# Jemena Electricity Networks (Vic) Ltd

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

RIT- D Stage 2: Draft Project Assessment Report

Public

13 December 2019

**An appropriate citation for this paper is:**

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



### Authorisation

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### History

| Rev No | Date | Description of changes | Author |
|---|---|---|---|
| 1 | 09/12/2019 | Initial Document | Manoj Ghimire |

### Owning Functional Area

| | |
|---|---|
| Business Function Owner: | Asset Management Electrical |

### Review Details

| | |
|---|---|
| Review Period: | N/A |
| NEXT Review Due: | N/A |

# EXECUTIVE SUMMARY

Jemena Electricity Networks (Vic) Ltd (Jemena) 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 benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

This Draft Project Assessment Report (DPAR) presents the analysis of risk for the Footscray West Zone substation and outlines how this risk has been quantified. It outlines possible options for economically mitigating supply risks and identifies the preferred option to manage the forecast supply risk and reduce safety risks in the area.

This Footscray West Zone substation Regulatory Investment Test for Distribution (RIT-D) DPAR:

- Utilises Jemena's 2019 load demand forecasts;
- Reports on a range of options for managing risk in the network; and
- Reflects on the potential for hybrid network/non-network credible options as assessed within the RIT-D Stage 1: Non-Network Options Screening Report published on Jemena's website.

## Identified need

The condition of the 22kV switchgear and protection relays at Footscray zone substation (FW) is poor. There is an unacceptable risk of failure with potential adverse consequences both for staff safety, and the reliability of electricity supply to Jemena customers. The need to remove the asset from service has been demonstrated.

The most urgent concern for Jemena is the evidence of escalating partial discharges from the switchgear, and the threat this poses to staff safety and customer reliability. Replacing the aged switchgear from service is a priority task for 2021.

Jemena has confirmed the Footscray Zone Substation 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 equipment failure (Safety); and,
- Secondly, the need to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network now (Reliability).

## RIT-D Process

Distribution businesses are required to go through the Regulatory Investment Test for Distribution (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 National Electricity Market (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.

As required by the RIT-D process Jemena considered the credibility of potential non-network options as alternatives or supplements for the FW substation improvement works. A RIT-D Stage 1: Non-Network Options Screening Report, published on Jemena's website on 18 September 2018, was prepared to establish whether the currently proposed works could be changed in scope or otherwise altered in response to a non-network solution.

### Options Considered

The Non-Network Options Screening Report was predicated on the need for a non-network option to be able to supply N-1 capacity of 45 MVA at FW zone substation (which would allow all of the assets in poor condition to be retired). It was also recognized that a non-network solution supplying 12 MVA may be viable if two switchboards were replaced. Smaller non-network solutions would not provide sufficient capacity to be viable options.

Jemena has also developed network solutions to remediate the assets that are in poor condition and to meet the long term demand for electricity in the area. These options are listed below, and compared to the "Do Nothing" Option 1 (Running assets until they fail):

- Option 2 - Replace two switchboards at FW Zone Substation (use two transformers) and transfer 15 MVA from FW to Tottenham Zone Substation (TH) (requires additional feeder works);
- Option 3 - Replace two switchboards at FW (use two transformers) with no feeder augmentation and availability of one cold spare transformer; and
- Option 4 - Replace three switchboards at FW and operate with three transformers.

### Proposed preferred option

The options analysis identifies that:

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

It should be noted that Option 4 (the Preferred Option) was tested under a range of sensitivities including variations in costs and value of customer reliability. In each case, Option 4 was confirmed to provide positive economic benefits and be the highest ranked option.

It is also noted that Option 4 (the Preferred Option) is expected to generate additional benefits which were not quantified as part of this appraisal, which further supports the case for prompt investment:

- Safety – as is common practice with the electricity sector, Jemena did not undertake a quantified assessment of the safety benefits of each option, which were considered likely to be significant but unlikely to affect the ranking of options.
- Secondary asset failure – the supply risk associated with the replacement of secondary assets such as relays was also not quantified as it was considered second order, and unlikely to affect the ranking of options.

Jemena intends to proceed with the Footscray West replacement plan as soon as possible to address the ongoing safety and reliability risks. Table 1–1 below shows the summary for preferred option.

**Table 1–1: Summary of cost benefit analysis for preferred option**

| | 'Do Nothing' Option 1 ($M, 2020 prices, discounted to 2020) | 'Preferred' Option 4 ($M, 2020 prices, discounted to 2020) |
|---|---|---|
| Network improvements capital cost | - | (15) |
| Cost of Expected Energy at Risk | (18,219) | (2) |
| **Total Project Benefit** | **-** | **18,202** |

### Submission and next steps

Jemena invites written submissions on this report from Registered Participants, interested parties, AEMO and non-network providers.

All submissions and enquiries should be directed to:

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Email: PlanningRequest@jemena.com.au
Phone: (03) 9173 8560

Submissions should be lodged with us on or before 14 February 2020.

All submissions will be published on Jemena's website. If you do not wish to have your submission published, please indicate this clearly.

Following our consideration of any submissions on this Draft Project Assessment Report (DPAR), we will proceed to prepare a Final Project Assessment Report (FPAR). That report will include a summary of, and commentary on, any submissions to this report, and present the final preferred solution to address the Footscray West Zone Substation Switchgear and Relay condition risk. Publishing the FPAR will the final stage in the RIT-D process.

