Jemena Electricity Networks (Vic) Ltd

Footscray West Zone Substation (FW)
Transfomer, Switchgear and Relay Condition Risk

RIT-D Stage 3: Final Project Assessment Report

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Footscray West Zone Substation (FW) Transfomer, Switchgear and Relay Condition Risk

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Executive summary

Jemena Electricity Networks (Vic) Ltd (**JEN**) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The network service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

Our customers expect us to deliver a reliable electricity supply at the lowest possible cost. To do this, we must choose the most efficient solution to address emerging network issues. This means choosing the solution that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**).

This Final Project Assessment Report (**FPAR**) prepared under clause 5.17.4(o) of the National Electricity Rules (**NER**) forms Stage 3 of the Regulatory Investment Test for Distribution (**RIT-D**) consultation process. It sets out the matters detailed in the Draft Project Assessment Report (**DPAR**) published on 26 October 2022, and summarises the submissions received on that report. The DPAR quantified the reliability of supply and safety risks associated with the deteriorating condition of network assets within the Footscray West zone substation (**FW**) supply area. It analysed a range of credible options for economically mitigating those risks, including identifying the preferred option.

Identified need

FW is a 66/22kV zone substation owned and operated by Jemena, providing power to approximately 14,385 customers in the suburbs of Yarraville, Kingsville and West Footscray, in Melbourne's inner west.

The condition of the 66/22kV transformers, 22kV switchgear, protection relays and other equipment within FW is deteriorating. Jemena has assessed there is now an unacceptable risk of asset failure, with significant consequences for staff safety, and the reliability of electricity supply to Jemena's customers within the supply area. While there is a need to remove these assets from service, there also remains a need to continue to supply electricity to customers within the area supplied by these assets.

The most urgent concern for Jemena is the evidence of escalating partial discharges (**PD**) from the switchgear at FW, and the threat this poses to staff safety and customer supply reliability. Removing the aged switchgear from service is a priority task given the risk will increase further over time. A further concern is that two of the three existing power transformers are more than 56 years old and are showing signs of accelerating deterioration in their condition as they approach end-of-life. The third power transformer contains toxic, carcinogenic Polychlorinated Biphenyl (**PCB**) oil. The protection systems around these assets are also deteriorating and no longer considered fit for purpose.

Jemena has confirmed FW as a priority for investment based on two key needs:

- Firstly, the need to protect power sector workers and members of the public from harm caused by unplanned equipment failure (Safety); and,
- Secondly, the need to maintain a reliable power supply to the residences and businesses that are dependent on the power supply from this zone substation (Reliability).

RIT-D process

Distribution network service providers (**DNSPs**) are required to undertake the RIT-D process to identify the investment option that best addresses an identified need on the network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM (the preferred option).

The RIT-D applies in circumstances where a network problem (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $6 million.

Options considered

Jemena considered the credibility of potential non-network or stand-alone power system (**SAPS**) options as alternatives or supplements for the preferred network option.

A *RIT-D Stage 1: Non-Network Options Screening Report Notice of determination*, published on Jemena's website on 11 October 2022, was prepared to establish whether the currently proposed network solution to address the need, could be changed in scope or otherwise altered in response to a non-network or SAPS solution.

Jemena also developed a range of network options to remediate the assets that are in poor condition and to continue to meet the electricity demand requirements of customers in the area. These options are listed below, and compared to the base case "Do Nothing" Option 1:

- Option 1 – Base case "Do Nothing", i.e., run assets to failure;
- Option 2 – Replace one switchboard, one transformer and their relays at FW;
- Option 3 – Replace two switchboards, two transformers and their relays at FW; and
- Option 4 – Replace all three switchboards, three transformers and their relays at FW.

Each network option has two variants:

- Option 'a' – In-situ: replace poor condition assets; new assets in the same switchyard location; and
- Option 'b' – Rebuild: retire poor condition assets; new assets established in a vacant area of the switchyard.

A *RIT-D Stage 2: Draft Project Assessment Report*, published on Jemena's website on 26 October 2022, was prepared to present the economic evaluation of the credible options and to identify the proposed Preferred Option.

There were no submissions received on either stage of the RIT-D consultation.

Preferred option

The options analysis and economic evaluation undertaken and documented in this FPAR reiterates the conclusions made in the DPAR in that:

- Option 4b is the preferred network option; and,
- There were no credible non-network or SAPS options, or combinations of non-network options with network options that could defer the need for the preferred network option.

Option 4b (the Preferred Option) was tested under a range of sensitivities and scenarios including variations in costs and value of customer reliability (for example). In each case, Option 4b was confirmed to provide positive economic benefits and is the highest-ranked option.

Option 4b satisfies the requirements of the RIT-D.

Table 1–1 below summarises the cost-benefit analysis, based on a scenario weighting for the preferred option.

Table 1–1: Summary of Cost Benefit Analysis for Preferred Option ($M, 2022)

Present Value of Costs	'Do Nothing' Option 1	'Preferred' Option 4b
Network capital investment	-	(40.6)
Additional opex investment (O&M)	-	(3.2)
Expected unserved energy (EUE)	(684.7)	(0)
Safety risk	(97.4)	(0)
Net Present Value of Benefits	**-**	**738.3**

Jemena intends to proceed with the preferred network option as soon as possible to address the increasing safety and reliability of supply risks at FW associated with the deteriorating condition of its network assets.

Next steps

This FPAR concludes the RIT-D consultation process for the Footscray West Zone Substation (FW) Transformer, Switchgear and Relay Condition Risk.

In accordance with clause 5.17.5 of the NER, within 30 days of the date of publication of this FPAR, any party disputing the conclusion made in this FPAR should give notice of the dispute in writing, setting out the grounds for the dispute (the dispute notice) to the AER.

Jemena will proceed to implement the preferred option if there are no dispute notices within 30 days of the FPAR publication date.

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Glossary

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Contingency (or 'N-1' condition)	An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Energy-at-risk	The energy at risk of not being supplied if a contingency occurs.
Expected unserved energy (EUE)	Refers to an estimate of the long-term, probability-weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Limitation	Refers to a constraint on a network asset's ability to transfer power.
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs.
Jemena Electricity Networks (Vic) Ltd	One of five licensed electricity distribution networks in Victoria, Jemena Electricity Networks (Vic) Ltd is 100% owned by Jemena and services over 366,000 customers covering north-west greater Melbourne.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt Ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.
Probability of Exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Distribution (RIT-D)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a prescribed limit, in the National Electricity Market (NEM).
System Normal (or 'N' condition)	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices
Value of Customer Reliability (VCR)	Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
Zone Substation	Refers to the location of transformers, ancillary equipment and other supporting infrastructure that facilitates the electrical supply to a particular zone in Jemena's electricity network.

10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by Jemena, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC derived by NIEIR and adopted by Jemena, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE condition (winter)	50% POE and 10% POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

Abbreviations

ACS	Asset Class Strategy
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CB	Circuit Breaker
CBRM	Condition-Based Risk Management
DM	Demand Management
DPAR	Draft Project Assessment Report
EG	Embedded Generation
EUE	Expected Unserved Energy
FPAR	Final Project Assessment Report
FW	Footscray West Zone Substation
HV	High Voltage
IR	Insulation Resistance
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo-Volts
LV	Low Voltage
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere
MW	Mega Watt
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
O&M	Operations and Maintenance
PCB	Polychlorinated Biphenyl
PD	Partial Discharge
POE	Probability of Exceedance
PV	Photovoltaic
RFI	Radio Frequency Interference
RIT-D	Regulatory Investment Test for Distribution
SAPS	Stand-alone Power System
VCR	Value of Customer Reliability

1. Introduction

This chapter outlines the purpose of the Regulatory Investment Test for Distribution (**RIT-D**) regarding the Footscray West Zone Substation (**FW**) supply area, and the structure of this Final Project Assessment Report (**FPAR**).

1.1 RIT-D purpose and process

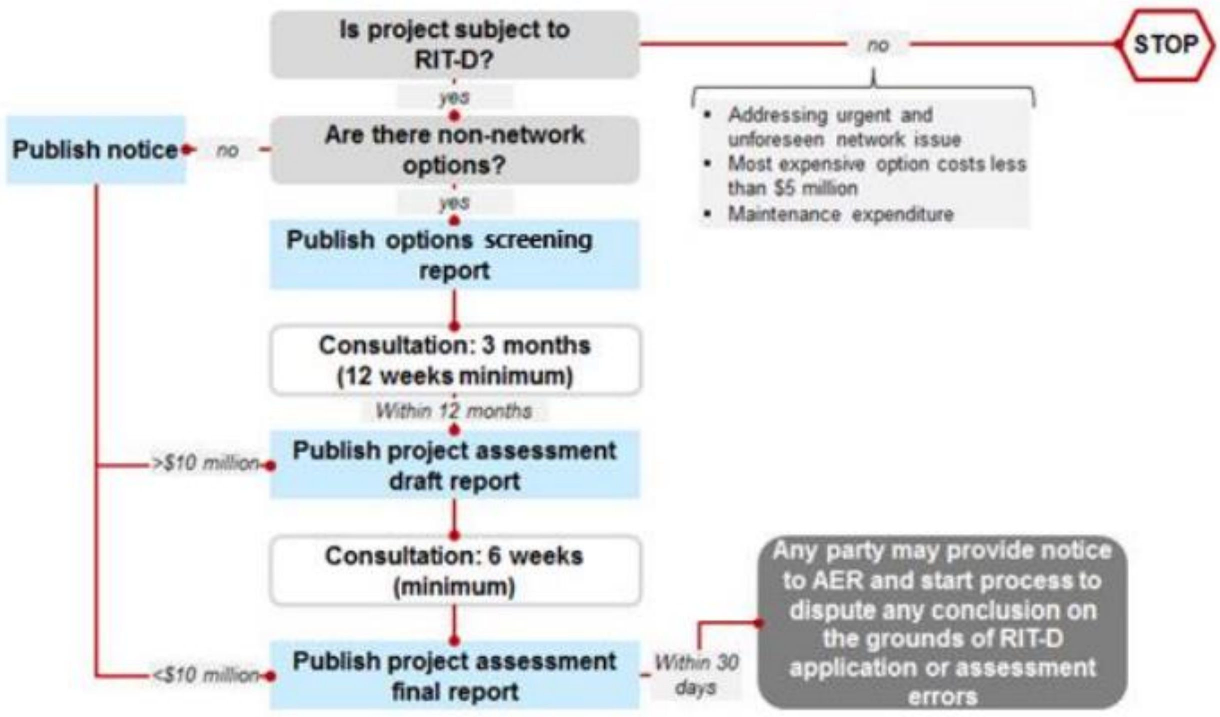
Jemena is required to undertake the RIT-D process to identify the investment option that best addresses an identified need on its electricity network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**) (the preferred option).

The RIT-D applies in circumstances where a network limitation (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $6 million. The identified need at FW is driven by the increasing safety and reliability of supply risks associated with the deteriorating condition of its transformer, switchgear and protection relay assets. The capital cost of the most expensive potential credible option to address this need at FW has triggered the requirement for a RIT-D.

Jemena must also consider non-network and stand-alone power system (**SAPS**) options when assessing credible options to address the identified need. As part of the RIT-D process, a non-network options report must be prepared where a non-network or SAPS solution may be potentially viable to address the identified need. As such, Jemena has considered the credibility of potential non-network and SAPS options, as alternatives or supplements to credible network options, where they could be changed in scope or otherwise altered in response to a credible non-network or SAPS solution.

