Jemena Electricity Networks (Vic) Ltd

JEN - RIN - Support - NH ZSS Redevelopment Business Case - 20250131

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1. Executive Summary

Synopsis

- The primary and secondary equipment at Zone Substation North Heidelberg (NH) is at risk of failure due to its age and poor condition. This situation raises significant safety and security of supply concerns.
- To manage these risks, five options were considered. The recommended option is to redevelop the zone substation by installing current Jemena Electricity Network (JEN) standardised equipment to replace at-risk assets. Key items for replacement include:
  - Two 66kV circuit breakers
  - Three modular 22kV switchboards
  - An earth fault management system
  - New protection and control equipment
- The project is proposed for completion in 2032 with an estimated total capital expenditure of $35.8 million (Real 2024) with a positive NPV.

1.1 Business need

Zone Substation North Heidelberg (NH) is an indoor zone substation supplying approximately 16,000 JEN customers and is comprised of:

- Three 66/22kV power transformers
- Two 66kV circuit breakers
- Two capacitor banks
- Ten 22kV feeders

The 22kV switchgear, 66kV circuit breaker and all protection and control schemes have reached their end of life. This equipment also poses material risks to employee safety and reliability and security of customer supply. These assets require replacement with modern equivalents providing improved electrical and safety performance in accordance with JEN asset class strategies.

In addition, an earth fault management system is proposed to achieve current public safety, and network supply quality and reliability requirements.

The following issues associated with NH assets are described below in Table 1-1. Refer to Section 2 for a detailed overview of NH assets, associated faults and degree of alignment to JEN Primary Plant and Secondary Asset Class Strategies.

Table 1-1: Current Issues with NH Assets

Issue No.	Description of Issue
1	The current 1-2 66kV bus tie Circuit Breaker (CB) is a type with a history of mechanical failure and catastrophic bushing failures. This CB type (LG4C) is also no longer supported by any manufacturer with spares unavailable.

Issue No.	Description of Issue
2	All transformer high voltage (HV) bushings have been identified for replacement due to type with historic failures and catastrophic consequences of failure (risk of fires destroying the total transformer for example). Bushing Replacement also requires HV Current Transformer (CT) replacement, affecting the turrets and transformers and requiring extensive testing before returning to service.
3	The average age across the installed JEN Disconnectors/Buses sub-asset class is >35 years. Issues with deteriorated insulators and sticky disconnectors have been identified requiring heightened condition monitoring of this sub-asset class. Additionally, wall bushings and the 66kV insulators are at end of life and require replacement in conjunction with switchgear related works
4	Three indoor 22kV metal clad buses and associated circuit breakers manufactured by Sprecher and Schuh type HPTw306-FS are around 50 years old and their condition has degraded where reliability, employee safety and security of customer supply is affected. The switchgear is non-compliant with current standards and partial discharge is occurring on the 22kV buses. The switchgear is no longer supported by any manufacturer with no spare parts available.
5	The capacitor banks are around 50 years old and at end of its design life, increasing the risk of failure in service.
6	Most protection relays are legacy electromechanical relays and do not have real time monitoring. These relays are used to protect major primary plants. The electro-mechanical relays at NH are 50 years old, with a design life of 40 years. Without monitoring, failure of these relays can remain undetected, exposing the network to reliability and safety risks. Additionally, Analogue Electronic and Digital relays at NH are also nearing their design life.

The following options addressing these issues have been considered:

1. **Do nothing**
2. **Increased maintenance and monitoring.**
3. **Redevelop the zone substation.**
4. **Staged replacement of assets**
5. **Non-network solution**

As per the Risk Assessment at Appendix B, the untreated risk ratings are High or Significant for the risks identified. This business case forms the rationale to initiate a project addressing the issues and risks associated with network assets at NH.

1.2 Recommendation

At 50 years old, the 22kV bus, 22kV switchgear and 66kV bus tie circuit breakers have reached or exceeded their design life, as evidenced in Section 2 and the CBRM health index. Their condition has degraded to a point where safety, reliability and security of customer supply are compromised. Additionally, the secondary equipment at the zone substation is at end-of-life, further increasing the risk of failures. Consequently, the replacement of both primary and secondary equipment is recommended as a prudent and efficient investment.

After consideration of all alternatives, it is recommended to adopt Option 3 (Redevelop the zone substation, explained in detail in Section 3.3). This involves replacing all 66kV and 22kV equipment, including all secondary equipment, with modern equivalents that meet current JEN standards. The new equipment will also conform to current Australian and industry standards and be based on a modular concept that utilises Gas Insulated Switchgear (GIS), mitigating safety concerns and improving the reliability and security of customer supply concerns. Implementation of modular equipment also ensures that cost efficiencies are realised by incorporating design elements that reduce the amount of work required to carry out any construction, commissioning or operational activity with the equipment.

This option is recommended because it addresses all identified condition issues whilst minimising the risk to network performance.

The total cost of this option is $35.8M (outlined in Table 1-2) and has a positive Net Present Value (NPV) of $67.9M[1] (outlined in Table 1-4). This preferred solution is proposed to commence in 2029 with commissioning in 2032.

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 NH given their current asset condition.

Three options were explored in the options analysis outlined in Section 3.3 of this document to identify a recommendation. The options have been benchmarked against the risk assessment in Appendix B to ensure that health, safety and reliability issues are addressed. Risk, cost and economic value remain primary drivers.

JEN's investment decisions are ultimately guided by the National Electricity Objective (NEO). Additionally, JEN is required to meet the requirements of the National Electricity Rules (NER), Victorian Electricity Distribution Code of Practice (EDCoP), and public and industry expectations for distribution system performance, which require capital expenditure objectives to be achieved as discussed and outlined in Section 2.3.2.

In preparing this business case, JEN have considered and closely followed relevant AER assessment guidelines. This includes, but is not limited to, the Better Resets Guideline and Expenditure Forecast Assessment Guideline.[2]

1.4 Customer considerations

In addition to regulatory considerations, the expectation from our customers is to implement the most appropriate option that addresses all asset condition issues whilst maintaining customer supply reliability in the most efficient way.

The scope of the asset replacement options include the use of modular equipment. As outlined in section 3.3, the modular approach meets customer requirements by:

- Specifying and designing equipment based on a building block approach
- Selecting equipment available from a wide range of manufacturers
- Installing equipment which can be applied for a variety of configurations
- Installing equipment that can be easily repaired or replaced reducing outage time
- Reducing customised solutions and procedures applicable throughout the project and during the life of the asset

In preparing options for this business case, JEN have considered established philosophies and practices in zone substation asset replacements.

1 Refer to North Heidelberg (NH) Redevelopment Costs and Benefits Analysis Model.xlsb for detailed calculations.

2 In Appendix A of Attachment JEN 0 Att 05-01 Capital expenditure, we have also set out how our proposed capital expenditure, which includes the North Heidelberg Redevelopment, is compliant with the requirements of the NER.

1.5 Economic evaluation and project cost

1.5.1 Forecast expenditure and budget summary

This business case proposes a total capital investment of $35.8M. Further detail of the total capital investment can be found in Appendix B.

This project is required to be commissioned in 2032. Table 1-2 provides the project budget by financial year.

Table 1-2: Project Budget by Year, $2024[3]

Year	Budget ($M)
FY30	4.5
FY31	11.3
FY32	20.0
Total Budget	**35.8**

Please note that the project is proposed to occur within two Electricity Distribution Price Reset (EDPR) periods. The forecast expenditure by EDPR period is captured in

Table 1-3 Project Budget by EDPR Period, $2024

EDPR Period Budget	($M)
EDPR 2027-2031	15.8
EDPR 2031-2035	20.0
Total Budget	35.9

Results of the economic evaluation for the preferred option is provided below and in Table 1-4**Error! Reference source not found.**.