We intend to publish the FPAR by 31 March 2020. Note that if no submissions are received on this report, we will discharge our obligation to publish the FPAR, and instead include the final decision in the 2020 Distribution Annual Planning Report.

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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. |
| Constraint | Refers to a constraint on network power transfers that affects customer service. |
| Continuous rating | The permissible maximum demand to which a conductor or cable may be loaded on a continuous basis. |
| Jemena Electricity Networks (JEN) | One of five licensed electricity distribution networks in Victoria, JEN is 100% owned by Jemena Limited and services close to 330,000 customers via an 6,900 kilometre distribution system 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 Mega (million) Volt-Amperes which is 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. |
| 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 certain limit ($6m), in the National Electricity Market (NEM). |
| Reliability of supply | The measure of the ability of the distribution system to provide supply to customers. |
| System normal | The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices. |
| 10% POE condition (summer) | Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, 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 JEN, 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

| | |
|---|---|
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| BY | Braybrook Zone Substation |
| FE | Footscray East Zone Substation |
| FW | Footscray West Zone Substation |
| JEN | Jemena Electricity Network |
| KTS | Keilor Terminal Station |
| MD | Maximum Demand |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NPV | Net Present Value |
| PD | Partial discharge |
| POE | Probability of Exceedance |
| TH | Tottenham Zone Substation |
| RIT-D | Regulatory Investment Test for Distribution |
| VCR | Value of Customer Reliability |
| YVE | Yarraville Zone Substation |

# 1. INTRODUCTION

This section outlines the purpose of the Regulatory Investment Test for Distribution (RIT-D), Jemena's objective in undertaking its network planning role, and the structure of this draft project assessment report (DPAR).

## 1.1 RIT-D PURPOSE AND PROCESS

Distribution businesses are required to go through the Regulatory Investment Test for Distribution (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 National Electricity Market (the preferred option).

The RIT-D applies in circumstances where a network problem (an "identified need") exists and the estimated augmentation component capital cost of the most expensive potential credible option to address the identified need is more than $6 million. As part of the RIT-D process, distribution businesses must also consider non-network 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 for those projects greater than $11 million in value where a non-network solution may be potentially viable. The currently proposed works at FW could be changed in scope or otherwise altered in response to a non-network solution. Hence Jemena has considered the credibility of potential non-network options as alternatives or supplements for the FW replacement works.

A viable non-network solution would involve implementing measures capable of meeting maximum forecast summer energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). The total requirement from all power sources is in excess of 43 MVA (10% POE maximum forecast varies between 43.4 MVA in 2021 and 38.9 MVA in 2029).

A non-network option supplying 43 MVA, the forecast consumer load supplied from FW zone substation, would allow all of the assets in poor condition to be retired. A non-network solution supplying 12 MVA may be possible if a part of the network is renewed instead. Smaller non-network solutions would not provide sufficient capacity to be viable options. However, overall, the analysis found that a non-network solution could not (either on its own, or in combination with a network solution) provide a viable alternative. The Non-Network Options Screening Report, published on Jemena's website, provides a summary of this analysis.

This document is Jemena's draft project assessment report (DPAR) for the Footscray West Switchgear replacement programme. In accordance with the requirements of the National Electricity Rules, this report describes:

- the identified need in relation to the Footscray West network;
- consideration of potential for non-network options to address the identified needs;
- the credible options assessed that may address the identified need;
- the methodologies used to quantify market benefits;
- the net present value assessment results for the potential credible options assessed; and
- the technical characteristics of the proposed preferred credible option.

## 1.2 OBJECTIVE

Jemena's objective in planning its electricity distribution network is to ensure that reliable distribution services are delivered to its customers at the lowest sustainable cost.

This report is stage two of the RIT-D consultation process. It follows on from our non-network options screening report published on 18 September 2018 and considers network, non-network and hybrid options based on that report and the Australian Energy Regulator's (AER) input to our Electricity Distribution Price Review (EDPR) submission.

# 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 a brief overview of the network limitations. The assessment is based on Jemena's 2019 Load Demand Forecasts Report.

## 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 330,000 homes and businesses for a number of 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.

The Footscray West Zone substation consists of three 66kV/22kV power transformers rated at 30 MVA each, two 66kV circuit breakers and has eight 22kV feeders which supply more than 14,000 Jemena customers.