The RIT-D process is summarised in Figure 1-1

Figure 1–1: The RIT-D Process[1]



[1] Source: [AER Application Guidelines RIT-D](#) (August 2022).

For the identified need at FW, a viable non-network or SAPS option would involve implementing measures capable of meeting FW's maximum forecast demand and energy requirements of its connected customers with a maintained level of service. The total requirement at FW from all power sources is 64 MW, which is the 10% probability of exceedance (**PoE**) maximum forecast demand at FW in 2026. A non-network option supplying 64 MW would allow all of the assets in poor condition at FW to be retired. However, a non-network solution supplying 31 MW may be possible, if some of the network assets are replaced along with the non-network solution. Smaller non-network solutions would not provide sufficient capacity to be viable options to address the identified need.

On 11 October 2022, Jemena published a *Non-Network Options Screening Report Notice of determination* on its website, prepared under clause 5.17.4(d) of the National Electricity Rules (**NER**), forming Stage 1 of the RIT-D consultation process. This analysed the credibility of non-network and SAPS options to address the identified need at FW based on the above requirements. The analysis concluded that (in this instance) a non-network or SAPS solution could not (either on its own or in combination with a network solution) provide a credible alternative to the preferred network option.

Jemena also developed a range of network options to remediate the assets that are in poor condition, and that are able to continue to meet the electricity demand requirements of customers in the FW supply area, to address the identified need.

On 26 October 2022, Jemena published a Draft Project Assessment Report (DPAR), prepared under clause 5.17.4(i) of the NER, forming Stage 2 of the RIT-D consultation process. The DPAR presented the economic evaluation of the credible options, and identified the proposed Preferred Option. The consultation on the DPAR has now closed.

This FPAR, prepared and published under clause 5.17.4(o) of the NER, forms Stage 3 of the RIT-D consultation process. It sets out the matters detailed in the DPAR, and summarises the submissions received on that report.

1.2 Structure of this report

The objective of this FPAR is to present the results of an economic evaluation that assesses the credible options for addressing the identified need at FW, and to confirm the preferred option.

The contents of this FPAR are set out as follows:

- Section 2 details the FW supply area;
- Section 3 articulates the identified need regarding the FW supply area;
- Section 4 sets out the key assumptions relating to the identified need;
- Section 5 sets out the credible non-network and/or SAPS options assessed to address the identified need;
- Section 6 sets out the credible network options assessed to address the identified need;
- Section 7 summarises the submissions received on the DPAR;
- Section 8 summarises the method used to quantify market benefits;
- Section 9 presents the net present value assessment results for the credible options assessed; and
- Section 10 details the technical characteristics of the proposed preferred credible option, and the next steps.

2. Background

This section provides an overview of the Footscray West supply area, describes the general arrangement of Footscray West Zone Substation (**FW**), and gives an overview of the network capability.

2.1 Network supply arrangements

Jemena Electricity Networks (Vic) Ltd (**Jemena**) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The Jemena service area covers 950 square kilometres of northwest greater Melbourne and includes some major transport routes and the Melbourne International Airport, which is located at the approximate physical centre of the network. The network comprises over 6,900 kilometres of electricity distribution lines and cables, delivering approximately 4,400 GWh of energy to around 366,000 homes and businesses for several energy retailers. The network service area spans from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

FW consists of three 66kV/22kV power transformers rated at 30MVA each, two 66kV bus-tie circuit breakers and eight 22kV distribution feeders that supply approximately 14,385 Jemena customers (including several major customers), from an indoor 22kV switchboard comprising three buses.

The ratings of the key assets are:

- Three transformers each rated at 30MVA continuous, each with a cyclic rating of 35MVA;
- Three 22kV buses each rated at 1,200 Amps (45.7MVA) with space for 4 circuit breakers on each switchboard, of which:
  - 8 are currently used for feeder circuit breakers to supply customers in the FW supply area; and
  - 2 are used for capacitor banks that provide 9.14MVAr and 14.6MVAr for power factor correction.

The total nameplate rating of the zone substation is 90MVA. The N-1 rating is based on the transformer cyclic rating of 35MVA. With two of the three transformers in service, the N-1 rating is 70MVA.

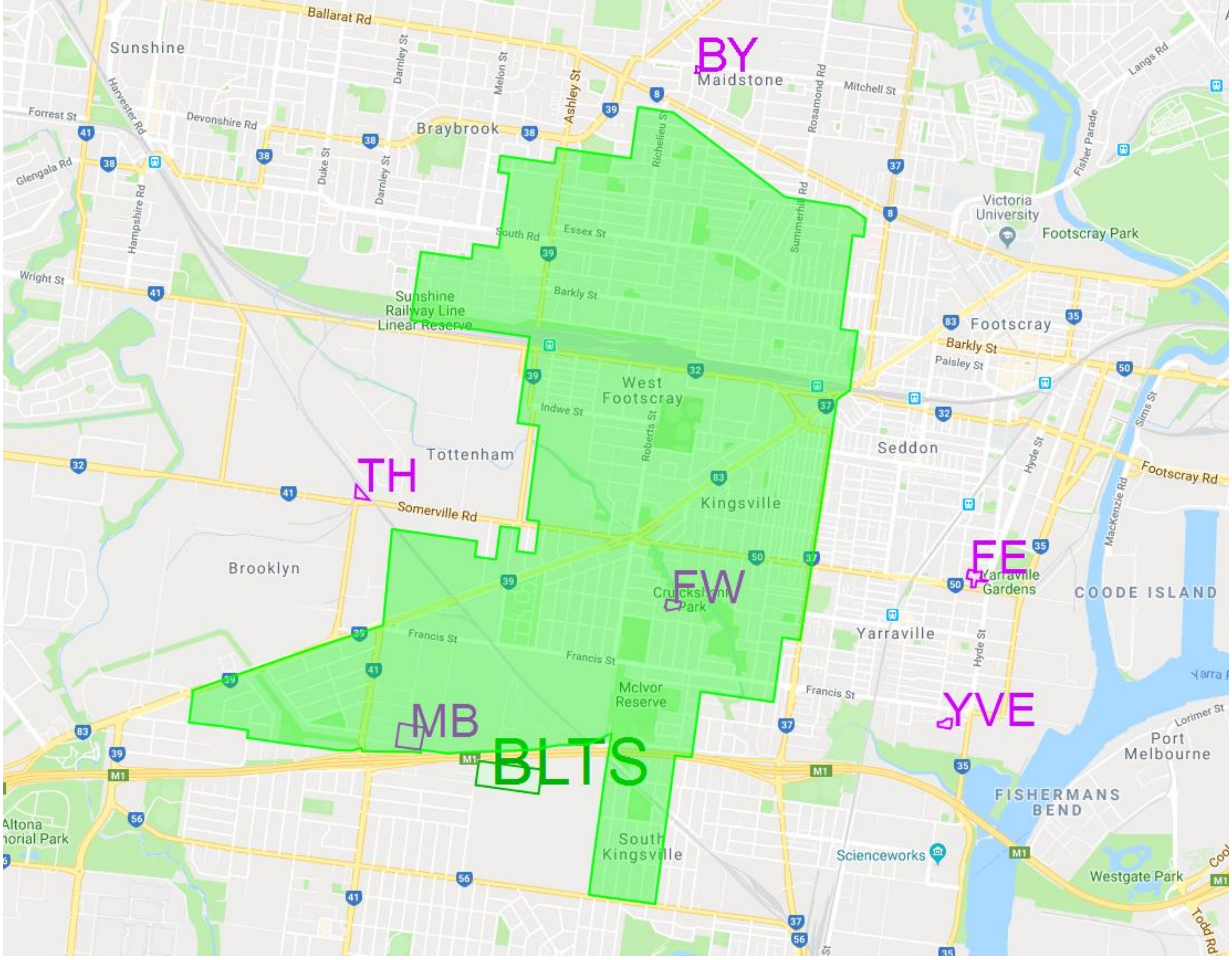
Based on Jemena's 2022 maximum demand forecasts, FW's maximum demand is expected to increase rapidly over the next few years as a result of some large customer connections occurring in the FW supply area, on a backdrop of marginally declining underlying maximum demand. The FW maximum demand is forecast to be 44.4MVA for the summer of 2023 under 10% PoE. By 2032 it is forecast that maximum demand will be approximately 59.4MVA. The highest maximum demand over the 10-year planning horizon is forecast to be 64.3MVA for summer 2026.

2.2 General arrangement

Figure 2–1 shows the FW Supply Area as it currently stands, including the adjacent areas supplied by Braybrook (**BY**), Footscray East (**FE**), Yarraville (**YVE**) and Tottenham (**TH**) zone substations.

The supply area comprises Melbourne's inner-west suburbs of West Footscray, Kingsville and Yarraville.

Figure 2–1: Footscray West Supply Area



3. Identified need

Jemena has identified the FW supply area as a priority for investment based on two key identified needs:

- Firstly, the need to protect power sector workers and members of the public from harm caused by equipment failure (Safety); and,
- Secondly, the need to maintain a reliable power supply to the residences and businesses within the supply area that are dependent on the power supply from this part of the distribution network (Reliability).

3.1 First identified need – safety

The primary need in this case relates to maintaining the safety of Jemena employees, and the general public. The ability to maintain a safe network at FW is increasingly difficult due to the poor and deteriorating condition of major assets at FW, which are at risk of failure.

Jemena's approach to safety risk is to categorise the risk into three categories - intolerable, As Far As Practicable (**AFAP**) and tolerable. The AFAP principle recommends risk reduction measures be implemented unless the cost, time or form of the risk reduction measure is grossly disproportionate to the benefit gained from the reduced risk.

Consistent with the AFAP principle, Jemena has undertaken a risk management programme to minimise risks relating to the condition deterioration of aging assets within FW. In the short term, Jemena is assessing whether any cost-effective risk mitigation controls can be considered to reduce and minimise the risks of a safety incident until the identified need is addressed. For example, inhibiting the feeder circuit breaker (**CB**) auto-reclose functions to reduce potential electrical stresses, similar to the risk mitigation measures implemented at the Preston zone substation before it was retired. Based on the experience of the risk mitigation controls applied at the Preston zone substation, the costs associated with these actions will be small compared with the cost of an associated unplanned failure of the assets of concern.

The safety risk to Jemena employees and the general public, arising from potential major failures of network assets is quantified by safety risk costs based on asset condition. At FW, the safety risk cost is considered to be significant. The safety risks must be addressed according to the AFAP principle. A "Do Nothing" (or run to failure) approach would result in the aging assets remaining in service, deteriorating further, and completely failing to address safety concerns. An investment to address the deteriorating condition of assets at FW is needed.

The need is driven in particular by the deteriorating condition of the power transformers, switchboards, circuit breakers and protection relays at FW, which are at risk of failure and pose a serious safety risk.

The major issue is the presence of partial discharge (**PD**) within the switchboards, its potential impact on personnel safety, and the lack of spares to recover from a catastrophic failure. Insulation levels within the equipment will continue to degrade over time due to the presence of PD. PD levels will consequently rise and failure will ultimately occur.