Table 1-4: Financial Analysis Results Summary, $2024[4]

Recommended option	($M)
Total Project Cost (capital):	35.8
NPV of Net Financial Benefit	67.9

3 Refer to North Heidelberg (NH) Redevelopment Costs and Benefits Analysis Model.xlsb for detailed calculations.

4 ibid.

2. Background

This document outlines the business case for the North Heidelberg (NH) zone substation redevelopment, including its alignment with the JEN Primary Plant and Secondary Asset Class Strategies and how our customers will benefit from the project over the long term.[5]

NH consists of:

- Three 66/22kV 20/30 MVA rated power transformers.
- Two 66kV circuit breakers.
- Three 22kV switchboards involving three buses and ten circuit breakers.

Most protection relays are legacy electromechanical types without real-time monitoring, protecting major primary plants such as power transformers and 66kV and 22kV Buses. These relays, over 50 years old, have exceeded their 40-year design life, posing network reliability and safety risks.

Figure 2-1 North Heidelberg Zone Substation Layout

[5] Refer to JEN Primary Plant (ELE-999-PA-IN-008) and Secondary (ELE-999-PA-IN-010) Asset Class Strategies.

Asset Details

<u>66kV switchgear</u>

The NH 66kV switchgear installed at NH is described in Table 2-1 and Figure 2-2.

Table 2-1: NH 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	1,200 A	65-66/199	1966
2-3 66kV Bus Tie CB	Siemens	3AP1-DT	66kV	3,150 A	-	2005

Figure 2-2: NH 1-2 66kV Bus Tie CB

No recorded defects have been found on the NH 1-2 66kV bus tie circuit breaker. However, 66kV bus tie circuit breakers of this type and age have a history of defects leading to catastrophic failure.

<u>22kV switchgear</u>

The 22kV switchgear installed at NH is described in Table 2-2 and Figure 2-3. The Sprecher & Schuh CBs are minimum oil type CBs where the total oil volumes held within each CB pole is small enough that a loss of just one litre of oil can result in catastrophic failure. Additionally, the S&S HPTW306-FS CBs are also installed at zone substations FW (Footscray West) and CS (Coburg South).

Table 2-2: NH switchgear Details

Designation	Make	Type	Voltage	Current	SECV Spec No.	Year of Manufacture
No.1 Transformer, No.2 Transformer, No.1-2 Bus Tie, No.2-3 Bus Tie	Sprecher & Schuh	HPTW306-FS	22kV	1,200A	70/284	1976
FDR NH 2, 3, 5, 8, 9, 12, 13, 16, 17, 20	Sprecher & Schuh	HPTW306-FS	22kV	400A	70/284	1976
No.3 Transformer	Siemens	3AH	22kV	1,200A	-	2004
FDR NH 16, 17, 20	Siemens	3AH	22kV	630A	-	2004

Figure 2-3: NH No.1 22kV Switchgear

There have been 26 recorded defects associated with this NH 22kV switchgear. In addition, 22 defects have also occurred at zone substation Coburg South (CS) which has the same switchgear.

The Sprecher & Schuh HPTW306 22kV CBs are leaking from “O” ring seals on the drive shafts, identified during a routine audit in 2013. A program was initiated to monitor oil levels and replace all “O” ring seals by 2014.

In 2016 partial discharge (PD) was detected on switchboards at CS and NH during routine PD testing. An inspection was carried showing visible PD damage on 22kV busbars and standoff insulators. The switchboards had non-OEM (Original Equipment Manufacturer) modifications at installation. These modifications included PVC conduit covers over bus bars and additional plastic barrier boards to shield LV CT from the HV busbar connections. In the absence of design documentation from the non-OEM modifications, options for rectification are limited.

The presence of PD and oil leaks are the most serious defect on the Sprecher & Schuh switchgear as they increase the potential for catastrophic failure. Maintenance does not always rectify or prevent failures occurring.

Transformers

The transformers at NH are described in Table 2-3. The No.1 and No.2 transformers are oil forced non directional natural cooled transformers whereas the No.3 transformer is an oil forced directional fan forced cooled transformer. The 66kV bushings of all transformers at NH are considered defective due to an inherent design issue that is prone to moisture ingress. Insulation deterioration caused by moisture ingress can lead to a catastrophic failure of the transformer. To rectify any defects, the bushings need to be replaced however there are access constraints given the transformers are installed within a building as shown in Figure 2-4.

Table 2-3 Transformer Details

Designation	Make	Voltage Ratio	NER Installed	Capacity	SECV Spec No.	Year of Manufacture
No.1 Transformer	Tyree	66/22kV	Y	20/30MVA	68/227	1973
No.2 Transformer	Tyree	66/22kV	Y	20/30MVA	68/227	1973
No.3 Transformer	Wilson	66/22kV	Y	20/33MVA	-	2005

Figure 2-4 No. 2 Transformer

2.1 Consumer engagement

2.1.1 Overview of consumer sentiment and relationship to this business case

NH was commissioned in 1973 and is located 13km to the North East of the Melbourne CBD on McNamara St, Macleod. The zone substation is located near Macleod Railway Station and supplies customers in the Yallambie, Viewbank, Macleod, Rosanna, Heidelberg Heights and Heidelberg West areas.

Following an extensive customer engagement program[6] with residential customers, small and medium businesses and large commercial customers located within the JEN Network, we received strong feedback that customers want to ensure our assets are maintained and upgraded to ensure a safe, and reliable electricity network. In terms of our overarching customer engagement program, customer feedback on the Draft Plan highlighted that our consumer engagement has met or exceeded expectations.[7]

Over 150 residential customers from across North-Western Melbourne, including customers from Viewbank, Macleod and Heidelberg Heights, provided feedback on how we can prepare our network for a more sustainable energy future while meeting customer and community needs today. When asked for feedback on the pace and scale of investment we should make on network assets, they told us to strengthen the network to ensure our assets don't compromise the reliability of the network.[8]

This feedback also highlighted the importance of exploring non-augmentation and non-network solutions, which was subsequently explored in this business case. Feedback recommended:

- Exploring non-augmentation solutions such as local energy systems (e.g., batteries, substation improvements) to enhance reliability and resilience.
- Evaluating the trade-offs between cost and benefits to achieve desired reliability levels.
- Considering solutions beyond current regulatory frameworks, like community batteries or aggregator models.

In addition, surveying 1,000 residential customers across JEN's electricity network, reliability and the maintenance of the network was the most important priority to customers. Customers surveyed identified network reliability, defined as 'the ability of the electricity network to perform its function adequately for the period of time intended' as of high importance (97 per cent of surveyed customers placed important on this issue).

This business case for the North Heidelberg zone substation redevelopment intends to give effect to the consumer preference for network reliability and safety.

2.1.2 Jemena's People Panel

The People's Panel, a Citizen's Jury made of up to 50 residential customers, also provided a recommendation for JEN to focus on network reliability, "Jemena needs to prioritise investing in reliability by assessing, building and maintain the network to meet changes in operating conditions and withstand network failures."

The People's Panel rationale for this recommendation was that it is important to invest in network infrastructure with a focus on:

- Improving and maintaining service standards and customer experience
- Reduced frequency in power outages

[6] Refer to Attachments JEN – Att 02-01 – Engagement Strategy – 20230601 – Public; JEN – Mosaic Lab Att 02-22 – Customer deep Dive outcomes report – 20241209 – Public; JEN – Sagacity Research Att 02-08 Customer priorities research report – 20241308 – Public.

[7] Refer to Attachment JEN – Att 02-18 Draft Plan Feedback Report - 20240924.

[8] Refer to Attachment JEN – Att 02-23 Energy Reference Group Report - 20240312.