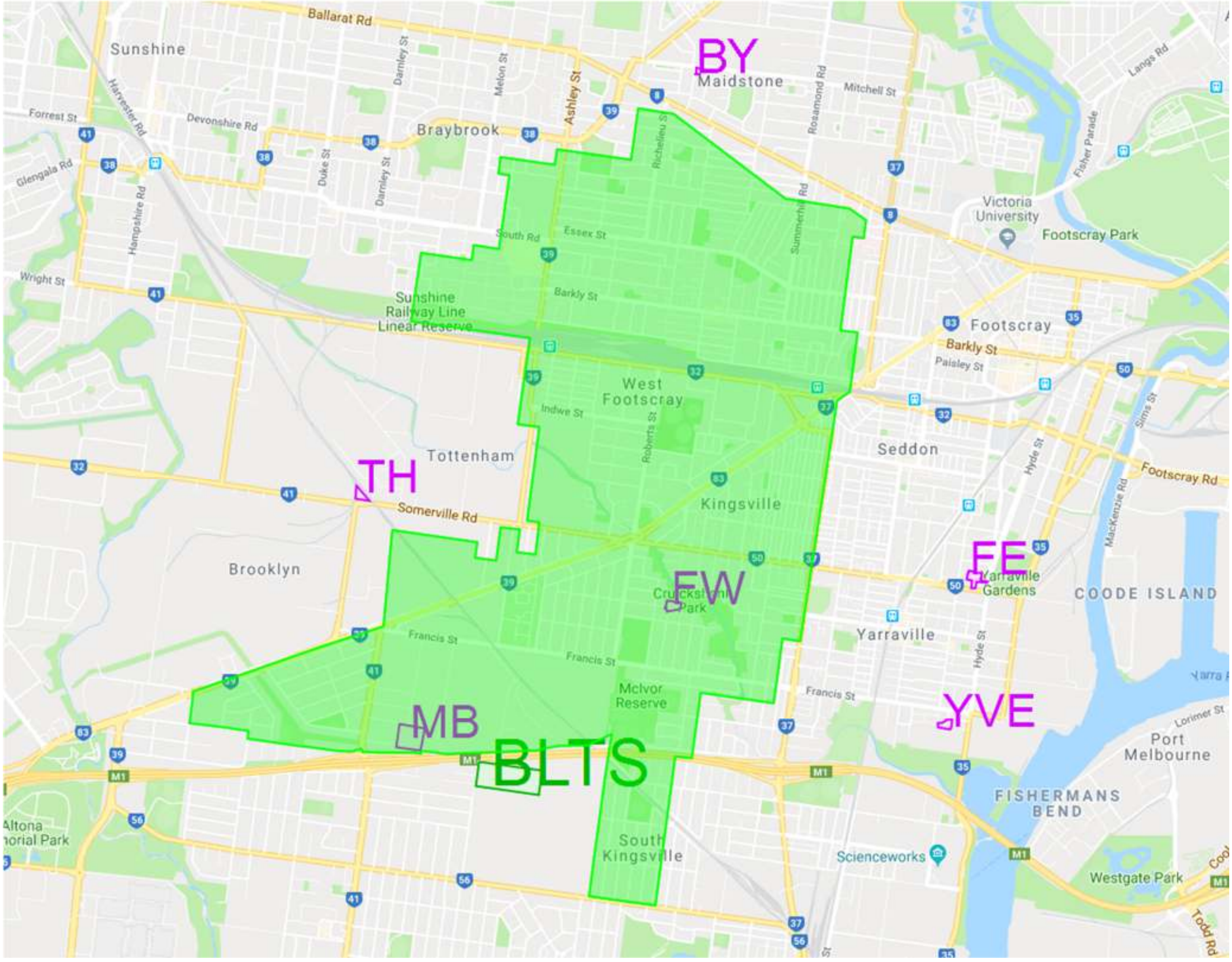
Based on Jemena's 2019 Load Demand Forecasts Report, Footscray West demand is forecast to slightly decline over the period from 2021 to 2029:

- The maximum expected demand is 43.4 MVA for the summer 10% Probability of Exceedance (PoE) in 2021.
- By 2029 it is forecast that demand will be approximately 39 MVA for the Summer 10% PoE which is a slight decrease compared to that in 2021.

## 2.2 GENERAL ARRANGEMENT

Figure 2–1 shows the Footscray West Supply Area as it currently stands including the supply areas of Braybrook (BY), Footscray East (FE), Yarraville (YVE) and Tottenham (TH).

**Figure 2–1: Footscray West Supply Area**



# 3. IDENTIFIED NEED AND PROJECT OBJECTIVES

Jemena has prepared a non-network screening report to assess whether the demand and safety requirements of the Footscray West zone could be achieved either fully, or in part through non-network options. To assess whether the non-network options could be beneficial, it was important firstly to define the identified need for this location.

Jemena has identified the Footscray West zone 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 equipment failure (Safety); and,
- Secondly, the need to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (Reliability).

In line with the purpose of the regulatory investment test for distribution (RIT-D), as outlined in Clause 5.17.1 (b) of the National Electricity Rules, the identified need to address the Footscray West Zone supply limitation is an increase in the sum of customer and producer surplus in the National Electricity Market (NEM); that is an increase in the net economic benefit. This net economic benefit increase is driven by reducing the cost of expected unserved energy (predominantly by a change in the amount of involuntary load shedding in this case) through capacity and reliability augmentation and balancing this benefit against each development option’s cost to identify the optimal augmentation solution and timing.

The primary need in this case is related to reducing the safety risks for Jemena employees, and the public. Jemena’s approach is to categorise the risk it 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 trouble of the risk reduction measures is grossly disproportionate to the benefit gained from the reduced risk.

Consistent with the AFAP principle, Jemena has undertaken this programme with the objective of minimising risks relating to the aging asset in the Footscray West Zone substation. In the short term, Jemena is assessing whether there are any cost-effective risk mitigation controls (i.e. inhibiting the feeder circuit breaker auto reclose functions to reduce potential electrical stresses similar to the risk mitigation measures implemented at Preston Zone substation before it was closed) which can be considered to reduce and minimise the risks highlighted above until the identified need is addressed. Based on experience of the risk mitigation controls applied at Preston Zone substation the costs associated with these actions will be small compared to the cost of expected unserved energy associated with failure of the aged equipment and therefore these costs have not been included in the calculation of net economic benefit.