The switchboard has been subjected to condition monitoring tests in 2012 and 2018. The test results from the 2018 condition monitoring demonstrated further insulation degradation since 2012 in all of the tests conducted (i.e., Partial Discharge, Dielectric Dissipation Factor & Capacitance and Insulation Resistance). Catastrophic insulation failure could be triggered by lightning and other line surges at any time, while insulation degradation at normal service voltage can be cyclical due to temperature variations and will increase over time, ultimately resulting in failure.

There have been 45 recorded defects associated with the FW 22kV switchgear. In addition, 21 defects have occurred on the same model switchgear at an adjacent zone substation (which has now been rebuilt).

It is expected that one 22kV indoor bus could fail beyond repair due to poor condition in the next five years. The probability of the 22kV bus failing in any given year is taken to be 1/5 = 20%. This failure rate is likely to increase with age as the equipment condition deteriorates further.

The presence of PD means that the switchboards and associated switchgear need to be replaced as an urgent priority to mitigate significant safety risks to Jemena staff. The indoor 22kV metal-clad switchboard and its associated circuit breakers manufactured by Metropolitan Vickers are estimated to be 85 years old, and their condition has degraded to a point where employee safety, reliability and security of customer supply will be affected. No other Australian electricity business has this switchgear installed (meaning that there is very limited availability of spare parts and staff with expertise in maintenance). The switchgear is operating beyond its engineering life.

A further concern is that two of the three existing power transformers are more than 56 years old and are showing signs of accelerating deterioration in their condition as they approach end-of-life, with the third power transformer containing toxic, carcinogenic Polychlorinated Biphenyl (**PCB**) oil. The transformer is at risk of oil leakages as it continues to age.

In addition, the protection and control relays at this zone substation have deteriorated and are no longer regarded as being fit for purpose. The majority of the protection relays are legacy electromechanical relays without real-time health monitoring features. These relays are used to protect major primary assets including the power transformers and the 66kV and 22kV buses. These relays were commissioned in the late 1960s, with a life expectancy of around 40 years, and as such have limited spares. Failure of these relays will remain undetected, exposing the network to reliability and safety risks, with a significant risk that faults are not detected and safely isolated. The protection and control relays are operating beyond their engineering life.

The potential safety risks of an asset failure are listed below:

- Severe injury or death to Jemena's operating personnel and the general public in the vicinity of the substation;
- Step and touch potentials causing electrocution; and
- An extended period of power supply interruption for customers, impacting community health and safety.

The replacement or retirement of the transformers, switchgear and associated relays is recommended and consistent with regulatory requirements in clause 6.5.7 of the National Electricity Rules (**NER**), and section 19.2 of the Electricity Distribution Code of Practice (**EDCoP**). Credible network, non-network or SAPS solutions would be required to allow the assets of concern at FW to be retired, to ensure the ongoing maintained safety of staff and the general public.

3.2 Second identified need – reliability of supply

With the first identified need requiring poor-condition assets to be removed from service to maintain safety, there is a risk of deteriorating supply reliability, because of reduced capacity. Furthermore, failure to remove such assets from service will result in power supply interruptions if there is a major unplanned asset failure. Either avenue would be observed by customers as more frequent and longer power supply outages over time.

Jemena's reliability of supply planning standard for the capacity of its assets is based on a probabilistic planning approach which:

- Directly measures customer (economic) outcomes associated with current and future network limitations;
- Provides a thorough cost-benefit analysis evaluation of network or non-network options; and;
- Estimates Expected Unserved Energy (**EUE**) which is defined in terms of megawatt hours (MWh) per annum, and expresses this economically by multiplying it with a Value of Customer Reliability (**VCR**) ($/MWh).

Jemena uses this approach to identify, quantify and prioritise investment in the distribution network. Typically, the EUE is calculated by understanding the load-at-risk for each zone substation. This is normally calculated through modelling load-at-risk under system normal, and if any single item of equipment was out of service (called a normal minus one or N-1 scenario), taking into account the probability of an asset failure.

Credible network, non-network or SAPS solutions should seek to maintain levels of supply reliability that are at threat from deteriorating asset condition. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply the load under N and N-1 network conditions, such that the cost of EUE and safety risk exceeds the annualised cost of the investment.

To maintain reliability of supply levels, credible solutions would be required to address a deteriorating reliability need. This could be achieved through a range of solutions, including:

- Meeting the identified need in its entirety through a non-network or SAPS option allows all of the poor-condition assets at FW to be retired.
- Replacing one switchboard, one transformer and the associated protection and control relays at FW providing 30MVA of capacity, with the residual need addressed through a non-network option to allow those assets to be retired.
- Replacing two switchboards, two transformers and the associated protection and control relays at FW providing 60MVA of capacity, with the residual need addressed through a non-network option to allow those assets to be retired.
- Replacing all three switchboards, three transformers and the associated protection and control relays at FW providing 90MVA of capacity, with no non-network options, allowing all of the poor condition assets at FW to be replaced.

Credible network, non-network or SAPS solutions would be required to replenish the capacity that is withdrawn by the assets that are retired (subject to the forecast maximum demand at FW), to ensure the ongoing reliability of supply is maintained for customers. Any other option would likely only partially address the identified need.

4. Assumptions relating to the identified need

In line with the purpose of the RIT-D, as outlined in Clause 5.17.1 (b) of the NER, an investment to address the identified need relating to the safety and reliability of supply risks at FW could increase the sum of customer and producer surplus in the NEM; that is an increase in the net economic benefit to all those who produce, consume and transport electricity in the NEM. This net economic benefits increase is driven by avoiding EUE (reduced involuntary load shedding) and safety risk costs associated with the deteriorating, poor condition of network assets at FW. This benefit is balanced against each credible option's cost and used to identify the preferred option and its timing.

To achieve this outcome, Jemena applies a probabilistic planning method that considers the likelihood and severity of critical network conditions and outages, based on the forecast demand and associated capacity ratings, asset condition and the associated asset failure rates. The method compares the forecast cost to consumers of energy supply interruptions (e.g., when demand exceeds available capacity) and safety incidents (e.g., when an unplanned asset failure occurs) against the proposed investment cost to mitigate the EUE and safety risk. The annual cost to consumers is calculated by multiplying the EUE (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the VCR. This, combined with the safety risk cost, is then compared with the annualised investment cost, to identify optimal timing.

To ensure the net economic benefit is maximised, an investment will only be undertaken if the benefits outweigh the cost of the proposed investment to reduce the unserved energy, and to meet AFAP for safety. Investments are not always economically feasible and this planning method therefore carries an inherent risk of not being able to fully supply demand under some possible (but rare) events, such as a network outage coinciding with peak demand periods. The probabilistic planning method that we apply is further detailed in our Distribution Annual Planning Report (**DAPR**).

The key assumptions that have been applied in quantifying the FW supply area limitations for this FPAR are outlined in this section and include maximum demand forecasts, asset condition and capacity ratings, and the associated asset failure rates and consequences.

4.1 Asset condition

The assets at FW that are at risk of failure due to their condition include the:

- three 66kV/22kV power transformers;
- three 22kV switchboards including their associated switchgear;
- other primary assets such as outdoor buses and feeder exit cables; and
- associated protection and control relays and other secondary assets that monitor, control and protect the above assets.

From Jemena's Asset Class Strategies (**ACS**) and with the application of Jemena's Condition Based Risk Management (**CBRM**) modelling using inputs from condition testing and monitoring, the above assets at FW are assessed to be at a 'high' risk of failure.

CBRM develops a Health Index for each asset on a scale from 0 to 10. Values of health index above 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 the end of life and probability of failure. The concept is illustrated schematically below in Figure 4–1.

Figure 4–1: CBRM Health index

Condition	Health Index	Remnant Life	Probability of Failure
Bad	10	At EOL (<5 years)	High
Poor		5 - 10 years	Medium
Fair		10 - 20 years	Low
Good	0	>20 years	Very low

Based on CBRM, the total expected safety risk cost of equipment failure at FW is currently $3.5 million per annum. This is explained by equipment type in the sub-sections below. Due to the age and condition of the assets mentioned below, the annual cost of risk will continue to increase until the deteriorated assets are removed from service.

4.1.1 22kV switchboards and switchgear

Condition monitoring tests conducted in 2012 and 2018 on the indoor 22kV buses indicate that PD is present above service voltage. This indicates that insulation degradation has occurred. The damage due to PD cannot be stopped or reversed and the behaviour cannot be predicted. Overvoltage 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. Comparing the results between 2012 and 2018 shows further degradation of the primary insulation.

The 22kV switchgear is subject to a condition-based monitoring regime that is detailed in Jemena's Primary Plant ACS. These switchboards and switchgear are currently 85 years old, at the end of their engineering life and no longer supported by the manufacturer. In addition, the CBs associated with the 22kV indoor buses have a history of issues. The extent of the defects relating to mechanical faults is progressively becoming more serious as the assets age well beyond their life. The associated CB mechanisms are worn and on occasion fail to remain closed (trip free).

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 PD at near service voltage. If the insulation fails, the resulting electrical arc and pressure wave will not be contained within the switchgear, and the risk to employee health and safety is consequently elevated.

Spare busbar bushings and spare circuit breaker components are limited and, in most cases, non-existent. Repairs have been performed by welding components to renew wearing surfaces. This is not a long-term solution. Circuit breaker contacts have been re-engineered and there are no detailed drawings available to restore the components to their original condition. The busbars have paper Bakelite bushings, and the limited spares may not be in a serviceable condition.

The switchgear has a history of oil leaks from the circuit breaker and internal isolator compartments. This is not an issue that is driving the replacement of the switchgear, but it does require elevated levels of operating expenditure to manage. The incidence of oil leaks appears to be becoming more frequent. To date, the repairs have involved tightening bolts, but gaskets have now been compressed to the limit and costly replacement will be incurred in the future.

An added complication is the unique insulating oil used within the isolator compartments. The oil (Penetrol) has a very high viscosity. In the case of an oil leak, this can cause a flashover inside the switchgear and damage the equipment. Due to its properties and the low flash point of the oil, the fault may result in a fire that will affect adjacent equipment and buildings. The oil leaks also present a slip hazard and, in some cases, may be contaminated with PCBs which represent an environmental and safety hazard.

As FW is the only zone substation where this type of switchgear is used, maintenance of the bus and circuit breakers requires special procedures to maintain the safety of the personnel working on them. Measuring switchgear insulation requires inserting special test probes into HV compartments and removing earthing links that may be hazardous if procedures are not followed. Although this is a non-standard design, this is not a critical issue and is currently managed with work procedures. However, it exposes field personnel to increased safety concerns.

The internal 22kV isolators and earthing switches are immersed in oil and maintenance has not been required to date. However, considering the age of the switchgear, their condition will need to be assessed in the future and this will be a costly maintenance activity. This work can be undertaken with a gasket replacement. As noted above, an added complication is the unique insulating oil used within the isolator compartments.

Jemena's CBRM modelling was introduced in 2014 for switchgear assets and is used to assist in the development of asset investment plans using existing asset data and other information.

The CBRM modelling indicates that the FW No.1, No.2 and No.3 22kV buses have a current Health Index result of 8.41 (out of 10). This indicates that all three buses have serious issues, including degradation and wear-out failures, and due to the lack of spares the probability of failure is high. These modelling results are consistent with the issues identified. Six years from now (2028), if the switchgear is not replaced, the Health Index result would increase to 9.64.