- Continue to invest in upgrading the network's ability to "self-heal"
- Flexibility to accommodate network growth and demand

For context, the People's Panel is an iterative consultation mechanism which was formed to represent customers from across JEN's network and to help us understand how we can prepare for a sustainable energy future, while meeting customer and community needs today. The People's Panel is a diverse selection of JEN's customers, incorporating all walks of life - cultural diversity, age, gender and geographic location. For reference, the People's Panel spent five Saturdays together over six months, learning about the role we play in the electricity supply network.

2.1.3 AER expectations for consumer engagement

Better Resets Handbook		Alignment to this business case
Nature of engagement	Sincerity of engagement	• We engaged with customers through multiple channels, allowing diverse opinions and recommendations for JEN investment priorities. • Independent facilitators and researchers, such as MosaicLab and Sagacity Research were utilised.
	Consumers as partners	• We partnered with consumers directly through our People's Panel. Recommendations from this panel explicitly recognised the need for network reliability.
	Equipping customers	• Engagement materials briefed customers on key concepts, including (but not limited to) how the electricity supply chain works, an overview of JEN's operating environment, megatrends in the energy market, the regulatory context, and a snapshot of our customer base.
	Accountability	• Independent facilitators and researchers, such as MosaicLab and Sagacity Research were utilised.
Breadth and depth of engagement	Accessible, clear and transparent engagement	• We engaged with customers through multiple channels, allowing diverse opinions and recommendations for JEN investment priorities. • Engagement materials briefed customers on key concepts, including (but not limited to) how the electricity supply chain works, an overview of JEN's operating environment, megatrends in the energy market, the regulatory context, and a snapshot of our customer base.
	Multiple channels of engagement	• We engaged with customers through multiple channels, allowing diverse opinions and recommendations for JEN investment. This included through direct feedback, consumer surveys, and our People's Panel. • Our full regulatory proposal outlines our consumer engagement program and initiatives in detail.
	Consumers influence on the business case	• Engagement highlighted the importance of prioritise investing in reliability by assessing, building, and maintaining the network to meet changes in operating conditions and withstand network failures

Clearly evidenced impact	Business case linked to consumer preferences	• This business case for zone substation redevelopment at North Heidelberg specifically supports the consumer preference for network reliability – given the risks and consequences of undertaking non-preferred options.
	Independent consumer support from the business case	• The independent Sagacity Research report concludes that: *When ranked, network reliability comes to the fore, followed by network resilience*

The alignment of our consumer engagement program with AER expectations has been detailed further in our broader regulatory proposal.

2.2 Asset risk (or opportunity) analysis

2.2.1 Short description of the affected assets

Issues associated with the assets have been identified and are discussed below.

66kV Equipment

Switchgear 1-2 66kV Bus Tie CB (Type LG4C)

This family of breakers has a history of failure, including catastrophic insulation failure, impacting employee safety and security of customer supply. Notable incidents include:

- 2015: Bushing failure on the 1-2 66kV bus tile CB at ZSS FE due to insulation degradation
- 2023: Bushing failure at Brooklyn Terminal Station on the 2-3 66kV bus tie
- CB controls are rated for 240V DC, but are required to operate at 110V DC to align with the standard secondary systems DC system discussed in the JEN Secondary plant asset class strategy.[9]

Cables

Existing subtransmission cables are oil filled and around 50 years old. This presents a risk due to the limited availability of skilled maintenance personnel, which impacts response and repair times for faults and leaks.

22kV Equipment

Switchgear

The two Sprecher and Schuh (HPTw306-FS) indoor 22kV metal clad buses and associated minimum oil circuit breakers are around 50 years old. Their condition has deteriorated effecting employee safety, equipment reliability and security of customer supply. Specific issues include:

- **Non-Compliant**: Switchgear is non-compliant with current electrical arc fault containment standards, with electrical arc and pressure waves potentially not contained within the switchgear. Arc flash is a serious hazard that has the potential to cause death, serious injury, loss of electrical supply and damage to equipment. Currently increased administrative controls are in place when operation and maintenance activities are conducted on this equipment to safely protect workers. With an increase in these activities due to asset condition, workers are continuously being exposed to these risks. Replacing the switchgear with modern standardised equipment is the most effective form of control to mitigate arc flash risk given new equipment has superior engineering control measures implemented into the design.

[9] Refer to JEN Secondary Plant (ELE-999-PA-IN-010) Asset Class Strategy.

- **Partial Discharge**: PD was detected on the 22kV switchboard, revealing visible PD damage on the busbars and standoff insulators. This damage cannot be reversed and will continue to degrade the insulation until catastrophic failure.
- **Oil leaks**: Leaks found on the CBs can only be monitored whilst the CB is racked out, leading to additional network operational requirements and expenditure. Condition checks require outages on each CB inspected reducing serviceability. New standardised CBs are vacuum insulated CBs and do not require outages or field crew to monitor it's insulating medium. Modern air insulated switchgear requires less maintenance than oil insulated switchgear with advances in design resulting in reduced safety risks when operation and maintenance activities are conducted.

- **Obsolete:** The 22kV switchboard is obsolete with insufficient spares. It is no longer supported by the manufacturer increasing the risk of catastrophic failure with extended outage time to overcome.

<u>Capacitor Bank</u>

The capacitor bank is nearly 50 years old, with deteriorating interior insulation of capacitor cans and the external enclosure., and the CB at the end of its design life.

Transformers

The No.1 and 2 Transformer HV bushings are SECV I1079 type, over 50 years old and are a synthetic resin bonded paper (SRBP) oil to air condenser bushing. Issues include:

- **Defective bushings**: The No.3 transformer HV bushings are an Oil Impregnated Paper (OIP) type which are considered defective due to an inherent design issue that has been highlighted by a manufacturer investigation. All HV transformer bushings are NH are prone to moisture ingress and have been targeted for replacement.

- **Replacement**: Replacement of the indoor zone substation transformer bushings will require careful planning with extensive testing required to return the transformer to service.

Protection and Control Equipment

There have been 34 recorded defects since 2011 associated with Protection, Control, Supervisory Control and Data Acquisition (SCADA) and Communications equipment at NH. The defects are occurring at an average of 2.7 per year. The cause of these defects predominantly relates to the age and condition of the equipment.

<u>Relays</u>

Many of the protection relays are legacy electromechanical relays that do not have real-time monitoring features. These relays protect major primary plants, including power transformers, 66kV and 22kV Buses, and 22kV feeders. Failure of these relays may remain undetected, exposing the network to reliability and safety risks.

The analogue electronic and digital relays at NH are also at the end of the design life with increasing risk of failure.

<u>DC system</u>

Batteries and chargers are a critical system nearing the end of their design life. Failure of the DC system leaves the zone substation unprotected posing serious safety, asset and loss of supply risk.

<u>SCADA and Communications</u>

Specific issues include:

- **SCD5200 RTU**: This RTU has been in service for over 20 years, and is well beyond its design life, requiring an increased maintenance regime to manage failure risk. The current RTU cannot facilitate Digital Substation portfolio objectives and requires replacement with compatible equipment to incorporate the required functionality.

Communications System: This legacy system doesn't have the ability to achieve the modern functionality required by the JEN Secondary System Asset Class Strategies.