The risk to Jemena employees and the public, arising from potential major failure is considered to be significant, and hence the benefits of the Footscray West Zone substation upgrade which removes this risk entirely, would also be significant.

Consistent with the AFAP principle, and as is standard practice within the electricity sector, the safety benefits have not been quantified as part of this analysis. Nonetheless, there are real benefits associated with reducing the safety risks inherent in the Do Nothing situation.

These benefits should be considered as additional evidence which confirms the ranking of options.

## 3.1 FIRST IDENTIFIED NEED - SAFETY

The primary identified need for the Footscray West Zone Substation was identified as Safety, based on concern of the risks to workers and the public in the event of an equipment failure of the aging asset. A Do Nothing option would require the aging asset to remain, completely failing to address safety concerns.

The ability to provide a safe network is limited by the poor condition of major equipment at FW Zone substation, which is at risk of failure and poses serious safety and supply reliability risks.

### 3.1.1 CONDITION OF PLANT

This investment is driven by the poor condition of the switchgear and circuit breakers, which are at risk of failure and pose a serious safety risk. The presence of partial discharges mean that the switchgear needs to be replaced as an urgent priority to mitigate significant safety risks to Jemena staff.

In addition, the protection and control relays at this substation have deteriorated. There is a significant risk that faults are not detected and isolated, with failure leading to potential impacts on safety and supply reliability.

The April 2015 switchgear and relays replacement business cases (submitted as part of the 2016-2020 EDPR) provide more detail on the age, condition and risks of the equipment to justify the urgent consideration of options for addressing these issues.

The potential safety risks of a plant failure are listed below:

- Severe injury or death to Jemena's operating personnel and the general public in the vicinity of the substation.
- Risk of step and touch potentials causing injuries to personnel.
- Risk to public of an extended period of supply interruption.

The three indoor 22kV metalclad buses and associated circuit breakers manufactured by Metropolitan Vickers are estimated to be 80 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 replacement of the switchgear is recommended and consistent with regulatory requirements in section 6.5.7 of the National Electricity Rules, and section 3.1 of the Electricity Distribution Code.

### 3.1.2 CREDIBLE SOLUTION REQUIREMENTS

Credible solutions would be required to allow the decommissioning of the existing switchboard and relays to ensure the safety of staff and the public.

## 3.2 SECOND IDENTIFIED NEED - RELIABILITY

Jemena's planning standard for its zone substation assets is based on a probabilistic planning approach which:

- Directly measures customer (economic) outcomes associated with future network limitations;
- Provides a thorough cost-benefit analysis when evaluation network or non-network augmentation options; and;

- Estimates expected unserved energy which is defined in terms of megawatt hours (MWh) per annum, and expresses this economically by applying a value of customer reliability ($/MWh).

Jemena uses this approach to identify, quantify and prioritise investment in the distribution asset. Typically, the expected unserved energy is calculated through understanding the load at risk for each zone substation. This is normally calculated through modelling loads 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). A credible non-network solution should maintain a level of supply reliability which is consistent with Regulatory obligations. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply all load under a N and N-1 network reliability scenario in which the annualised cost of expected unserved energy exceeds the cost of augmentation.

Problems of deterioration of supply reliability due to capacity shortfall, and insufficient transfer capability will result in load shedding during times of peak demand under single contingency conditions.

This will depend on the design and capacity of the current network and the forecast load, presented below in Sections 3.2.1 and 3.2.2.

