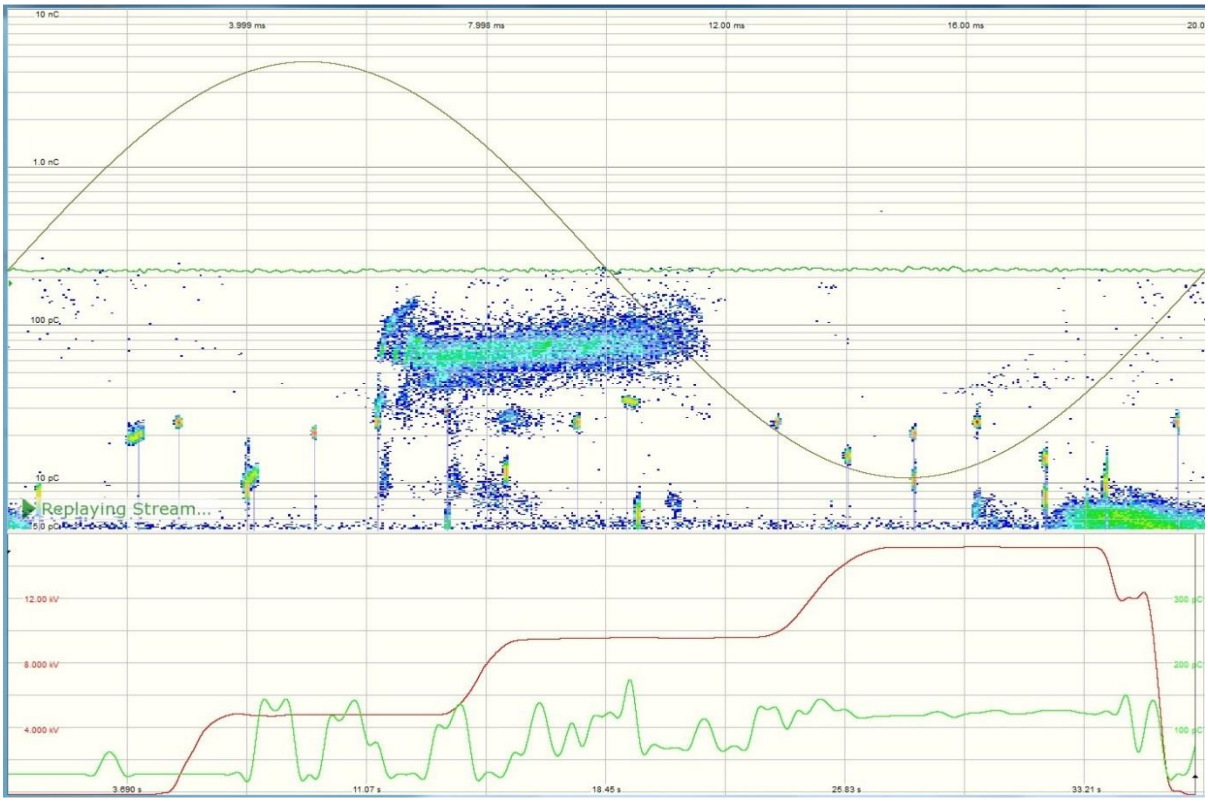


No.1 22kV Bus White Phase Partial Discharge measurements

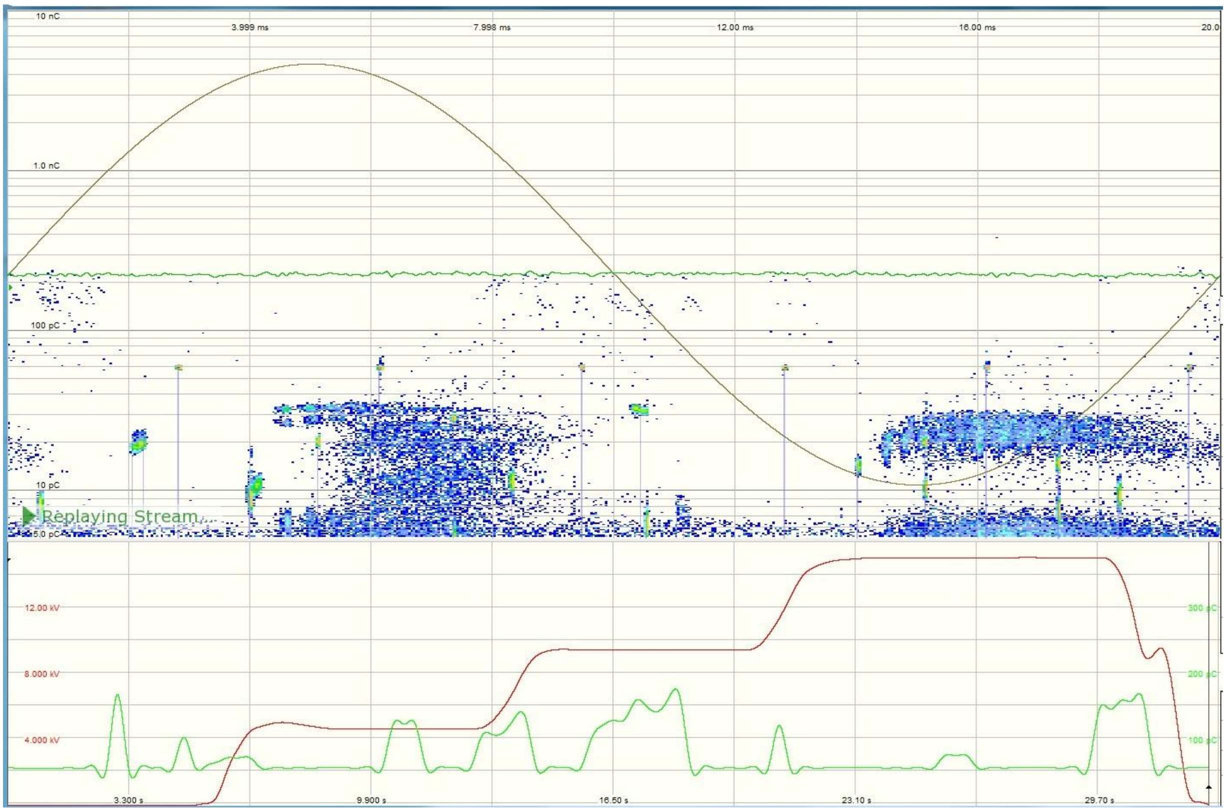
No.1 22kV Bus Blue Phase Partial Discharge measurements



No.2 22kV Bus Red Phase Partial Discharge measurements



No.2 22kV Bus White Phase Partial Discharge measurements



No.2 22kV Bus Blue Phase Partial Discharge measurements