2.2.2 Risk assessment

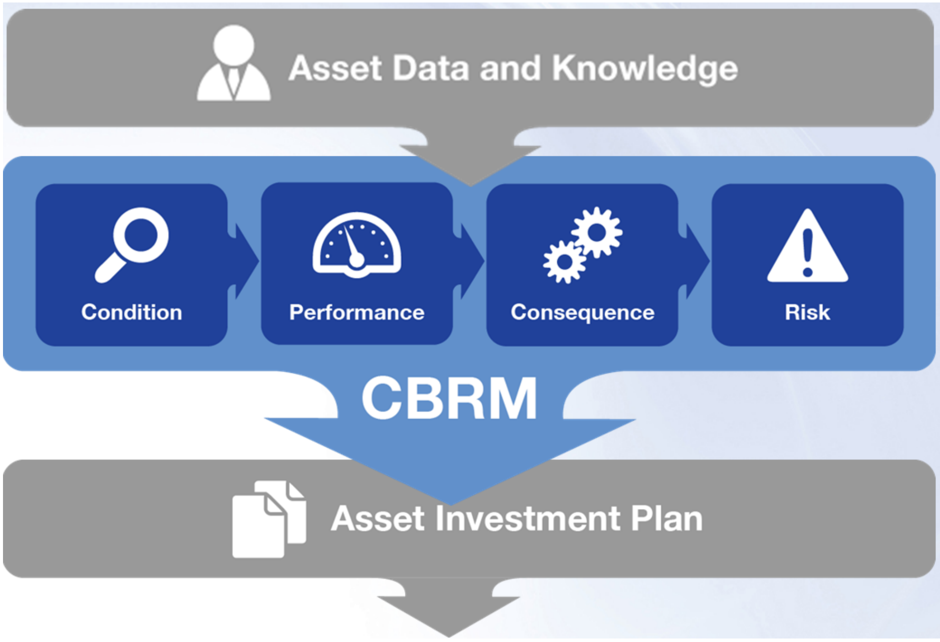
A network asset risk assessment has been completed for assets installed at NH. The risk assessment results have highlighted that the current condition of assets and controls implemented exceed JEN risk appetite and require further treatment. The current condition of assets at NH are driving key safety and business continuity risks. Further details of the network assets risk assessment are shown in Appendix B.

Primary Equipment

JEN applies Condition Based Risk Management (CBRM) modelling for switchgear and transformer assets to assist in developing asset investment plans using existing asset data and other information. A detailed description of the CBRM model works and CBRM model results for zone substation-related assets can be found in the Guideline - Condition Based Risk Management (CBRM)[10].

The CBRM model is a structured process that combines asset information, engineering knowledge and practical experience to define future condition, performance and risk for network assets. An overview of the CBRM asset management process is outlined in Figure 2-5.

Figure 2-5 Overview of CBRM Asset Management Process



The CBRM model process can be summarised by a series of sequential steps as follows:

1. **Define asset condition.** 'Heath indices' for individual assets are derived and built for different asset groups. Current health indices are measured on a scale beginning from 0 to greater than 7, where 0 indicates the best condition and values above 7 the worst.

2. **Link current condition to performance.** Health indices are calibrated against relative probability of failure (**PoF**). The health index/PoF relationship for an asset group is determined by matching the health index profile with the recent failure rate.

3. **Estimate future condition and performance.** Knowledge of degradation processes are used to 'age' health indices. The ageing rate for an individual asset is dependent on its initial health index and

[10] Refer to ELE GU 0005 Guideline - Condition Based Risk Management (CBRM).

operating conditions such as high pollution areas and distance to coastal environments. Future failure rates can then be calculated from aged health index profiles and the previously defined health index/PoF relationship.

4. **Evaluate potential interventions in terms of PoF and failure rates.** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled and the future health index profiles and failure rates modified accordingly.

5. **Define and weight consequences of failure (CoF).** A consistent framework is defined and populated in order to evaluate consequences in significant categories such as network performance, safety, financial and environmental. The consequence categories are weighted to relate them to a common monetary ($) unit.

6. **Build risk model.** For an individual asset, its probability and consequences of failure are combined to quantify risk. The total risk associated with an asset group is then calculated as the sum of the risk of the individual assets.

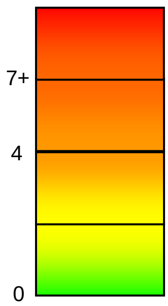
7. **Evaluate potential interventions in terms of risk.** The effect of potential replacement, refurbishment or changes to maintenance regimes can then be modelled to quantify the potential risk reduction associated with different strategies.

8. **Review and refine information and process.** Building and managing a risk-based process on the basis of asset specific information is not a one-off process. The initial application will deliver results based on available information and, crucially, identify opportunities for ongoing improvement that can be used to progressively build an improved asset information framework.

The key element of the CBRM model is the Health Index which it outputs for each asset which corresponds to a scale representative of the assets condition, remnant life and probability of failure. As noted above, Health index values begin at zero and can be greater than seven. Values greater than seven represent serious deterioration and the need to plan for replacement before failure occurs. The health index is described in Table 2-4.

Table 2-4 Asset Health Index

Condition	Health Index	Remnant Life	Probability of Failure
Bad		At EOL (<5 years)	High
Poor		5 - 10 years	Medium
Fair		10 - 20 years	Low
Good		>20 years	Very low



The CBRM modelling results are summarised in Table 2-5. The results indicate the CBs are in a severely deteriorated condition. By 2031, the CBRM health index indicates a high probability of failure should no action be taken.

Table 2-5 Primary Equipment CBRM

	2024		2031	
Primary Equipment	**Average**	**Maximum**	**Average**	**Maximum**
66kV Bus Tie CB	4.65	7.81	5.99	9.89
22kV CBs	7.01	9.21	9.03	11.82

If these assets were to fail in the next regulatory control period, the failure or maloperation of primary equipment can lead to major consequences, which can be categorised as follows:

- **Health and safety**: Severe damage to HV apparatus and loss of supply (outages), potentially causing extreme HSE incidents to personnel, the community or environment
- **Operational**: Limits business operations of the distribution network, enforcing contingency plans due to the loss of supply (outages)
- **Financial**: Loss of supply (outages) can result in financial penalties based on frequency of occurrence, duration and number of customers affected
- **Reputation**: Negative perception from industry and customer stakeholders if reliability and safety performance is reduced
- **Regulatory**: Breaches of obligations under legislation, regulation, rules and codes.

The investment outlined in this business case seeks to address these requirements and risks.

Secondary Equipment

Protection and control systems are designed to detect the presence of faults or other abnormal operating conditions and to automatically isolate the faulted network by opening appropriate high voltage circuit breakers. Interruptions to customers from faulty protection and control equipment are generally caused by either:

- Failure of the protection relay to act upon a genuine fault
- Mal-operation of the protection relay under system normal conditions

The secondary equipment at NH is operating at end-of-life with increasing risk of asset failure. Like the primary equipment, all risks for secondary equipment are identified and managed in Omnia which is Jemena's Risk and Compliance Management System. Failure or maloperation of protection relays lead to the same 'Major' consequences previously described.

The investment outlined in this business case seeks to address these requirements and risks.

2.3 Project objectives and assessment criteria

2.3.1 Project objective

In line with the NEO, JEN's investment decisions aim to maximise the net present value to electricity consumers. The objective of this project is to maintain the reliability of supply to customers given the current condition of the assets. This strategy must align with other JEN strategies and plans and the project must comply with associated regulatory requirements.

2.3.2 Regulatory considerations

JEN's investment decisions are guided by the NEO. Additionally, the capital expenditure objectives set out in the NER (clause 6.5.7) are particularly relevant:

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*
>
> (iv) *Maintain the reliability and security of the distribution system through the supply of standard control services.*
>
> *(4) Maintain the safety of the distribution system through the supply of standard control services.* [11]

Additionally, the Victorian EDCoP sets out provisions relevant to JEN's planning, design, maintenance, and operation of its network, most notably section 19.2 (Good Asset Management) and section 13.3 (Reliability of Supply):

Section 19.2 – 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*
   - *In a way which minimises costs to customers taking into account distribution losses.*

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 13.3 – Reliability of Supply

A distributor must use best endeavours to meet targets determined by the AER in the current distribution determination and targets published under clause 13.2.1 and otherwise meet reasonable customer expectations of reliability of supply.

When making decisions to invest, JEN must comply with these obligations.

2.3.3 AER assessment criteria

In preparing this business case, JEN have considered and closely followed relevant AER assessment guidelines. This includes, but is not limited to, the Better Resets Guideline and Expenditure Forecast Assessment Guideline.[12]

11 NER, cll 6.5.6(a), 6.5.7(a).

12 In Appendix A of Attachment JEN 0 Att 05-01 Capital expenditure, we have also set out how our proposed capital expenditure, which includes the North Heidelberg Redevelopment, is compliant with the requirements of the NER.