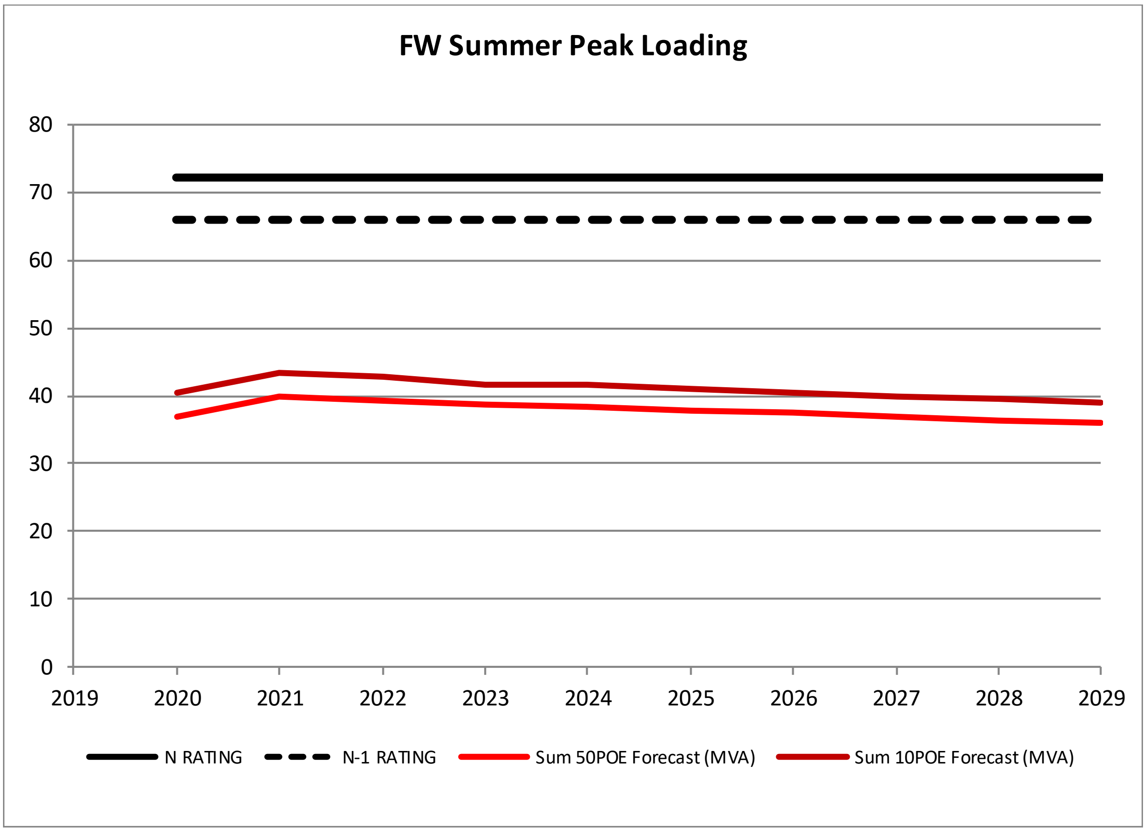
### 3.2.1 LOAD FORECASTS

The demand forecasts for FW are shown below in Figure 3–1. It is noted that demand is forecast to decline slightly over the period from 2021 to 2029. These forecasts include known spot loads where a customer has made an enquiry or application but do not include potential spot loads that may arise in the future:

- The maximum expected demand is 43.4 MVA for the summer 10% Probability of Exceedance (PoE) in 2021
- By 2029 it is forecast that demand will be approximately 36 MVA (in most cases) although slightly higher at 39 MVA for the Summer 10% PoE.

**Figure 3–1: FW summer maximum demand forecast**




### 3.2.2 SUBSTATION CAPACITIES

The station plant items limiting summer and winter capacity are the 66/22 kV transformer thermal limits. Zone Substation FW consists of three 66kV/22kV power transformers, two 66kV circuit breakers and has eight 22kV feeders from three indoor switchboards. The ratings of the key assets are:

- Three transformers rated at 30 MVA each, with a cyclic rating of 33 MVA;
- Each 22kV bus is rated at 1,200 Amps and consist of space for 4 circuit breakers on each switchboard, of which:
  - 8 are currently used for feeder circuit breakers
  - 2 are used for capacitor banks that provide 2 off 7.3 MVAr and 2 off 9.1 MVAr steps for power factor correction.

The total nameplate rating of the station is 90 MVA. The N-1 rating is based on the transformer cyclic rating of 33 MVA. With two of the three transformers in service, the N-1 rating is 66 MVA.

### 3.2.3 CREDIBLE NON-NETWORK SOLUTION REQUIREMENTS

To meet reliability requirements, credible solutions would be required to achieve a N-1 planning scenario. This could be achieved through a range of solutions, including:

- Meeting the identified need in its entirety through a non-network option

- Replacing one switchboard providing 30 MVA of capacity and meeting the remaining capacity through a non-network option
- Replacing two switchboards, each providing 30 MVA of capacity and meeting the remaining capacity through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting summer maximum forecast load with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). The total requirement from all power sources is in excess of 43 MVA (maximum forecast varies between 43.4 MVA in 2021 to 39 MVA in 2029).

# 4. ASSUMPTIONS RELATING TO IDENTIFIED NEED

In accordance with clause 5.17.1(b) of the National Electricity Rules, Jemena's augmentation investment decisions aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market.

To achieve this objective, Jemena applies a probabilistic planning methodology that considers the likelihood and severity of critical network conditions and outages. The methodology compares the forecast cost to consumers of losing energy supply (e.g. when demand exceeds available capacity) against the proposed augmentation cost to mitigate the energy supply risk. The annual cost to consumers is calculated by multiplying the expected unserved energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the value of customer reliability (VCR). This is then compared with the annualised augmentation solution cost.

To ensure the net economic benefit is maximised, an augmentation will only be undertaken if the benefits, which are typically driven by the reduction in the cost of expected unserved energy, outweigh the cost of the proposed augmentation to reduce the unserved energy. Augmentation is not always economically feasible and this planning methodology 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 methodology that we apply is further detailed in our Distribution Annual Planning Report.

The key assumptions that have been applied in quantifying the Footscray West Supply Area limitations are outlined in this section, and include:

- Network asset ratings; and
- Network outage rates.

## 4.1 NETWORK ASSET RATINGS

The Footscray West (FW) Zone Substation consists of three 66kV/22kV power transformers rated at 30 MVA each. There are eight 22kV feeders emanating from three 22kV buses which supply more than 14,000 customers including a number of major HV customers.

All primary plant within FW are protected via protection relays located at the zone substation. These relays provide primary and backup protection to Jemena's assets. Their primary purpose is to detect electrical faults on the network and isolate the fault by tripping Circuit Breakers (CB) associated with the faulted section (also located at FW).