For the 22kV CBs, the CBRM modelling indicates that they have a current Health Index result above 8.06. This indicates that the CBs are in poor condition. This modelling result is also consistent with the issues identified. By year 6 (2028), the highest CB result becomes 9.28 if no action is taken.

In this condition, the probability of failure of the switchgear at FW is significantly raised and the rate of further degradation will be relatively rapid. This modelling result is consistent with the defects and issues identified at the FW zone substation in recent years which are further detailed below. The health index and consequent risk of failure of assets at the FW zone substation will continue to increase if no action is taken.

The probability of a 22kV switchgear failure can only be estimated from limited historical data, engineering experience and condition test reports. The thermal fault due to high resistance connections is not uncommon for oil-filled CBs. The CB thermal condition and a trip-free operation due to mechanical wear will not be readily identifiable before any such event. The incidence of oil leaks associated with the FW switchgear is increasing and will ultimately necessitate major maintenance work to replace the gaskets.

There were 22 of this type of CB installed at FW (and an adjacent zone substation) and 71 fault records in 10 years. The major issue is the presence of PD approaching 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. The PD levels will rise and failure will ultimately occur.

Catastrophic insulation failure can be triggered by lightning and other line surges at any time. Insulation degradation at normal service voltage can be cyclical due to temperature variations or linear increases over the same period, ultimately resulting in failure.

Based on CBRM it is expected that one 22kV indoor bus could fail beyond repair due to poor condition in the next 5 years, the probability of the FW 22kV bus failing in any year is taken to be 1/5 = 20%. This failure rate is likely to increase with age.

The consequence of a catastrophic failure of the 22kV switchgear at FW would likely be an interruption of supply to the entire station due to smoke and potential fire. The switchgear contains bulk oil volume for insulation and to interrupt current. The scenario considered is the loss of two 22kV buses due to a bus section failure within the bus tie CB.

The expected risk cost for a 22kV switchboard, switchgear and bus failure has been determined as currently $3.2 million per annum. Due to the age and condition of the assets mentioned above, the risk cost above will continue to increase until the assets are removed from service.

4.1.2 66kV/22kV power transformers

Two of the three existing 66kV/22kV power transformers are more than 56 years old and are showing signs of accelerating deterioration in their condition as they approach end-of-life. The third power transformer contains toxic, carcinogenic PCB oil. The protection systems around these assets are also deteriorating and no longer considered fit for purpose. In particular, current transformer cores are shared and do not provide the full standard duplicated and backup protection needs required to continue to operate these aging assets safely.

The likelihood of a major transformer failure is approximately 1%. Given the condition issues are not associated with the transformer bushings, but rather the transformers themselves, the consequences of a transformer failure are likely to be minimal.

The expected risk cost for a power transformer failure has been assumed as $10,000 per annum. Due to the age and condition of the assets mentioned above, the risk cost above will continue to increase until the assets are removed from service.

4.1.3 Other primary assets

Condition of the 66kV circuit breakers

The 66kV bus tie circuit breakers represent a family of breakers with a history of mechanical failure and catastrophic bushing failures. These CBs (type LG4C) are no longer supported by the manufacturer and spare components are no longer available.

A CB can fail due to thermal, electrical or mechanical factors. However, while a typical failure mode is difficult to determine, most failures involve a failure to operate. The probability of a 66kV CB failure at FW 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 1990s and early 2000s, with these failures relating to the 66kV bushings. These CBs are no longer supported by the manufacturer and spare components such as 66kV bushings, turbulators, solenoids and mechanism components are consequently no longer available. The known failure history of 66kV bushings is a risk to the safety of Jemena’s personnel.

An additional defect has been 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. This CB mechanism defect can prevent the CB from opening or closing. In this circumstance, if a sub-transmission line fault occurs, total loss of supply will be experienced at FW.

For the 66kV CBs, the CBRM modelling indicates that the 1-2 Bus Tie CB has a current Health Index result of 6.60 and the 2-3 Bus Tie CB has a current health index result of 6.60. This indicates that the CBs are in poor condition. This modelling result is also consistent with the issues identified. By year 6 (2028), the CB result becomes 8.15 (both CBs) if no action is taken.

The likelihood of a mechanical failure is low as these 66kV CBs are not called on to operate due to faults very often. Failures can be picked up during maintenance. Ten failure observations have occurred in the past thirty years giving a probability of failure of 1 in 3 years. Given that 16 of this type of CB are in service on Jemena’s network, the probability of the FW 66kV CB failing in any year is estimated to be 1/3/16 = 2%, but due to having two CBs at this station, the probability is 4%.

Considering a catastrophic bushing failure of 3 in 15 years and a population of 16 CBs, the probability of the FW 66kV CB failure scenario eventuating in any year is taken to be 1.25% (3/15/16), but for both CBs at the station, the probability is 2.5%.

The consequence of a catastrophic failure of the 66kV CBs at FW would likely be supply interruption to the entire station. The station could likely be off supply for up to 1 hour while the 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 expected risk cost for a 66kV CB failure has been determined as $15,000 per annum. Due to the age and condition of the assets mentioned above, the risk cost above will continue to increase until the assets are removed from service.

Condition of the outdoor 22kV transfer bus

The 22kV outdoor transfer buses are pin and cap 22kV insulators, a type with design deficiencies that can lead to in-service insulator failure, posing a safety risk to Jemena personnel. These insulators also consist of a galvanised steel pin cemented into the porcelain and over time as moisture corrodes the pin, the expansion of the rust causes the porcelain to crack and shear. Although various means are used to detect a possible failure such as visual inspection, maintenance and off-line PD detection, this defect may remain undetected until an isolator is operated, and the insulator shears off completely. A 22kV pin and cap insulator was found sheared off in an adjacent zone substation's capacitor bank which confirms that the insulators of this design are prone to failure.

There have been two recent incidents associated with the failure of 22kV pin and cap-type insulators on buses in Victoria. The first is an insulator sheared from the pin and resulting in the bus dropping to one metre above ground level - the bus remained alive and was discovered by an employee. The second occurred when an isolator was opened using an HV switch stick and the insulator sheared from the pin. The live conductor then fell onto an employee's shoulder.

A bus can fail due to thermal, electrical or mechanical factors. However, while a typical failure mode is difficult to determine, the likely failure would be due to insulator flashover or mechanical damage. The probability of an outdoor 22kV bus section at FW is low. For risk cost calculations, a 1% probability of failure in any particular year is used.

The consequence of a failure of an outdoor 22kV transfer bus section at FW would likely be supply interruption to one feeder and these customers would be off-supply until repairs were completed. However, the failure would have serious consequences if it occurred during switching operations and was the result of an operator opening or closing the 22kV underslung isolators on a feeder. Falling porcelain/equipment and/or contact with live 22kV conductors could cause permanent disability or even death to a staff member.

The expected risk cost for the 22kV transfer bus failure has been determined as $2,500 per annum. Due to the age and condition of the assets mentioned above, the risk cost above will continue to increase until the assets are removed from service.

Condition of the outdoor 66kV bus

The FW outdoor 66kV insulators were observed to have significant electrical discharge on most of the buses and disconnect switches. This issue causes Radio Frequency Interference (**RFI**) and ultimately may result in insulation failure. These insulators also consist of a galvanised steel pin cemented into the porcelain similar to the pin and cap 22kV insulators described above and may exhibit a similar failure mode in the future, which poses a serious safety risk to Jemena's personnel. Further to this, in 2020 during routine maintenance, the low insulation resistance (**IR**) of the No.1 66kV bus was measured.

For the 66kV insulators, the CBRM modelling indicates a current health index result of 7.96. This indicates that the insulators are in poor condition. This modelling result is also consistent with the issues identified. By year 6 (2028), the insulator result becomes 9.91 if no action is taken.

A bus can fail due to thermal, electrical or mechanical factors. However, while a typical failure mode is difficult to determine, the likely failure would be due to insulator flashover or mechanical damage. The probability of an outdoor 66kV bus section failure at FW is low. For risk/cost calculations, a 1% probability is used.

The consequence of a failure of an outdoor 66kV bus section at FW would likely be supply interruption to one transformer with no interruption to customer supply. Only a single event is considered. However, the failure would have serious consequences if it occurred during switching operations and was the result of an operator opening or closing the 66kV underslung isolators on a feeder. Falling porcelain/equipment and/or contact with live 66kV conductors could cause permanent disability or even death to a staff member.

The expected risk cost for a 66kV bus failure has been determined as $4,500 per annum. Due to the age and condition of the assets mentioned above, the risk cost above will continue to increase until the assets are removed from service.

Condition of the 22kV feeder exit cables

Analysis of the performance of HV paper lead cables has shown an increasing trend of failure in recent years. Jemena's investigation of the cables at FW has identified significant deterioration not only on the outer serving layer but on the lead sheath armour, which means the barriers from mechanical damage and moisture have been weakened, risking electrical failure. There have also been many incidents where faults have occurred at the old cable head at the feeder exit cable head pole due to electrical failure caused by moisture ingress and animal contact. There are no standard animal-proofing covers available for the old cable head construction and therefore animal strikes on the FW 22kV feeder exit cable head poles have occurred on average two to three times per year. There also have been many incidents of animal strikes on the feeder exit isolators, for which animal proofing is also not available, resulting in supply interruptions for customers.

High fault current flow will deteriorate all primary plant such as transformers and circuit breakers within FW, leading to increased maintenance requirements and diminishing asset life. Failure at the cable head also poses a safety risk to the public as shattered porcelain could cause death or serious injury to the public or cause damage to nearby third-party property.

Due to the poor condition of the feeder cables installed in 1966, cable pot heads or joints are likely to fail due to degraded insulation and corroded steel armouring. The probability of a 22kV feeder cable failure is 23%, which has been used for risk cost calculations.

The consequence of a failure of a single 22kV feeder cable at FW would likely be supply interruption to customers on one feeder, but there would be arcing and possible explosive failures occurring with the public streetscape where the feeder cables exit the zone substation.

The expected risk cost for FW feeder cables has been determined as $37,000 per annum.

4.1.4 Protection and control relays and other secondary assets

Condition of electromechanical relays

FW is equipped with approximately 79 protection relays out of which 49 are legacy electromechanical relays. Electromechanical relays are known to mal-operate due to setting drift leading from loss of magnetism. These relays were installed in and around the mid-1960s and will be around 55 years old. These relays have a nominal design life of 40 years.

These legacy relays are used to protect major primary plants within FW including:

- Power Transformers;
- 66kV Buses; and
- 22kV Buses (switchboard, switchgear and bus).

There are three existing issues associated with the secondary assets at FW:

- Condition of the existing Transformer Protection relays;
- Condition of the existing Capacitor Bank protection relays; and
- Condition of the existing 240V, 50V and 24V DC Battery Banks.

Additionally, it should be noted that the secondary assets at FW, such as batteries, chargers and communication equipment, are also in a deteriorated condition, with associated risk to the ability to supply loads in the area. The impact of this supply risk has not been quantified within this appraisal as it is considered to be secondary to the impact of switchgear and relay failure.

Due to the poor condition of the protection relays the probability of failure of a relay is 23%, which has been used in determining the risk cost.

The consequence of a failure of the protection relays at FW would likely be supply interruption from one bus to the entire station.

The expected risk cost for the protection relay system failure has been determined as $37,000 per annum. Due to the age and condition of the assets mentioned above, the risk cost above will continue to increase until the assets are removed from service.