2.4 Consistency with strategy and plans

This section describes how this project is consistent with JEN's objectives and strategies:

- **Provision of Service Levels and Reliability**: Ensuring service levels and reliability that meet customer expectations.
- **Modern Capabilities**: Deployment of modern equivalent capabilities in the network to remain relevant to customers in the longer term.
- **Prudent and Efficient Expenditure**: Ensuring expenditure is prudent and efficient, aligning with customer expectations regarding affordability.
- **Optimised Investment Profile**: Driving an investment profile that optimises regulatory allowances and provides expected returns to shareholders.

JEN seeks to ensure that lifecycle costs are both efficient and effective. This business case is consistent with this requirement and aligns with the long-term vision of the network, as set out in the Asset Management Plan (AMP) and annual planning reports.

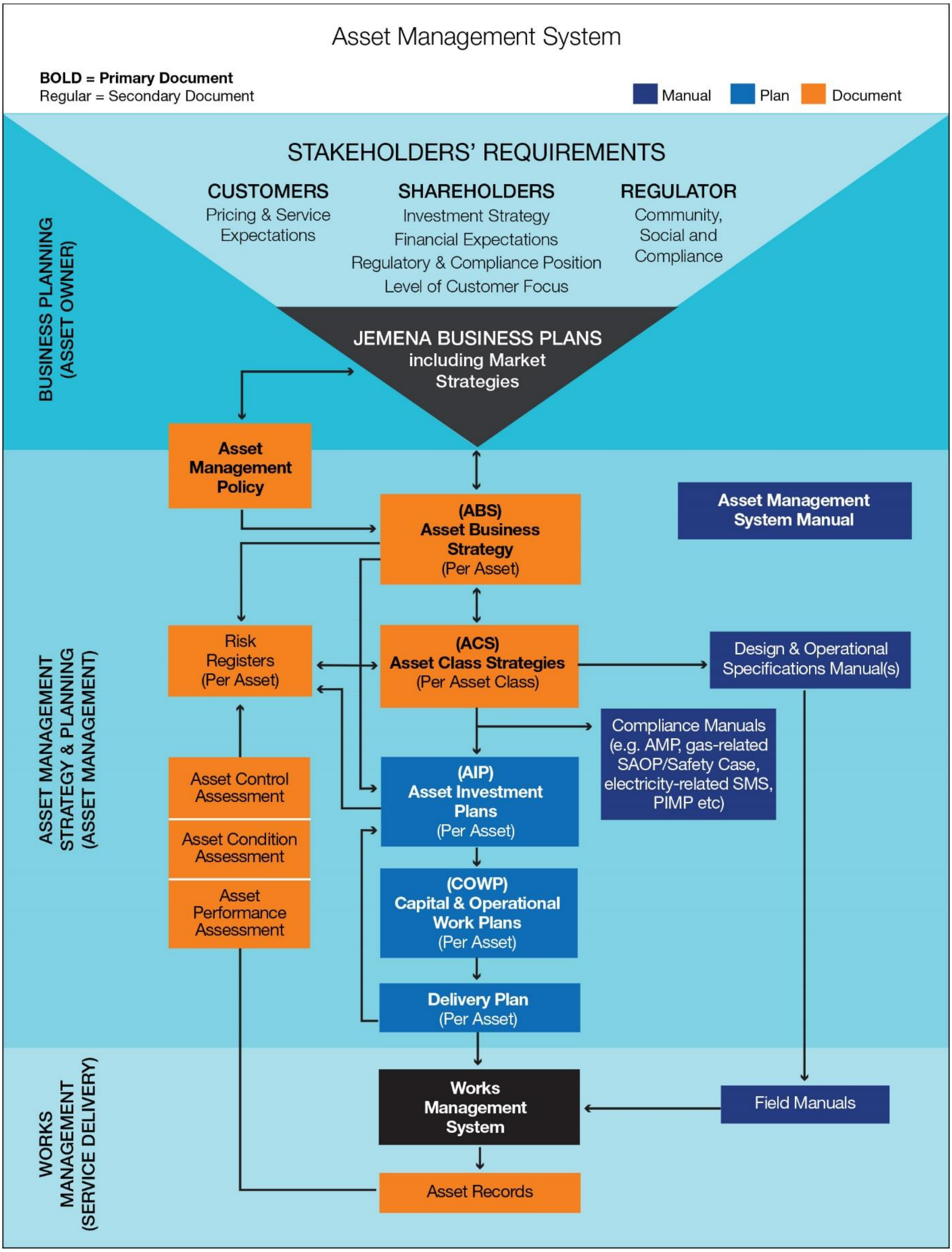
This proposal aligns with Asset Management Strategies, Plans and Policies contributing to a safe workplace for JEN employees and contractors. By addressing identified issues, JEN can reduce the risk of injury to its staff or members of the public.

JEN abides by Australian asset and risk management industry standards (ISO 55001 and ISO 31000:2018) which is part of JEN's internal risk and asset management framework document documents (ELE PL 0004 and JAA PO 0050).

Figure 2 6 outlines the Jemena Asset Management System and shows where the Asset Management Plan (AMP) is positioned within it. The AMP covers the creation, maintenance and disposal of assets, including investment planning to augment network capacity and replace degraded assets to maintain reliability of supply.

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

Figure 2-6: The Jemena Asset Management System



3. Credible Options

3.1 Identifying credible options

The following options were identified to address the business needs, problems or opportunities.

- Option 1 – Do nothing.
- Option 2 – Increased maintenance and monitoring.
- Option 3 – Redevelop the zone substation.
- Option 4 – Staged replacement of assets
- Option 5 – Non-network solution

A preliminary assessment determined that Option 5 would not be considered further and has been excluded the options evaluation and subsequent sections. The key reasons for its exclusion are as follows:

- Most issues highlighted remain unresolved
- The condition of the asset that remains in service will lead to an unacceptable risk profile with heightened consequences
- Increased costs with no ability to realise delivery and operational efficiencies inherent in implementing standardised equipment and JEN asset strategies.

The preliminary assessment of the non-network solution is further described in Appendix C.

3.2 Developing credible options

Table 3-1 shows the extent to which each option addresses the identified issues.

Table 3-1: Options Analysis

Issue	Option 1 Do Nothing	Option 2 Increased maintenance and monitoring	Option 3 Redevelop the zone substation	Option 4 Staged replacement of assets
Issue 1 66kV switchgear condition and obsolescence	○	○	●	◑
Issue 2 66kV Transformer bushing condition	○	○	●	◑
Issue 3 66kV Bus, disconnectors and insulator condition	○	◑	●	◑
Issue 4 22kV switchgear condition, not arc fault rated and obsolescence	○	○	●	●
Issue 5 22kV capacitor bank condition	○	◑	●	◑
Issue 6 Legacy secondary system	○	○	●	◑

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

3.3 Options analysis

3.3.1 Option 1: Do nothing

The ‘do nothing’ option assumes business as usual, continuing current maintenance activities such as inspections, condition monitoring, preventive maintenance and defect repairs. However, this option does not address any of the identified condition issues, particularly the switchgear and transformer. For instance, the 22kV switchgear currently has a CBRM health index average rating of 7.01 indicating that the equipment condition is bad, at end of life (<5 years) and has a high probability of failure now. The probability of failure for this equipment would continue to increase over time, potentially leading to catastrophic failure while in service. Given the criticality of these issues and the lack of risk mitigation, this option is not considered credible.