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 major equipment (primarily the switchgear and relays) at FW are assessed to be at a 'high' risk of failure.

Additionally, it should be noted that the secondary assets at FW Zone Substation, 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. Nonetheless, it should be noted that the appraisal of options would be further supported by modelling of this risk.

### Switchgear

Jemena's Condition Based Risk Management (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. CBRM develops a Health Index for each asset based on a scale from 0 to 10. Values of health index in excess of seven represent serious deterioration with a high probability of asset failure.

The CBRM Health Index is a numeric representation of the condition of each asset. Essentially, the health index of an asset is a means of combining information that relates to its age, environment and duty, as well as specific condition and performance information to give a comparable measure of condition for individual assets in terms of proximity to end of life (EOL) and probability of failure. The concept is illustrated schematically below 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 |

The CBRM modelling in 2019 indicated that the FW Zone Substation No.1, 2 and 3 22kV buses have a health index result of 8.4. In Year 3 (2021), the switchgear results are expected to become 8.8. This indicates that the 3 buses have serious issues, including degradation and wear out failures. Combined with the lack of spares this means that the probability of failure is high. These modelling results are consistent with the issues identified.

For the 66kV CBs, the CBRM modelling indicates that the FW 1-2 and 2-3 66kV bus tie CBs both have an existing health index result of 6.6. In Year 3 (2021), the CB result is expected to become 7.1. This indicates that the CBs are in poor condition. This modelling result is also consistent with the issues identified.

For the 22kV transfer buses and associated isolators, the CBRM modelling indicates a 2015 health index result of 6.5 on average. In Year 6 (2020), the health index results were expected to average above 8.0.

For the 22kV CBs, the CBRM modelling indicates that they have current average health index result 7.5. This indicates that the CBs are in poor condition. This modelling result is also consistent with the issues identified.

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 FW zone substation in recent years which are further detailed below. The health index and consequently risk of failure of assets at FW zone substation will continue to increase if no action is taken.

## Relays

FW zone substation is equipped with approximately 79 protection relays out of which 49 are legacy electromechanical relays. These relays were installed in and around the mid-1960s and will be approaching 55 years old in 2021. These relays have a nominal design life of 40 years.

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

- Power Transformers;
- 66kV Bus; and
- 22kV 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

These issues and their associated risks are discussed below.

### *Condition of the Existing Transformer Protection Relays*

No.1, No.2 and No.3 Transformer protection relays are deteriorated electromechanical relays. These relays were installed in mid 1960s and will be approximately 55 years old in 2021. The typical life expectancy of an electromechanical relay is approximately 40 years.

Electromechanical relays are known to mal-operate due to setting drift leading from loss of magnetism. Mal-operation of Transformer High Tension Over-Current (**HTOC**) protection will result in:

- The isolation of power transformer at FW; and
- Isolation of either BLTS-FW No.1 or BLTS-FW No.2 66kV line placing the station under N-1 contingency.

Jemena does not stock any new spare relays as the relay type is a legacy technology. However, Jemena has a small population of retired aged relays that have been collected over the years from protection upgrade projects. These relays are of same vintage and the average age of these retired relays is above 40 years. For this reason Jemena cannot guarantee the performance of the retired relays. These retired relays are only there to be used under emergency situation as an interim solution (e.g. restore supply to customers immediately).

In addition to the condition of the protection relays and lack of spares, the existing Transformer protection scheme is a substandard scheme. Existing X & Y Transformer protection schemes are connected to the same CT cores due to lack of CT cores on the existing CBs. This approach does not provide a complete segregation between the X & Y schemes and is not in accordance with the current Design Standard.

Given that the X & Y transformer protections are deteriorated electromechanical relays sharing the same CT cores, the possibility of a relay failure in the event of a fault is significantly greater. In the event of a relay failure the consequences could include:

- Serious injury to Jemena workers; and/or
- Catastrophic damage to the transformer costing approximate $2M to replace.

### *Condition of the Existing Capacitor Bank Protection Relays*

Existing No.1 and No.3 Capacitor Bank Protection schemes are implemented on SPAJ 140C and SPAJ 160C relays and are scheduled for replacement in 2023. These relays have a history of failures across the network and have been targeted for replacement in the Protection & Control Asset Class Strategy. There are a number of projects proposed over the next five years to replace these relays across the Jemena network (AW, BD, BY, CN, ST etc).

When the Cap Bank primary protection fails to operate for a fault, then the backup protection will be required to clear the fault. In the case of capacitor bank fault, 22kV bus over-current protection scheme will operate as the backup protection, isolating the 22kV bus to clear the fault.

Relying on this backup protection to clear the fault has two sub-optimal consequences:

- Increased customer outages – The number of customers that will lose supply will increase because the backup protection has isolated a wider area of the network. In the case of a capacitor bank fault, the backup protection will result in all the customers supplied by that bus losing supply – rather than isolating the capacitor bank.
- Increased possibility of damage to the Capacitor Bank – It takes longer for backup protection to clear the fault, and as a consequence, capacitor banks will be exposed to overvoltage stress for a longer period. This would cause the capacitor cans to fail requiring replacement.