Condition of the DC supply systems

Most batteries at FW are beyond their design life (15 years), have deteriorated and are failing. This is the main issue driving the replacement of the DC system. This is a critical system used to supply auxiliary power to protection relays, control, and communication circuits, and trip/close coils of HV circuit breakers. Failure of the DC system will leave the zone substation unprotected and inoperable, which represents a serious safety risk for the public and personnel, and an increased risk of asset damage and loss of supply to customers, in addition to a negative impact on Jemena's brand and reputation. The most common failure involves a failure of the DC system to supply power. Given that the condition of most batteries has deteriorated and frequent top-up of water is required, the probability of failure is considered to be 20%.

The consequence of a catastrophic failure of a battery bank is the loss of auxiliary supply to critical protection, control and communication equipment, which may require load transfer to other zone substations. The substation could likely be off supply for a minimum of one hour while damage was assessed, any necessary minor repairs undertaken and supply restored.

The expected risk cost for a DC system failure has been determined as $188,000 per annum. Due to the age and condition of the assets mentioned above, the risk cost above will continue to increase until the assets are removed from service.

4.2 Asset capacity

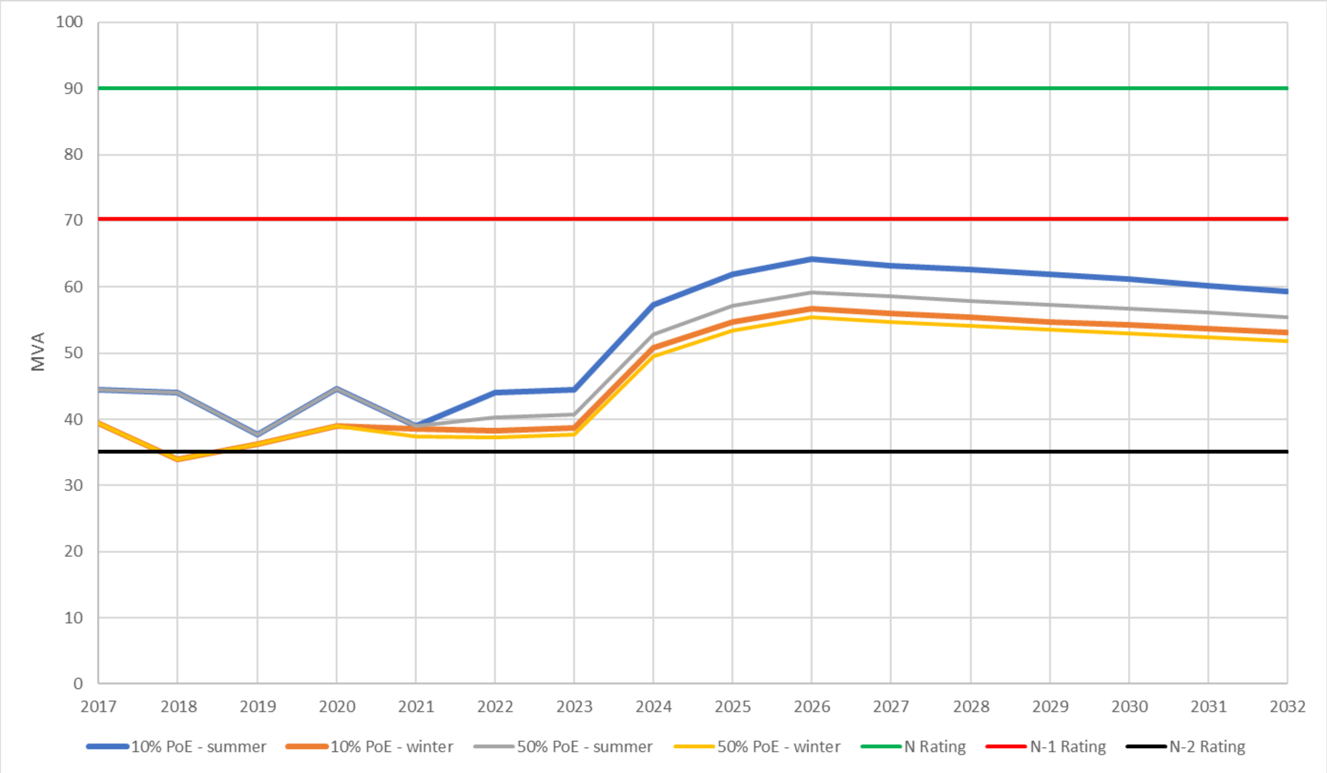
4.2.1 Maximum demand forecasts

The assessment of reliability of supply from available asset capacity in this FPAR is based on Jemena's 2022 maximum demand forecasts.

The maximum demand forecasts for FW are shown below in Figure 4–2. It is noted that maximum demand is forecast to increase rapidly over the next few years as a result of some large customer connections occurring in the FW supply area, on a backdrop of marginally declining underlying maximum demand.

The FW maximum demand is forecast to be 44.4MVA for the summer of 2023 under 10% PoE. By 2032 it is forecast that maximum demand will be approximately 59.4MVA. The highest maximum demand over the 10-year planning horizon is forecast to be 64.3MVA for summer 2026.

Figure 4–2: FW Maximum Demand Forecast and Ratings (MVA)



4.2.2 Substation capacities

The zone substation assets limiting the summer and winter capacity at FW are the 66/22kV power transformers' thermal limits. FW consists of three 66kV/22kV power transformers, two 66kV bus-tie circuit breakers and eight 22kV feeders from three 22kV indoor switchboards. The ratings of the key assets are:

- Three transformers rated at 30MVA continuous each, with a cyclic rating of 35MVA;
- Three 22kV buses each rated at 1,200 Amps (45.7MVA) with space for 4 circuit breakers on each switchboard, of which:
  - 8 are currently used for feeder circuit breakers to supply customers in the FW supply area
  - 2 are used for capacitor banks that provide 9.14MVAr and 14.6MVAr for power factor correction.

The total nameplate rating of the zone substation is 90MVA. The N-1 rating is based on the transformer cyclic rating of 35MVA. With two of the three transformers in service, the N-1 rating is 70MVA.

4.2.3 Transfer capacity

FW has ties to Jemena's adjacent zone substations and has approximately 31.6MVA load transfer capability under contingency conditions. Transfer capacity has been considered in the economic evaluation, having the effect of reducing the EUE risk at FW.

4.3 EUE and safety risk cost summary

The EUE and safety risk costs associated with this demand profile[2] for the failure of FW assets[3], taking into account asset ratings, probability of failure, a five-month repair time and the available transfer capacity, are presented in Table 4–1.

Table 4–1: EUE and Safety Risk Cost ($M, 2022) (Central Scenario)

Year	Safety risk	EUE	Total
2022	3.5	0.0	3.5
2023	4.2	0.0	4.2
2024	4.8	3.6	8.4
2025	5.5	22.7	28.2
2026	6.2	52.6	58.8
2027	6.9	46.9	53.8
2028	7.5	42.2	49.7
2029	8.2	36.0	44.2
2030	8.9	29.0	37.9
2031	9.6	24.1	33.7
2032	10.2	19.0	29.2

For the economic evaluation, the EUE and safety risk costs are assumed to remain at 2032 levels beyond this time.

[2] Using an EUE weighting of 30% for the 10% PoE maximum demand, and 70% for the 50% PoE maximum demand, summer and winter, and the load duration curve for FW.

[3] EUE is dominated by a failure in the bus tie section or a failure which results in the loss of two buses. EUE contribution from the loss of all three buses has not been quantified as it is considered not to be a credible contingency.

5. Screening for non-network options

5.1 Types of non-network options considered

Potential non-network options that could meet the investment objectives (as envisaged in the RIT-D Application Guidelines[4] Section 6.1) are listed below:

- **Demand Management (DM)** – Any measure or program targeted at reducing peak demand, including direct load control, broad-based demand management, or targeted customer demand response programs.
- **Embedded Generation (EG)** – Increased local or distributed generation/supply options, including using the capacity for standby power from existing or new embedded generators, or using energy storage systems and load transfer capacity.

Generation solutions within customer premises or operated within the market could have benefits above the network support benefits that may flow to that customer, improving the economic viability of such solutions.

Customer demand reduction or standby generation solutions are limited by the demand of that customer, i.e., an individual customer can only reduce its demand to zero. Typically, the absence of large customers limits the potential for large demand-side solutions.

Demand composition and customers

At FW, the share of maximum demand from a total of 14,385 customers is forecast to be consuming up to 44.4MVA of coincident net load in summer 2023, comprises of:

- 13,550 residential customers consuming 19.9MVA peak summer load (average 0.0015MVA)
- 805 commercial customers consuming 8.2MVA of peak summer load (average 0.01MVA)
- 30 industrial customers consuming 16.3MVA of peak summer load (average of 0.54MVA).

For FW, the two largest industrial (HV) customers are:

- Customer 1 (Maximum demand -1.7MVA)
- Customer 2 (Maximum demand – 1.4MVA)

Currently, there is no HV-connected embedded generation supplied from the FW zone substation other than the small residential and commercial solar PV. For FW, there are 1,628 solar PV installations with a capacity of 7.0 MW[5].

5.2 Non-network assessment scenarios

The aim of defining potential non-network and SAPS scenarios is to test whether a non-network or SAPS option (or combination of options) is a viable way to avoid or reduce the scale of a network investment in a way that efficiently addresses the identified need. A non-network or SAPS option may comprise a single non-network measure (e.g., installation of renewable or embedded energy generation) or a combination of measures (e.g., generation plus demand management).

[4] AER Application Guidelines RIT-D (August 2022).

[5] As at 16th November 2022.

Potential non-network and SAPS scenarios for FW are:

- Meeting the identified need in its entirety through a non-network or SAPS option allows all of the poor-condition assets at FW to be retired.
- Replacing one switchboard, one transformer and the associated protection and control relays at FW providing 30MVA of capacity, with the residual need (i.e. from the remaining in-service poor condition assets) addressed through a non-network option.
- Replacing two switchboards, two transformers and the associated protection and control relays at FW providing 60MVA of capacity, with the residual need (i.e. from the remaining in-service poor condition assets) addressed through a non-network option.
- Replacing three switchboards, three transformers and the associated protection and control relays at FW providing 90MVA of capacity, with no non-network options, allowing all of the poor condition assets at FW to be replaced.

A non-network or SAPS option would need to supply the forecast maximum summer load at FW over the 10-year planning horizon of 64 MW. This would allow all of the assets in poor condition to be retired. A non-network solution supplying 31 MW may be feasible if used in conjunction with part of a network asset replacement option. Smaller non-network or SAPS solutions would not provide sufficient capacity to be credible options.

The option screening criteria is applied in the next section.

5.2.1 Scenario 1 – Non-network or SAPS option to meet the identified need in its entirety

A viable generation option that meets the maximum demand at FW of 64MVA, that reliably meets customer requirements in an N-1 situation requires:

- two generators each able to supply 64 MWp;
- three generators each able to supply 32 MWp; or
- 'N' generators each able to supply 64 MWp ÷ (N-1).

This would enable the system to meet maximum demand in an N-1 situation (i.e. one generator out of service). Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

The costs of this scenario are likely to exceed those of the preferred network option. For example, the EPC capital cost of a small gas-fired generator is approximately $1.25M per MW[6].