3.3.2 Option 2: Increased maintenance and monitoring

This option involves closer monitoring of the switchgear and transformers, with a two-fold increase in the frequency of condition testing. Despite this, the ultimate failure of the CBs and transformers cannot be prevented if they remain in-service. The condition of the primary equipment will continue to deteriorate, impacting reliability and safety with anticipation of failure within 5 years as per the CBRM modelling results.[13] Similarly, increasing maintenance and monitoring of secondary systems will not prevent failure or avoid the risk of equipment mal-operation.[14] Additionally, increasing maintenance and monitoring will require taking equipment out of service,

13 Refer to Section 2 for CBRM modelling results.

14 Internal Costs and Benefits Analysis modelling suggests $4.4M in additional incremental costs to increase maintenance and monitoring. Refer to North Heidelberg (NH) Redevelopment Costs and Benefits Analysis Model.xlsb for detailed calculations.

increasing supply reliability risks. Given this option does not resolve majority of the issues described in Table 3-1, this option is not recommended as it is more likely to resemble the 'do nothing' option.

3.3.3 Option 3: Redevelop the zone substation

This option involves decommissioning legacy and deteriorated equipment, and replacing most zone substation equipment with new standardised equipment. This will enable the substation to operate according to JEN Asset Class and Business Strategy documentation. This option addresses all identified issues including safety, reliability and security of customer supply. Major assets to be installed include:

- New 66kV modular GIS equipment: busbars, insulators, circuit breakers, voltage transformers, current transformers, motorised double break disconnectors, earth switches and surge arrestors.
- Three sets of transformer bushings.
- A new earth management system including arc suppression coil (ASC), ASC bypass CB, neutral earthing resistor (NER) and associated secondary systems.
- Two new 22kV/433V station service transformers (kiosk type).
- Three new modular indoor 22kV switchboards consisting of busbars, insulators, circuit breakers, voltage transformers, current transformers, disconnectors, earth switches and surge arrestors.
- Two new 22kV containerised capacitor banks. The Cap Banks shall have floating neutrals with VAr control and neutral earth switch.
- Civil and structural works associated with new or decommissioned equipment including earth grid works.
- New secondary equipment required to complete protection, control, communications and auxiliary supply functions required for the zone substation.

In line with JEN initiatives to provide a safe working, cost effective and efficient asset management of network assets, this option proposes to adopt a modular concept approach for all equipment installed on site. JEN intends to adopt modular equipment for all new asset installations at greenfield and brownfield sites when a significant amount of works are required, or space allows for modular equipment be installed and cutover accordingly i.e. in situ replacements can be avoided.

The principle of the modular concept utilises a building block approach and enables a complex system to be broken up into smaller independent units called modules. In the case of zone substation asset, these key modules take the form of switchgear, buildings and secondary systems. Modular equipment is standardised and incorporates opportunities for improvement during the specification and design phase that reduce construction, commissioning and operating costs. Furthermore, modular equipment is widely available from manufacturers and provides additional benefits in asset flexibility/configurations, reliability, scalability and safety which are essential in ensuring JEN business and customer objectives are met.

Option 3 is the preferred option. This option resolves all identified issues while aligning with the JEN asset class and business strategies and the implementation of modular building concepts that aim to realise benefits in lower construction, commissioning and operational costs. NH is an indoor zone substation and due to space constraints, this option proposes to utilise modular GIS 66kV switchgear. The total cost of this option is $35.8M as outlined in Table 1-2 and has a positive NPV of $67.9M.[15] This preferred solution is proposed to commence in 2029.

[15] Refer to North Heidelberg (NH) Redevelopment Costs and Benefits Analysis Model.xlsb for detailed calculations.

3.3.4 Option 4: Staged replacement of assets

This option involves decommissioning legacy items and deteriorated equipment in a two-staged manner. This will see most of the zone substation equipment eventually replaced with new standardised equipment. This will ultimately enable the substation to operate in accordance with the strategies and philosophies described in JEN Asset Class and Business Strategy documentation. Only at completion of the second stage of replacement works will all issues associated with safety, reliability and security of customer supply be addressed. A staged replacement of major assets to be installed include:

<u>Stage 1: 2026 - 2030</u>

- Three new modular indoor 22kV switchboards: busbars, insulators, circuit breakers, voltage transformers, current transformers, disconnectors, earth switches and surge arrestors.
- Civil and structural works associated with new or decommissioned equipment including earth grid works.

<u>Stage 2: 2031 - 2035</u>

- Three sets of transformer bushings.
- New 66kV modular GIS equipment: busbars, insulators, circuit breakers, voltage transformers, current transformers, motorised double break disconnectors, earth switches and surge arrestors.
- A new earth management system including arc suppression coil (ASC), ASC bypass CB, neutral earthing resistor (NER) and associated secondary systems.
- One new 22kV/433V station service transformer (kiosk type).
- One new 22kV 4.8MVAr containerised capacitor banks with floating neutrals, VAr control, and neutral earth switch. The Cap Bank will have floating neutrals with VAr control and neutral earth switch.
- New secondary equipment required for protection, control, communications and auxiliary supply functions. Secondary works to include relocation of stage 1 secondary works into the vacated cap bank room.
- Civil and structural works associated with new or decommissioned equipment including earth grid works.

The staged replacement approach prioritises the resolution of issues based on the condition and criticality of the assets. The 22kV switchboards are considered a critical asset due to the high replacement costs, impacts on customer supply, long lead time for repair or replacement and occupational health, safety and environmental impacts that can occur from a defect or failure.

The CBRM health index indicates the No.1 and No.2 22kV switchboards are in bad condition and at a high risk of failure (within 5 years) therefore resolving the issues associated with these assets are proposed to be completed in the first stage of works. Whilst replacing the No.1 and No.2 22kV switchboards in the first stage of work fully addresses the transformer issues identified, most of the issues identified remain unresolved until the second and final stage of works are completed. This means a high volume of assets in a bad condition will remain in service between the two stages of asset replacement works. This results in the same level of energy (MWh) at risk until project completion however at a slightly lower probability of occurrence. For these reasons, most of the issues are partially addressed as shown in Table 3-1.

Option 4 will eventually address all issues upon completion of the second stage however is not the preferred option. The consequences described in Section 2.2 remain a risk too great for JEN to leave untreated. The staged asset replacement works does not align with JEN asset class and business strategies with the CBRM health index for most of the assets greater than 7 (indicative failure within 5 years).

The conclusion of this assessment is that replacing the primary plant and secondary assets using a staged approach will result in an estimated increase in total project cost of approximately 20%. This is due to the introduction of the following inefficiencies:

- the new secondary systems would need to be wired to the existing primary plant and then later re-wired to the new primary plant.
- testing and commissioning the new secondary systems and primary plant would need to be performed twice rather than once had all of the assets been replaced at the same time.
- two instances of site mobilisation / demobilisation rather than one which involves site construction facilities, inductions, project management establishment.
- two sets of review of the secondary design drawings and protection settings rather than one.
- twice as many planned outages to be planned, scheduled and switched out.

In addition, mobilising to a site on two occasions and completing the project as a staged approach introduces the following risks:

- Twice as many occurrences of planned outages during construction, testing and commissioning which increases the potential for health and safety incidents.
- Overall duration of the project is increased which increases the disruption duration for customers and to the local community. This would have an impact of increasing local traffic movements, increasing noise, and reducing pedestrian access.
- Potential for the unavailability of personnel and therefore intellectual property associated with the first stage of the project, ultimately leading to re-work and inefficiencies in the second stage.
- Potential changes in technology in the intervening 3-5 year period which would result in some re-work of Stage 1 to make the secondary system compatible with the primary plant.