## 4.2 NETWORK OUTAGE RATES

The network outage rates applied in a probabilistic economic planning assessment can have a large impact on selection of the preferred option and the optimal timing of that option. Jemena has considered the potential failure of switchgear and associated relays, switchboards (i.e. the 22kV bus), and transformers in its assessment of the options.

The failure of battery banks has not been considered, as remedial work on batteries at FW has recently been undertaken and the likelihood of further failures is now considered low.

*Switchgear Failure*

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

- Insulation degradation due to Partial Discharge (PD);
- Thermal condition, burnt contacts;
- CB trip free;
- Leaking oil; and
- Relay failure causing maloperation.

Thermal faults due to high resistance connections are not uncommon for oil filled CBs. Two other similar failures have occurred at zone substation FT (Flemington) and EP (East Preston), but on different branded switchgear.

The CB thermal condition and a trip free 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 a major maintenance intervention to replace gaskets. Given the overall poor condition of the switchgear, however, a major oil leak would likely result in retirement of the switchgear. The probability of a major oil leak is considered low and therefore oil leaks have not been considered further in this assessment.

Relay failure causing maloperation is rare, as most relay failures result in a failure of protection schemes rather than maloperation of the switchgear. Therefore, relay failures have not been considered further in this assessment.

There are 22 CBs installed at FW and FE of similar type and 42 fault records in 10 years. The major issue is the presence of Partial Discharge (PD) caused by loss of insulation at near 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. There is a feedback loop, as once partial discharge has occurred, there is more rapid insulation deterioration, and hence more change of further partial discharges. Consequently, Partial Discharge levels will rise and failure will ultimately occur.

As switchgear ages, the likelihood of a catastrophic failure increases. A catastrophic failure of the 22kV switchgear at FW would include interruption of supply to the entire station, as the switchgear contains bulk oil CBs and has a high likelihood that failure will result in fire and dense smoke affecting adjacent equipment and fire-fighting activities requiring de-energisation of the station.

The probability of failure of the FW switchgear was based on predictions of remaining life taken from our CBRM assessments. Distribution curves were fitted to the data to establish a probability of failure curve. This was then compared to Perk's formulae as a sense check.[1]

When considering the switchgear at FW, it was possible to correlate a good fit and correlation of historical failures with a normal distribution failure curve based on the condition monitoring results and the output of CBRM's health index for FW switchgear.

We note that a Weibull distribution curve most often fits the failure data for distribution equipment. In this case, the failure data did not converge on a Weibull distribution. This is likely due to the small dataset available for analysis. Adding data for similar switchgear at other zone substations (FE) did not provide a better distribution fit and therefore this data was not used in the assessment.

*Bus Failure*

Catastrophic insulation failure can be triggered by lightning and other line surges anytime over the next 5 years. Insulation degradation at normal service voltage can be cyclical due to temperature variations over the same period, ultimately resulting in failure. Based on CBRM and presence of PD, it is possible that one 22kV indoor buses could fail beyond repair due to poor condition in the next 5 years. However, since the most likely trigger for failure is a lightening surge and the bus is well protected against these, the probability of this failure mode could not be adequately quantified and hence a bus failure has not been included in the assessment.

*Transformer failure*

Due to the small data set available for this analysis it was not possible to fit a failure distribution curve.

Hence, for the purposes of this appraisal the probability of a transformer failing was assumed to be 1 in 100 years, with a repair time of 2.6 months. This approach may potentially underestimate the case for investment but demonstrates that even on an optimistic assessment of transformer life cycle, there is a compelling case for investment.

[1] Perk's formula is an exponential distribution optimised for electrical assets (primarily transformers).

# 5. SCREENING FOR NON-NETWORK OPTIONS

## 5.1 TYPES OF NON-NETWORK OPTIONS CONSIDERED

Potential non-network options that could meet the project objectives (as envisaged in the AER (Guidelines Section 7.1)) were considered based on two alternatives, Generation or storage, and Demand Management. Each of these, and the limitations imposed by the current customer profile, are discussed below.

### Generation

Generators in the assessment include the following types:

- Gas turbine power stations – stand-alone generation built for the purpose of replacing the aged network assets;
- Co-generation from industrial processes; and
- Generation using renewable energy – typically using gas collected from land-fill or a wind turbine embedded in the sub transmission or distribution network.

Co-generation solutions owned by a customer could have cost benefits to that customer and hence be more economic than a generator for the sole purpose of network support.

### Storage

Storage could be by a large battery installation or by a large customer energy storage scheme. The assessment did not differentiate the type of storage solution.

### Demand side management

Demand side management, such as voluntary load reduction or small battery storage, can alleviate supply risks caused by network inadequacies by reducing and/or shifting the peak demand. The resulting reduction in peak demand can potentially defer the need for major network augmentation or help to better manage the risk until a major network augmentation can be commissioned or is economically feasible.

In the case of Footscray West, the need is to remove aged assets from service rather than to delay the works and, therefore, demand side management was assessed only as a replacement for the network assets.

### Limitations due to customer profile

Potential embedded generation, energy storage or demand reduction solutions are limited by the demand of a 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.

The *Load forecasts 2019 Final* report provides information on customer composition and their share of maximum peak load in 2019 and estimates there is a total of 14,094 customers consuming 42.4MVA peak summer load in 2019 and comprising:

- 13,275 residential customers consuming 18.062 MVA peak summer load (average 0.0014 MVA)
- 789 commercial customers consuming 8.014 MVA of peak summer load (average 0.0102 MVA)

- 30 industrial customers consuming 16.324 MVA of peak summer load (average of 0.5441 MVA).