For two 64 MW generators, the cost will be over $160M, excluding land, connection and operating costs. Note, this does not allow for some reduction in generator capacity if the solution is complemented with other non-network demand management and efficiency measures, which could provide a lower cost.

This would lead to a much higher marginal cost to the customer compared to a network solution cost of approximately $40.6M, being the capital cost of the replacement of all three switchboards, transformers and secondary equipment.

Additionally, the maximum demands of individual customers indicate that no potential existing customer-owned generation would be large enough to meet the need.

5.2.2 Scenario 2 – Non-network option and replace one switchboard and one transformer

If only one switchboard, one transformer and related protection relay assets were replaced providing the network capacity equivalent to one transformer (30MVA), a viable, non-network would be required to supply enough power,

[6] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

and/or enable a sufficient reduction in demand, to supply the peak load should the single transformer or switchboard combination fail.

A viable generation option that meets the maximum demand at FW of 64MVA, that reliably meets customer requirements in an N-1 situation requires:

- two generators each supplying 32 MWp; or
- three generators each supplying 22 MWp; or
- 'N' generators each supplying 64 MWp ÷ (N).

This would enable the system to meet maximum demand in an N-1 situation (i.e. one generator or one power transformer out of service). Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

This is likely to cost at least $80M, excluding land, connection and operating costs. Note, this does not allow for some reduction in generator capacity if the solution is complemented with other non-network demand management and efficiency measures, which could provide a lower cost.

This would lead to a much higher marginal cost to the customer compared to a network solution cost of approximately $30.0M, being the incremental capital costs of the avoided replacement of the remaining two switchboards, transformers and secondary equipment.

5.2.3 Scenario 3 – Non-network option and replace two switchboards and two transformers

The most realistic scenario for a non-network option making a potentially credible contribution to meeting the identified need is where it allows for a reduced level of investment below the network option of replacing three switchboards and the associated relay assets.

Accordingly, Jemena considered the potential credibility of non-network options for covering the gap when only two switchboards and transformers are replaced at FW so it has a new configuration of two switchboards and two transformers with an N-1 capacity of 33MVA. With this reduced investment (and no permanent load transfers) a non-network option would need to cover for the failure of a transformer or one of the switchboards. This would leave a shortfall of 64MVA – 33MVA = 31MVA.

A viable generation option that meets the maximum demand at FW of 64MVA, that reliably meets customer requirements in an N-1 situation requires:

- one generator supplying 31 MWp;
- two generators each supplying 15 MWp; or
- 'N' generators each supplying 31 MWp ÷ (N).

This would enable the system to meet maximum demand in an N-1 situation (i.e. one generator or one power transformer out of service). Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

This is likely to cost at least $39M, excluding land, connection and operating costs. Note, this does not allow for some reduction in generator capacity if the solution is complemented with other non-network demand management and efficiency measures, which could provide a lower cost.

This would lead to a much higher marginal cost to the customer compared to approximately $20.0M, being the incremental capital costs of the avoided replacement of the remaining switchboard, transformer and secondary equipment at FW.

5.3 Assessment approach and findings

This section reports on the credibility of potential non-network options as alternatives or supplements for the Footscray West replacement works. The criteria used to assess the potential credibility were:

- **Addressing the identified need**: reducing or eliminating the safety and supply reliability risk associated with the assets in poor condition.
- **Being technically feasible**: there are no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Commercially 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.

Table 5–1 shows the rating scale applied for assessing non-network options.

Table 5–1: Assessment Criteria Rating

Rating	Colour Coding
Does not meet the criterion	Red
Does not fully meet the criterion (or uncertain)	Amber
Clearly meets the criterion	Green

The assessment has also considered whether a non-network or SAPS option (or combination of non-network measures) is a viable way to avoid or reduce the scale of a network investment in a way that meets the identified need. A non-network option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

Table 5–2 shows the initial assessment of non-network and SAPS options against the RIT-D criteria. The assessment did not find any of the non-network or SAPS options to be potentially credible against RIT-D criteria (considered both in isolation and in combination with network solutions). The assessment commentary for each of the generation and storage options is set out in the following sections.

Table 5–2: Assessment of Non-network Options against RIT-D Criteria

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and Storage				
1.1 Gas turbine power station				
1.2a Generation using renewables (Solar)				
1.2b Generation using renewables (Wind)				
1.3 Dispatchable generation (large customer)				
1.4 Large customer energy storage				
2.0 Demand management				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Broad-based demand response				
2.4 Targeted demand response				

5.4 Non-network assessment commentary

5.4.1 Generation and storage

The assessment rationale for each of the generation and storage options is as follows:

- **Gas turbine power station (1.1):**

Identified need – Reduces risks of running poor condition assets beyond their end of life. Capable of meeting the identified need by providing multiple gas turbine generators (met).

Technical - Significant constraints and barriers to deployment of equipment to generate up to 64 MW in a dense urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). In addition, we cannot establish the availability of a suitable high-pressure gas pipeline in the locality that is essential for this type of generation (not met).

Commercial – Costs of this type of generation appear much higher than the network alternatives even before land, connection and operating costs are included, as detailed in the scenarios of Section 5.2. We note that non-network proponents rather than Jemena would bear the cost of these additions and they would recoup these costs through selling power generated (and other services) through the market. The scale of estimated capital costs illustrates the quantum of additional capital costs compared to a network solution and this will lead to a much higher cost per MWh compared to the preferred network solution (not met).

Timing - Planning process and nature of the investment and likely objectives, together with design requirements (both for the generators, gas connections and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall – not a potentially credible option.

- **Generation using renewables solar (1.2a):**

Identified need - Reduces risks of running poor condition assets beyond their end of life. Unlikely to meet or meaningfully contribute to the identified need. Generation of 31 MW (the minimum required for a viable non-network option) using solar PV is likely to require more than 100 acres of land[7]. Devoting this amount of land to energy production in a dense, urban environment is unlikely to be feasible. As noted in Section 5.1, solar PV installations in FW provide a relatively small capacity of 6.7 MW. In addition, the generation profile of solar power may not align with the consumption profile of consumers, requiring either an overbuild of generation or complementing storage (not met).

Technical – While it is technically feasible to use this well-understood and applied technology for this type of power generation, there are significant constraints to the deployment of a solar PV facility to generate 31 MW in this locality. These include zoning, planning and environmental constraints (given the land requirements), and the lack of evidence of the availability of more than 100 acres for this type of purpose (not met).

Commercial – Costs of this type of generation are unlikely to be commercially viable or comparable with the costs of network alternatives if the generation profile is required to support the demand profile, requiring substantial amounts of storage to support the installation. Furthermore, the costs in the Footscray environment of purchasing up to 100 acres of land are likely to be significant. This is unlikely to be cost-effective when compared with the network alternatives (not met).

Timing - Planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall – not a potentially credible option.

- **Generation using renewables wind (1.2b)**

Identified need—Reduces risks of running poor condition assets beyond their end of life. Unlikely to meet or meaningfully contribute to the identified need. Based on a 2 MW wind turbine requiring 1.5 acres of land[8], a 31 MW wind farm would require 24 acres. Utilising this amount of land for a wind farm with tall turbines in a dense, urban environment is unlikely to be feasible (not met).

Technical—It is unclear whether there is an adequate site available in terms of elevation, and wind conditions for wind generation (for example). The planning constraints and environmental factors involved in securing planning permission for using land for this purpose are very significant and the use of land for this purpose is unlikely to be allowed. (not met).

Commercial—The cost of acquiring land and installing wind turbines is likely to significantly exceed the costs of the preferred network solution, which means this form of generation is unlikely to be viable. Storage may also be needed to cater for the intermittency of wind (not met).

Timing— Planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall—not a potentially credible option.

- **Dispatchable generation (large customer) (1.3)**

Identified need— Reduces risks of running poor condition assets beyond their end of life. There are 30 industrial customers consuming 16.3MVA at the summer peak and 805 commercial customers consuming 8.2MVA. As noted in Section 5.1 there are only two large industrial (HV) customers with maximum demands of 1.7MVA and 1.4MVA. It's unlikely that a small number of industrial customers is consuming sufficient energy for this type of generation to provide a viable non-network option. The practical difficulties of coordinating generation efforts for a large number of small consumers are too great for this to be viable. Jemena believes low levels of connections for larger embedded generators are due to a reflection of the nature of Jemena's network, which services the northeast of greater metropolitan Melbourne, where there is limited availability of physical space for significantly

[7] https://www.quora.com/How-much-land-is-required-to-setup-a-1MW-solar-power-generation-Unit-1

[8] https://sciencing.com/much-land-needed-wind-turbines-12304634.html

sized embedded generators. Instead, there is a preference for smaller-scale embedded generation, particularly rooftop solar PV, for which Jemena has seen an ongoing increase in installed capacity on its network (not met).

Technical—This type of generation is technically feasible within existing industrial sites but would face planning and technical constraints (not fully met).

Commercial—The estimated cost of a relatively small generator (4MVA) is about $3.9M and 6.5MVA about $5.6M both excluding installation and operating costs. To provide the minimum 31MW needed, 5 to 8 of these would be required. This is unlikely to be commercially viable and too large for customers connected within the 22kV distribution network of FW, given the much lower costs of providing this capacity using a network solution (not met).

Timing—Planning processes, the nature of the investment and likely obstacles, together with design requirements (both for generators and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall—not a potentially credible option.

- **Large customer energy storage (1.4)**

The responses to this option (1.4) are similar to option 1.3. The overall finding that this is not a potentially credible option is driven by the relatively small power requirements per industrial customer and the need to coordinate efforts across many power users – this is likely to be time-consuming and difficult to achieve. In addition, the costs associated with battery storage to manage peak demand and therefore reduce the scope of the non-network project are likely to be high compared with the marginal costs for a full network solution.

Overall—not a potentially credible option.

5.4.2 Demand management/efficiency

The assessment rationale for the demand management/efficiency options is as follows:

- **Customer power factor correction (2.1)**

Identified need—This option cannot address the identified need because FW operates close to unity power factor, even at maximum demand. Therefore further reactive power compensation will provide no reductions in demand (not met).

Technical—This type of saving is technically feasible for industrial users on a certain type of contract and is achievable (fully met).

Commercial—This could be cost-effective (fully met).

Timing—This option could be completed by 2025 (fully met).

Overall—not a potentially credible option.

- **Customer solar power systems (2.2)**

Identified need— Reduces risks of running poor condition assets beyond their end of life. Solar PV customer premises penetration in Jemena is approaching 15%. For the FW supply area, 1,559 of 14,385 customers (11%) have a solar PV system installed. Approximately 6,200 additional FW customers (54%) would need to have a 5kW solar PV system installed to provide 31 MW capacity. Currently, as noted in Section 5.1, solar PV installations in FW provide a relatively small capacity of 6.7 MW. This rate of take-up is not considered to be achievable (not met).

Technical—This option is technically feasible and the technology is well understood and tested (fully met).

Commercial— Achieving a greater than average solar PV take-up would require a financial incentive and achieve the level of take-up for this option to be potentially credible would require a very high subsidy (not fully met). The systems are also likely to require storage to be able to support late afternoon and early evening demands, reducing the commercial viability of this solution (not fully met).

Timing—This option could be completed by 2025 but there is uncertainty given the large number of customers that would need to install solar PV (not fully met).

Overall—not a potentially credible option.