4. Option Evaluation

4.1 Economic evaluation

In line with the objectives of the National Electricity Rules, JEN augmentation 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, JEN has undertaken a probabilistic cost-benefit assessment of replacement options.[16] JEN undertook this assessment using its Cost and Benefits Analysis Model, This assessment considers the likelihood and severity of critical network outages, evaluating the expected impact of asset failures and subsequent network outages on supply delivery. It combines this with the value that customers place on their supply reliability (VCR)[17] (where the cost of risk = (network performance + capex + opex) x probability), and compares the result with the costs required to reduce the likelihood or impact of these supply outages. The benefits considered in this economic analysis relate to mitigating the increasing risk of failure of the transformers, 22kV circuit breakers and 66kV circuit breaker. This includes the safety risks associated with Option 1 (do nothing) as described in section 3.3.1. The following table summarises the economic analysis undertaken.

Table 4-1: Economic Analysis Results Summary, $2024[18]

($M)	Option 1	Option 2	Option 3	Option 4
Total Expected costs	0	0	35.8	18.9
Total Expected market benefits	0	0	95.9	90.1
Net market benefits	0	0	67.9	57.8
Option ranking	4	3	1	2

4.1.1 Disposals

An assessment has been made on the equipment which will be replaced as part of this project. This equipment has no written-down value due to its age.

16 Refer to North Heidelberg (NH) Redevelopment Costs and Benefits Analysis Model.xlsb for detailed calculations.

17 ibid.

18 ibid.

5. Recommendation

This business case proposes a total capital investment of $35.8M ($2024).

It is recommended that Option 3 be adopted. The scope of works include replacement of the 66kV and all the 22kV equipment and secondary systems with new modern equivalents installed to current standards and philosophies.

This option maximises the net present value to JEN customers and addresses all identified risk and issues, therefore mitigating negative impacts on safety, reliability and security of customer supply.

It is recommended that the project commence in 2029 with completion in 2032.

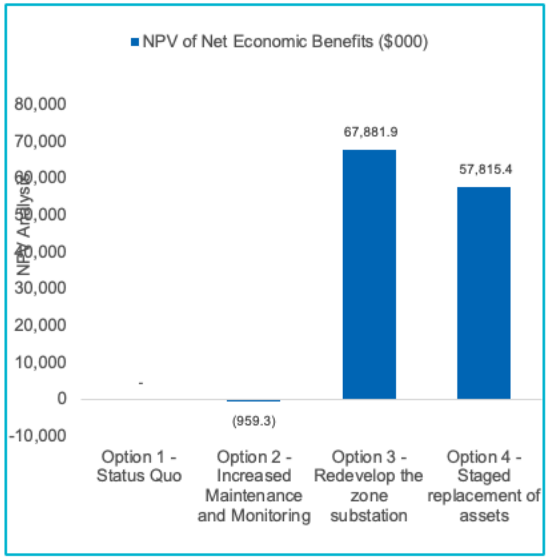
6. Exclusions

There are no exclusions within this business case.

Appendix A
Financial Evaluation Spreadsheets

A1. Financial Evaluation Spreadsheets

Overview of Options Analysis				
Options	**Option 1 - Status Quo**	**Option 2 - Increased Maintenance and Monitoring**	**Option 3 - Redevelop the zone substation**	**Option 4 - Staged replacement of assets**
Recommended Option			✓	
NPV of Net Economic Benefits ($000)	**-**	**(959.3)**	**67,881.9**	**57,815.4**
NPV of Total Economic Benefits ($000)	-	-	95,922.0	90,148.7
Avoided cost at asset failure	-	-	*4,380.5*	*3,195.8*
Improved energy reliability	-	-	*91,541.5*	*86,952.9*
Reduced energy losses	-	-	-	-
Other Economic Benefits	-	-	-	-
NPV of Incremental Total Costs ($000)	-	959.3	28,040.1	32,333.3
Total Incremental Net Capex	-	-	*28,040.1*	*32,333.3*
Total Incremental Opex - One-off	-	-	-	-
Total Incremental Opex - Ongoing	-	*959.3*	-	-
Sensitivity on Economic Benefit NPV ($000)				
Economic Benefits turn out to be 10% lower	-	(959.3)	58,289.7	48,800.5



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Appendix B
Network Risk Assessment Summary

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B1. Network Risk Assessment Summary

Risk Register	North Heidelberg (NH) Redevelopment			
Participants:	Alan Shu, Jignasa Sharma, Kopeeswaran Vaikundan, David Craven, Jon Bernardo		Workshop Date: 6/9/2024	MS Teams

S/No	Business Unit	Business Objective Category	Risk type	Risk Title	Risk Description	Root Causes Category	Root Causes - Description (Contributing Factors)	Risk Consequence Category	Risk Consequence - Description	Risk Owner	Untreated Consequence	Untreated Likelihood	Untreated Risk Rating
1	Jemena Networks - Electricity	Sustainability	Safety risk	Working in the vicinity of live assets	Injury to employees or contractor working near or with equipment inside the zone substation building. Many assets are near end of life with potential for explosive failures of bushings, insulators and tank raptures.	Resources – Assets, Cash, Equipment, Property	**Resources** - Primary Plant due to condition and age (end of life).	Employee	- Injury to employees or contractors working in the vicinity of equipment inside the zone substation building - Regulatory investigations	M Ciavarella	Major	Possible	High

S/No	Current Controls	Control Assessment Frequency	Control Owner	Control Effectiveness
1	Asset Management System (ACS) including Asset Class Strategy.	6-monthly	M Ciavarella	Effective
	VESI Switchgear Manual	6-monthly	M Gardiner	Effective
	The VESI Green Book	6-monthly	M Gardiner	Effective
	Emergency management plan	6-monthly	F Dunk	Effective
	Stakeholder/Customer engagement plan and procedures	6-monthly	J Ng	Effective
	Job Safety Assessments (JSA), pre-start documentation and checks, associated pre-requisite procedures when completing site activities	6-monthly	L Cross	Effective

S/No	Overall Control Effectiveness	Current Consequence	Current Likelihood	Current Risk Rating	Risk Assessment Frequency	Risk Treatment Option	Acceptance Comment	Target Consequence	Target Likelihood	Target Risk Rating
1	Effective	Major	Possible	High	6-monthly	Treat		Major	Rare	Moderate

S/No	Action Plan	Action Owner	Due Date	Status
1	Project to replace the affected 66kV pin and cap insulators, transformer bushings and switchgear (66kV and 22kV)	M Chng	31/12/29	On Track

Risk Register	North Heidelberg (NH) Redevelopment		
Participants:	Alan Shu, Jignasa Sharma, Kopeeswaran Vaikundan, David Craven, Jon Bernardo	Workshop Date: 6/9/2024	MS Teams

S/No	Business Unit	Business Objective Category	Risk type	Risk Title	Risk Description	Root Causes Category	Root Causes - Description (Contributing Factors)	Risk Consequence Category	Risk Consequence - Description	Risk Owner	Untreated Consequence	Untreated Likelihood	Untreated Risk Rating	Current Controls	Control Assessment Frequency	Control Owner	Control Effectiveness	Overall Control Effectiveness	Current Consequence	Current Likelihood	Current Risk Rating	Risk Assessment Frequency	Risk Treatment Option	Acceptance Comment	Action Plan	Action Owner	Due Date	Status	Target Consequence	Target Likelihood	Target Risk Rating
2	Jemena Networks - Electricity	Sustainability	O-Business Continuity	Circuit Breaker Failure	Failure of the circuit breaker to operate as intended.	Resources – Assets, Cash, Equipment, Property	**Resources** - Circuit breaker due to condition and age (end of life)	Operational	- Unable to operate the breaker as intended - Autoreclose and manual close control of the breaker are compromised. - Loss of supply to a high profile HV customer and residential customers. - Fault current through the 66kV lines will be higher with the 66kV loop open (lines are not in parallel) which may result in CT saturation, causing protection maloperation with possibility of a station black. - Negative reputational impact - Regulatory investigations	M Ciavarella	Severe	Likely	High	Primary Asset Class Strategy	6-monthly	M Chng	Effective	Effective	Severe	Likely	High	6-monthly	Treat		Project to replace the affected circuit breakers	M Chng	31/12/29	On Track	Severe	Rare	Moderate
														VESI Switchgear Manual	6-monthly	M Gardiner	Effective														
														The VESI Green Book	6-monthly	M Gardiner	Effective														
														Emergency management plan	6-monthly	F Dunk	Effective														
														Stakeholder/Customer engagement plan and procedures	6-monthly	J Ng	Effective														
														Job Safety Assessments (JSA), pre-start documentation and checks, associated pre-requisite procedures when completing site activities	6-monthly	L Cross	Effective														