- **Broad-based demand response (2.3)**

Identified need—The assessment for this option is similar to the results for Option 2.2. Each of Jemena's customers would have to reduce consumption by approximately 48% for the summer peak to achieve a 31MVA reduction (31MVA/64MVA = 48%). This scale of reduction (in magnitude and for every customer) is considered unrealistic even if accompanied by subsidies to consider doing this (not met).

Technical—This option is not technically feasible given the size of the demand reduction required and the number of customers needing to participate (not met).

Commercial—Unclear that this is commercially feasible, as the payments to customers could be substantial to achieve such high levels of demand reduction. (not fully met).

Timing—This type of mass action would be difficult to promote and implement by 2025 (not fully met).

Overall—not a potentially credible option.

- **Targeted demand response (2.4)**

This option has a similar assessment profile to options 1.3 and 1.4. All essentially rely on the actions of a small number of high-consumption users. There is no evidence of a small number of very large users who might be persuaded to curtail load and hence this is unlikely to meet the identified need. We also do not think this is likely to be commercially feasible or achievable within the intended timing of the network solution.

Overall—not a potentially credible option.

6. Network options considered in the RIT-D

This section outlines the credible options that have been considered in the RIT-D and the proposed works associated with each credible option. The base case is established, to compare the options identified.

6.1 "Do nothing" option (base case)

The assessment of credible options is based on a cost-benefit analysis that considers the future EUE reliability of supply and safety risk cost of each credible option compared with the base case, where no additional investment is implemented.

The base case is presented as a do-nothing option (Option 1), where Jemena would continue to manage the network assets through to failure using existing maintenance practices, with involuntary load shedding and the safety consequences which may arise from each unplanned asset failure.

6.2 Network options

Jemena has identified three network options (in addition to the base case) that attempt to address the identified need:

- Option 2 – Replace one switchboard, one transformer and their relays at FW;
- Option 3 – Replace two switchboards, two transformers and their relays at FW; and
- Option 4 - Replace all three switchboards, three transformers and their relays at FW.

Each network option has two variants:

- Option 'a' – In-situ: replace poor condition assets; new assets in the same switchyard location; and
- Option 'b' – Rebuild: retire poor condition assets; new assets established in a vacant area of the switchyard.

7. Submissions to the DPAR

This section summarises the submissions received on the Non-Network Options Screening Report Notice of determination and the DPAR.

A RIT-D Stage 1: Non-Network Options Screening Report Notice of determination, published on Jemena's website on 11 October 2022, was prepared to establish whether the currently proposed network solution to address the need, could be changed in scope or otherwise altered in response to a non-network or SAPS solution.

A RIT-D Stage 2: Draft Project Assessment Report, published on Jemena's website on 26 October 2022, was prepared to present the economic evaluation of the credible options and to identify the proposed Preferred Option.

There were no submissions received on either Stage 1 or Stage 2 reports during the RIT-D consultation.

8. Market benefit assessment methodology

This section outlines the methodology that Jemena has applied in assessing the market benefits associated with each of the credible options considered in this RIT-D. It describes how the classes of market benefits have been quantified and outlines why particular classes of market benefits are considered inconsequential to the outcome of this RIT-D.

It also describes the reasonable scenarios considered in comparing the base case ‘state of the world’ to the credible options considered.

8.1 Market benefit classes quantified for this RIT-D

The RIT-D has been assessed over a twenty-year period. Market benefits for the first ten years (2023-2032) were based on Jemena’s 2022 maximum demand forecasts. Following on, all market benefits are held constant at 2032 levels for the rest of the appraisal period. This section outlines the classes of market benefits that Jemena considers will have a material impact on this RIT-D and have therefore quantified.

The classes of market benefits quantified for this RIT-D include changes in:

- involuntary load shedding and customer interruptions including reduced safety risk costs; and
- changes in load transfer capacity and the capacity of embedded generators to take up load.

8.1.1 Involuntary load shedding and customer interruptions

Involuntary load shedding is where a customer’s load is interrupted (switched off or disconnected) from the network without their agreement or prior warning. Involuntary load shedding can occur unexpectedly due to a network outage event, or pre-emptively to maintain network loading to within asset capabilities. The aim of a credible option, such as demand side management or a network capacity augmentation, is to provide a change in the amount of involuntary load shedding expected.

A reduction in involuntary load shedding, relative to the Base Case, results in a positive contribution to the market benefits of the credible option being assessed. The involuntary load shedding of a credible option is derived by:

- The quantity (in MWh) of involuntary load shedding required assuming the credible option is completed.
- The value of customer reliability (in $/MWh).
- Jemena forecasts and models hourly load for the forward planning period and quantifies the EUE (involuntary load shedding) by comparing forecast load to network capabilities under system normal and network outage conditions.
- Jemena has captured the reduction in involuntary load shedding as a market benefit of the credible options assessed in this RIT-D.

Avoided safety risk costs relate to asset failures that affect the safety of employees and the public. Safety risk costs have been estimated on three main factors, the consequence of a severe safety event, the probability of exposure of people to a severe adverse event at FW, and the probability of asset failure.

8.1.2 Changes in load transfer capacity and embedded generators

Jemena has assessed the potential for customers to use standby and standalone generation and/or storage solutions in the FW supply area. This assessment showed there was insufficient potential for generation or storage to materially address the need.

However, the FW supply area does have material levels of load transfer capacity to adjacent supply areas that can reduce the reliability impacts of an asset failure at FW. This has been included in the analysis and reduces the EUE. However, this transfer capacity does not impact the safety risk costs.

8.2 Market benefit classes not relevant to this RIT-D

This section outlines the classes of market benefits that Jemena considers immaterial to this RIT-D assessment and our reasoning for their omission from this RIT-D assessment. The market benefits that Jemena considers will not materially impact the outcome of this RIT-D assessment include changes in:

- timing of expenditure;
- voluntary load curtailment;
- costs to other parties;
- option value; and
- electrical energy losses.

8.2.1 Timing of expenditure

Jemena has assessed the timing of other unrelated expenditure is not impacted by the options considered in this assessment. Therefore, this market benefit was not quantified as it was not considered to be relevant to differentiate between options that address the need in the FW supply area.

8.2.2 Voluntary load curtailment

Voluntary load curtailment is where a customer/s agrees to voluntarily curtail their electricity under certain circumstances, such as high network loading or during a network outage event. The customer will typically receive an agreed payment for making load available for curtailment, and for actually having it curtailed during a network event. A credible demand-side reduction option leads to a change in the amount of voluntary load curtailment.

An increase in voluntary load curtailment, compared to the base case, results in a negative contribution (a cost) to the market benefits of the credible option.

Jemena has assessed the potential for voluntary load curtailment in the FW area. This assessment showed there was minimal potential for voluntary load curtailment to provide sufficient additional capacity to either replace a network solution or to enable a more economic network solution. Therefore, this market benefit was not quantified as it was considered to be not material to differentiate between network options.

8.2.3 Cost to other parties

There are no market benefits associated with reduced costs to other parties in this instance.

8.2.4 Option value

The AER RIT-D guidelines explain that *“option value refers to a benefit that results from retaining flexibility in a context where certain actions are irreversible (sunk), and new information may arise in the future as a payoff from taking a certain action. We consider that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change”*.

In the context of the FW supply area, it is noted that the primary need has been identified as a safety need. As explained in Section 3.1, a credible solution must enable the retirement of the poor-condition assets at FW.

It is therefore considered that in this case, there is little value in retaining flexibility, given that the safety need requires decommissioning of the existing assets at FW. Jemena has therefore not attempted to estimate any additional option value market benefit for this RIT-D assessment.

8.2.5 Electrical energy losses

Reducing network utilisation, through network impedance or load changes in the FW supply area could result in a change in network losses. However, the network options are all expected to only marginally reduce network losses and all to a similar degree.

The consideration of electrical energy losses would not change the rankings of the options. Therefore, the market benefits associated with electrical energy losses are considered immaterial to the result of this RIT-D and have therefore been excluded from the market benefit assessments.

8.3 Sensitivities

Jemena has critically assessed the parameters and determined the key variables applied in valuing the economic benefits including:

- maximum demand growth rate;
- value of customer reliability (VCR);
- capital costs;
- discount rate; and
- asset failure rate.

To test the robustness of the cost-benefit analysis to changes in key variables from the base case, the following sensitivities have been tested.

8.3.1 Maximum demand growth rate

A range of +10% to -20% of the base case forecast maximum demand has been applied to the sensitivity studies for this RIT-D.

8.3.2 Value of customer reliability

The cost of EUE is calculated using the VCR. This is an estimate of how much value electricity consumers place on a reliable electricity supply. In assessing the credible options to alleviate the impact of limitations on its network, Jemena has applied VCR values based on the AER's Values of Customer Reliability Review[9] published in December 2019. Therefore, the composite VCR for FW has been derived as shown in Table 8–1, escalated by CPI to 2022.

Table 8–1: Base Case VCR for FW

Sector	AER VCR ($/kWh)	Annual Energy consumption (%)	Energy Consumption weighted VCR ($/kWh)
Residential[10]	21.25	32	6.80
Agricultural	37.87	0	0.00
Commercial	44.52	47	20.92
Industrial	63.79	21	13.40
Composite of all sectors			41.12
Composite of all sectors (indexed to 2022)			**44.62**

[9]Australian Energy Regulator 2019, Values of Customer Reliability Final Report on VCR values, December 2019

[10] Climate zone 6, CBD and Suburban.

Sensitivities to the base VCR of ±20% have been considered.

8.3.3 Capital costs

The base case network project capital costs have been estimated by Jemena's internal estimation teams. Consideration has been given to recent similar augmentation projects and expected costs based on site-specific construction complexities and industry experience. These project estimates have been prepared for planning purposes and are therefore subject to an estimated range of ±30%, which has therefore been applied to the sensitivity studies for this RIT-D. Costs include disposal of the old plant and scrap value where appropriate.

8.3.4 Discount rate

A base case discount rate of 5.50%[11] has been applied in assessing the Net Present Value (NPV) assessment of credible options. This includes return on and of capital and an assumed 1% of capital cost per annum for additional O&M. Sensitivities to the base discount rate have been considered as summarised in Table 8–2.

8.3.5 Asset failure rate assumptions

The base case failure rates assumed in the analysis are set out in Section 4.1. Sensitivities to the failure rates of ±30% have been considered.

8.3.6 Summary of sensitivity assumptions

Table 8–2 summarises the sensitivities of key variables tested in this FPAR.

Table 8–2: Sensitivity Assumptions

Sensitivity	Lower bound	Base Case	Higher bound
Maximum demand forecast	80%	100%	110%
Value of customer reliability	80%	100%	120%
Capital cost	70%	100%	130%
Discount rate	2.27%[12]	5.50%	8.73[13]
Asset failure rate	70%	100%	130%

8.4 State of the world scenarios

RIT-D assessments are required to be undertaken using cost-benefit analysis that includes an assessment of 'reasonable scenarios', which are designed to take into account the uncertainty associated with different future states of the world when identifying the preferred option. The weighting of scenarios is used to manage the risk associated with the uncertainty of future benefits.

[11] Discount rate is based on an indicative commercial discount rate from AEMO 2021 Inputs, Assumptions and Scenarios Report, dated July 2021, Table 30. https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en

[12] The most recent WACC of a network business. Real, pre-tax WACC from AER Final Decision for AusNet Services Transmission Determination 2022-27, January 2022, Table 3.1. https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20AusNet%20Services%20transmission%202022-27%20-%20Attachment%203%20-%20Rate%20of%20return%20-%2028%20January%202022.pdf

[13] A symmetrical adjustment upwards

Jemena has adopted three future state-of-the-world scenarios, each weighted as follows:

- Low scenario – credible changes to key assumptions that result in the lowest NPV.
- Central scenario – the base case assumptions adopted (i.e., the most likely scenario).
- High scenario – credible changes to key assumptions that result in the highest NPV.

The key assumptions in the analysis that have relatively high uncertainty in the future are maximum demand and the asset failure rate of poor-condition assets which determine the EUE and safety risk costs.

Table 8–3: Scenarios

Scenario	Low Scenario	Central Scenario	High Scenario
Weighting	**25%**	**50%**	**25%**
Maximum Demand	80%	100%	110%
Asset Failure Rate	70%	100%	130%

9. Options analysis

This section presents the base case limitation and summarises the analysis results of credible options. The net economic benefit analysis has been assessed considering the network risk and expected costs for the twenty years from 2023 to 2043.

Each credible option has been ranked according to its net economic benefit, which is the difference between the market benefit and the costs within the assessment period (present value).

9.1 Option 1 – Do nothing

This option considers the impact of a 'Do Nothing' base case, which would include no additional investment in FW (beyond any previously committed investment). Involuntary load shedding may result from unplanned asset failures and associated safety risk consequences. The impact of these network limitations under the base case is presented in Table 9–1 below.

Table 9–1: Do Nothing – PV Cost of EUE and Safety Risk ($M, 2022)

Option 1	Low Scenario	Central Scenario	High Scenario	Weighted Total
EUE Cost	1.5	303.8	2129.6	684.7
Safety Risk Cost	68.2	97.4	126.6	97.4
Total Cost	**69.7**	**401.2**	**2256.3**	**782.1**

The capital cost of this option is assumed to be zero, with the cost of unplanned asset failure represented by the value of EUE and the safety risk cost.

9.2 Option 2 – Replace one transformer, switchboard and associated relays

Option 2 involves replacing one switchboard, one transformer and their associated protection and control relays at FW, leaving the remaining assets run to failure, with the residual cost of unplanned asset failure represented by a lower value of EUE and safety risk cost compared to Option 1.

Table 9–2: Option 2 – PV Cost of EUE and Safety Risk ($M, 2022)

Option 2	Low Scenario	Central Scenario	High Scenario	Weighted Total
EUE Cost	0.8	151.9	1064.8	342.4
Safety Risk Cost	45.7	65.3	84.9	65.3
Total Cost	**46.5**	**217.2**	**1149.7**	**407.7**

The capital cost of Option 2a is approximately $22.0M ($2022 real) for an in-situ replacement with an ongoing operating cost of $0.2M pa. The capital cost of Option 2b is approximately $20.0M ($2022 real) for a rebuild of FW with an ongoing operating cost of $0.2M pa.

9.3 Option 3 – Replace two transformers, switchboards and associated relays

Option 3 involves replacing two switchboards, two transformers and their associated protection and control relays at FW, leaving the remaining assets run to failure, with the residual cost of unplanned asset failure represented by a lower value of EUE and safety risk cost compared to Option 2.

Table 9–3: Option 3 – PV Cost of EUE and Safety Risk ($M, 2022)

Option 3	Low Scenario	Central Scenario	High Scenario	Weighted Total
EUE Cost	0.0	0.0	0.0	0.0
Safety Risk Cost	22.5	32.1	41.8	32.1
Total Cost	**22.5**	**32.1**	**41.8**	**32.1**

The capital cost of Option 3a is approximately $32.0M ($2022 real) for an in-situ replacement with an ongoing operating cost of $0.3M pa. The capital cost of Option 3b is approximately $30.0M ($2022 real) for a rebuild of FW with an ongoing operating cost of $0.3M pa.

9.4 Option 4 – Replace all three transformers, switchboards and associated relays

Option 4 involves replacing all three switchboards, transformers and their associated protection and control relays at FW, resulting in zero residual EUE and safety risk cost.

Table 9–4: Option 4 – PV Cost of EUE and Safety Risk ($M, 2022)

Option 4	Low Scenario	Central Scenario	High Scenario	Weighted Total
EUE Cost	0.0	0.0	0.0	0.0
Safety Risk Cost	0.0	0.0	0.0	0.0
Total Cost	**0.0**	**0.0**	**0.0**	**0.0**

The capital cost of Option 4a is approximately $42.2M ($2022 real) for an in-situ replacement with an ongoing operating cost of $0.4M pa. The capital cost of Option 4b is approximately $40.6M ($2022 real) for a rebuild of FW with an ongoing operating cost of $0.4M pa.

9.5 Net economic benefits

The economic analysis shown in Table 9–5, based on the scenario weightings, demonstrates that Option 4b provides the highest present value of net economic benefits.

Table 9–5: Cost-Benefit Analysis ($M, 2022) – Weighted Scenarios

Option	Capital cost	PV of capital and O&M costs	PV of EUE and safety risk costs	PV of benefits	NPV	Ranking
Option 1 - Do Nothing	(0.0)	(0.0)	(782.1)	0.0	0.0	7
Option 2a - Replace one transformer, switchboard and associated relays in-situ	(22.0)	(23.6)	(407.7)	374.5	350.8	6
Option 2b - Replace one transformer, switchboard and associated relays as a rebuild of FW on site	(20.0)	(21.4)	(407.7)	374.5	353.0	5
Option 3a - Replace two transformers, switchboards and associated relays in-situ	(32.0)	(34.5)	(32.1)	750.0	715.5	4

Option	Capital cost	PV of capital and O&M costs	PV of EUE and safety risk costs	PV of benefits	NPV	Ranking
Option 3b - Replace two transformers, switchboards and associated relays as a rebuild of FW on site	(30.0)	(32.3)	(32.1)	750.0	717.7	3
Option 4a - Replace all three transformers, switchboards and associated relays in-situ	(42.2)	(45.8)	(0.0)	782.1	736.3	2
Option 4b - Replace all three transformers, switchboards and associated relays as a rebuild of FW on site	**(40.6)**	**(43.8)**	**(0.0)**	**782.1**	**738.3**	**1**

9.6 Sensitivity Analysis

A set of sensitivities were defined in section 8.3 to test the robustness of the NPV of the central scenario to changes in key assumptions. The sensitivity analysis demonstrated that the conclusions were not sensitive to the changes, as the ranking of the options remained constant as shown in Table 9–6 and Table 9–7 below.

Table 9–6: NPV of Net Economic Benefits ($M, 2022) – Lower Bound Sensitivity (Central Scenario)

Sensitivity	Option 2a	Option 2b	Option 3a	Option 3b	Option 4a	Option 4b	Ranking
Nil	**160.4**	**162.6**	**334.6**	**336.8**	**355.4**	**357.4**	**1**
MD forecast	9.6	11.8	33.0	35.2	53.8	55.8	1
VCR	130.0	132.2	273.9	276.1	294.7	296.6	1
Capital cost	167.5	169.0	345.0	346.5	369.2	370.5	1
Discount rate	216.4	218.7	447.8	450.1	481.0	482.9	1
Failure rates	105.3	107.5	223.9	226.1	235.1	237.1	1

Table 9–7: NPV of Net Economic Benefits ($M, 2022) – Higher Bound Sensitivity (Central Scenario)

Sensitivity	Option 2a	Option 2b	Option 3a	Option 3b	Option 4a	Option 4b	Ranking
Nil	**160.4**	**162.6**	**334.6**	**336.8**	**355.4**	**357.4**	**1**
MD forecast	827.6	829.8	1669.0	1671.2	1689.8	1691.8	1
VCR	190.7	193.0	395.4	397.6	416.2	418.1	1
Capital cost	153.3	156.2	324.3	327.2	341.7	344.2	1
Discount rate	122.4	124.5	257.6	259.8	270.5	272.5	1
Failure rates	215.5	217.7	445.2	447.4	475.7	477.7	1

9.7 Preferred option optimal timing

The optimal timing of the preferred option 4b occurs when its annualised cost exceeds the combined annual cost of the avoided EUE and the safety risk of option 1 (do nothing).

The annualised cost of option 4b is approximately $2.6 million per annum. This is exceeded by the cost of the avoided EUE and safety risk in 2023 under all scenarios as shown in Table 9–8.

Table 9–8: Cost of Avoided EUE and Safety Risk under the Preferred Option ($M, 2022)

Year	Low Scenario	Central Scenario	High Scenario	Weighted Total
2023	2.9	4.2	5.5	4.2
2024	3.4	8.5	45.7	16.5
2025	4.0	28.2	153.9	53.6
2026	4.8	58.8	255.3	94.4
2027	5.2	53.8	249.3	90.5

Taking into account a 2-year lead time for implementation of option 4b, the optimal completion date is by 2025.

10. Conclusion and next steps

The assessment outlined within this report shows that the primary limitations associated with the FW supply area are the concerns around the safety of the deteriorating, poor-condition assets within FW and the level of supply reliability provided by those assets.

10.1 Preferred option

The preferred option is Option 4b as it is the option that maximises the present value of net market benefits, and is the only option that fully addresses the identified need. Other options leave some residual safety and reliability of supply risk from the base case. Option 4b satisfies the requirements of the RIT-D.

The preferred option involves replacing all three transformers, switchboards and associated protection relays by rebuilding FW within the existing FW site at a capital cost of $40.6 million (real $2022), with a completion date of 2025, allowing all of the existing poor condition assets at FW to be decommissioned. As a part of this option, the following major assets will be installed:

- A new outdoor 66kV yard with two 66kV overhead line entries, two sets of 66kV post voltage transformers (VTs), 66kV feeder and bus tie circuit breakers and 66kV disconnectors and earth switches;
- Three 66/22kV 20/33MVA power transformers;
- Three 22kV switchboards installed in separate portable buildings;
- An arc suppression coil with a bypass circuit breaker, and a neutral earthing resistor;
- Protection, control and communications; and
- New feeder exit cables to the first 22kV cable head pole on the distribution network.

10.2 Next steps

This FPAR concludes the RIT-D consultation process for the Footscray West Zone Substation (FW) Transformer, Switchgear and Relay Condition Risk.

In accordance with clause 5.17.5 of the NER, within 30 days of the date of publication of this FPAR, any party disputing the conclusion made in this FPAR should give notice of the dispute in writing setting out the grounds for the dispute (the dispute notice) to the AER.

Jemena will proceed to implement the preferred option if there are no dispute notices within 30 days of the FPAR publication date.

11. Appendix A – Checklist of compliance clauses

Table 11–1 presents a checklist of the NER clause 5.17.4 (j) and references the section within this FPAR where those clauses are addressed.

Table 11–1: Compliance Clauses Checklist

Clause	Section
(1) a description of the identified need for the investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RITD proponent considers reliability corrective action is necessary);	4
(3) if applicable, a summary of, and commentary on, the submissions on the options screening report;	5
(4) a description of each credible option assessed;	6
(7) a detailed description of the methodologies used in quantifying each class of cost and market benefit;	8.1
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;	8.2
(5) where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;	9
(6) quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	9
(9) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	9.5
(10) the identification of the proposed preferred option;	10.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) the indicative capital and operating cost (where relevant); (iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent; and	10.1
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed	10.2