Risk Register	North Heidelberg (NH) Redevelopment		
Participants:	Alan Shu, Jignasa Sharma, Kopeeswaran Vaikundan, David Craven, Jon Bernardo	Workshop Date: 6/9/2024	MS Teams

S/No	Business Unit	Business Objective Category	Risk type	Risk Title	Risk Description	Root Causes Category	Root Causes - Description (Contributing Factors)	Risk Consequence Category	Risk Consequence - Description	Risk Owner	Untreated Consequence	Untreated Likelihood	Untreated Risk Rating
3	Jemena Networks - Electricity	Sustainability	O-Business Continuity	Transformer bushing failure	Failure of the transformer to operate as intended.	Resources – Assets, Cash, Equipment, Property	**Resources** - Defective Transformer due to condition	Operational	- Unable to operate the transformers intended - Loss of supply to a high profile HV customer and residential customers. - Fault current through the 66kV lines will be higher with the 66kV loop open (lines are not in parallel) which may result in CT saturation, causing protection maloperation with possibility of a station black. - Negative reputational impact - STIPIS financial penalties - Regulatory investigations	M Ciavarella	Severe	Likely	High

S/No	Current Controls	Control Assessment Frequency	Control Owner	Control Effectiveness	Action Plan	Action Owner	Due Date	Status
3	Primary Asset Class Strategy	6-monthly	M Chng	Effective	Project to replace the affected transformer bushings	M Chng	31/12/29	On Track
	VESI Switchgear Manual	6-monthly	M Gardiner	Effective				
	The VESI Green Book	6-monthly	M Gardiner	Effective				
	Emergency management plan	6-monthly	F Dunk	Effective				
	Stakeholder/Customer engagement plan and procedures	6-monthly	J Ng	Effective				
	Job Safety Assessments (JSA), pre-start documentation and checks, associated pre-requisite procedures when completing site activities	6-monthly	L Cross	Effective				

S/No	Overall Control Effectiveness	Current Consequence	Current Likelihood	Current Risk Rating	Risk Assessment Frequency	Risk Treatment Option	Acceptance Comment	Target Consequence	Target Likelihood	Target Risk Rating
3	Effective	Severe	Possible	Significant	6-monthly	Treat		Severe	Rare	Moderate

Risk Register	North Heidelberg (NH) Redevelopment		
Participants:	Alan Shu, Jignasa Sharma, Kopeeswaran Vaikundan, David Craven, Jon Bernardo	Workshop Date: 6/9/2024	MS Teams

S/No	Business Unit	Business Objective Category	Risk type	Risk Title	Risk Description	Root Causes Category	Root Causes - Description (Contributing Factors)	Risk Consequence Category	Risk Consequence - Description	Risk Owner	Untreated Consequence	Untreated Likelihood	Untreated Risk Rating	Current Controls	Control Assessment Frequency	Control Owner	Control Effectiveness	Overall Control Effectiveness	Current Consequence	Current Likelihood	Current Risk Rating	Risk Assessment Frequency	Risk Treatment Option	Acceptance Comment	Action Plan	Action Owner	Due Date	Status	Target Consequence	Target Likelihood	Target Risk Rating
4	Jemena Networks - Electricity	Sustainability	O-Business Continuity	Secondary Systems failure	Failure of legacy Secondary Systems	Resources – Assets, Cash, Equipment, Property	**Resources** - Defective Protection, Control, DC systems, SCADA and Communications equipment due to legacy design, condition and age (end of life)	Operational	- Unable to operate the Secondary Systems intended - Loss of supply to a high profile HV customer and residential customers. - Negative reputational impact - STIPIS financial penalties - Regulatory investigations	M Ciavarella	Severe	Likely	High	Secondary Asset Class Strategy	6-monthly	D Bonavia	Effective	Effective	Severe	Possible	Significant	6-monthly	Treat		Project to replace the affected Secondary Systems	D Bonavia	31/12/29	On Track	Severe	Rare	Moderate
														VESI Switchgear Manual	6-monthly	M Gardiner	Effective														
														The VESI Green Book	6-monthly	M Gardiner	Effective														
														Emergency management plan	6-monthly	F Dunk	Effective														
														Stakeholder/Customer engagement plan and procedures	6-monthly	J Ng	Effective														
														Job Safety Assessments (JSA), pre-start documentation and checks, associated pre-requisite procedures when completing site activities	6-monthly	L Cross	Effective														

Appendix C
Preliminary Options Assessment

C1. Option 5 - Non-network solution

This option involves non-network or standalone power systems (SAPS) that typically address existing or emerging network capacity limitations in our network. Should network capacity limitations be caused by the condition or serviceability of one or more zone substation asset, a non-network solution can be considered as an alternative to mitigate the consequential risks associated with the affected asset.

Non-network and SAPS solutions could be delivered through embedded generation, storage, or demand-side management programs (or combination thereof), to defer or reduce in scope, traditional network augmentation solutions or asset replacement. Such solutions need to have a sufficient number of proponents participating, to provide the aggregate level of dispatchable capacity needed. This could then mitigate the consequential risks of continuing to operate at risk assets.

The aim when defining potential credible non-network and SAPS options, is to test whether non-network or SAPS solutions (or combination of) is a viable way to avoid or reduce the scale of a network investment, in a way that efficiently addresses the identified need. The criteria we use to assess the potential credibility of non-network or SAPS solutions includes:

- **Addressing the identified need**: being able to reduce or eliminate the supply reliability risk (EUE) associated with the identified need.
- **Technically feasible**: there being no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or potentially better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

Notwithstanding our approach to seeking efficient solutions to project augmentation, we have undertaken a high-level assessment of non-network options by considering the benefits of deferring expenditure by one year against a plausible alternative of procuring capacity from the market based on recent RIT-D responses. Applying this methodology to distributed storage solutions, we determined that the installed costs[19] of $37.7M is greater than the $35.8M installed costs of the preferred option. Therefore, a non-network option is not the preferred approach based on program-wide network benefits alone.

[19] Installed cost of $500/kWh x $67.9M present value reliability benefit ÷ $45.006/kWh VCR ÷ 20 years analysis period = $37.7M

Appendix D
Cost Breakdown

D1. Cost Breakdown

Cost Summary

NH ZSS Redevelopment Cost Breakdown

Item	Total Budget	
Direct Labour, Subcontract, Preliminaries, Materials and Plant		
Line Works	3,409,359	includes HV UG cable and general works
Primary Works	12,249,306	includes sub-t bays, HV indoor bays, transformers, REFCL, primary connections
Secondary Works	2,269,908	inlcudes HV, Sub-T protection and control, SCADA works, Metering, Instrumentation
Civil Infrastructure	882,803	includes cable trenches/conduits
AC & DC Power Supplies	700,001	
Civil Contractor Preliminaries	193,091	
General Estimate	4,650,565	Includes Site Preliminaries, Design Contract, design, planning, project and construction management, labour)
Jemena Indirect Costs	2,123,485	
Outages	136,100	
Total Direct Labour, Subcontract, Preliminaries, Materials and Plant	**26,614,618**	*74.4% of Total Costs*
Risk Allocation		
Total Risk Allocation	**3,076,421**	*8.6% of Total Costs*
Overheads		
Total Overheads	**6,081,297**	*17.0% of Total Costs*
Total Costs	**35,772,335**	