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

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

Currently there is no HV connected embedded generation supplied from FW zone substation other than the small residential and commercial solar PV. For FW, there are 1161 solar installations with a capacity of 3.7 MW.

## 5.2 CREDIBLE SCENARIOS

The NER requires proponents to investigate whether a non-network option (or combination of non-network measures) is capable of avoiding the need for investment in a network solution or at least allows a smaller network investment to meet the identified need.

Potential non-network scenarios are:

1. Meeting the identified need in its entirety through a non-network option
2. Replacing one switchboard providing 30 MVA of capacity and meeting the remaining capacity through a non-network option
3. Replacing two switchboards, each providing 30 MVA of capacity and meeting the remaining capacity through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting maximum forecast summer energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). The total requirement from all power sources is in excess of 43 MVA.

### 5.2.1 SCENARIO 1 – MEETING IDENTIFIED NEED THROUGH A NON-NETWORK OPTION

A viable non-network generation option that replaces the capacity currently provided by FW that reliably meets customer requirements in an N-1 situation requires:

- two generators each supplying 43 MVA; or
- three generators each supplying 22 MVA.

This would enable the system to meet maximum demand in an N-1 situation. Adding demand management or efficiency measures to the non-network option would reduce the generation requirements stated above. For example, if management and efficiency reduced peak summer demand to 42 MVA the non-network generation component could be reduced to two generators of 42 MVA or three generators of 21 MVA each.

The costs of the total replacement scenario are likely to exceed those of the preferred network option. For example, the cost of a 23 MVA gas fired generator is approximately $15.9 million plus installation and operating costs (Source: Gas Turbine World 2017). A non-network option is likely, therefore, to cost over $50 million (e.g. providing 3 generators each costing $15.9 million = $48 million plus installation and operating costs). This does not allow for some reduction in peak demand through non-network management and efficiency measures. This would lead to a much higher marginal cost to the customer compared to a network solution of around $10 million for the replacement of all three switchboards 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 – REPLACING ONE SWITCHBOARD AND RETAINING ONE TRANSFORMER

If only one switchboard and related protection relay assets were replaced providing the network capacity equivalent to one transformer (30 MVA), a viable, non-network would be required to supply enough power, and/or enable a sufficient reduction in demand, to supply the peak load should the single transformer fail.

A viable non-network generation option that could meet customer requirements in an N-1 situation requires two generators each supplying 23 MVA (assuming no demand management or greater efficiency). This is likely to cost at least $32 million (gas generation of 46 MVA excluding installation and operating costs) (Source: Gas Turbine World 2017).

#### 5.2.3 SCENARIO 3 – INSTALLING TWO SWITCHBOARDS, EACH OF 30 MVA CAPACITY (WITH AND WITHOUT TRANSFERS)

The most realistic scenarios 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, we considered the potential credibility of non-network options for covering the gap when only two switchboards are replaced at FW so it has a new configuration of two switchboards and two transformers with a capacity of 60 MVA and N-1 capacity of 33 MVA. 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 which would leave a shortfall of maximum required load in 2018 of 12.4 MVA (45.4 MVA – 33 MVA which is the cyclic rating of the remaining transformer). By 2019 this shortfall is expected to be 12.0 MVA and by 2020, 11.6 MVA.

The cost of providing this scale of generation is likely to be in the order of $10 million plus installation and operation costs (Source: Gas Turbine World 2017).

The required output of a non-network solution might be further reduced if the renewal of two switchboards was coupled with some load transfer to surrounding substations. In this situation, non-network options might need to deliver half the required load (e.g. 6 MVA) with load transfers covering the remainder. The non-network generation cost is likely to be in the order of $7 million for gas generation and $5.5 million for diesel generation plus installation and operating costs (Source: Gas Turbine World 2017).

### 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 of non-network options were:

1. **Addresses the identified need:** by delivering energy to reduce or eliminate the need for the investment
2. **Technically feasible:** there are no constraints or barriers that mean an option cannot be delivered in the context of this investment
3. **Commercially feasible:** non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment
4. **Timely** and can be delivered in a timescale that is consistent with the identified need.

Figure 5–1 shows the rating scale we have applied for assessing non-network options.

**Figure 5–1: Assessment Rating Criteria**

| Rating | Colour Coding |
|---|---|
| Does not meet the criterion | |
| Does not fully meet the criterion (or uncertain) | |
| Clearly meets the criterion | |

The NNOSR considered whether a non-network option (or combination of non-network measures) could provide 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 could 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).

Figure 5–2 shows the assessment of non-network options against the RIT-D criteria. It should be noted that when considering the non-network options, the cost of connection into the network was not considered (e.g. connection of generators). This decision reflected the fact that the non-network options were already ruled out by other factors, and the cost of connection would further strengthen the case to reject the non-network options.

Overall, the assessment shows that a credible non-network option was not identified (whether considered in isolation, or in combination with network solutions).

**Figure 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 Customer energy efficiency | | | | |
| 2.4 Demand response (curtailment of load) | | | | |

## 5.4 NON-NETWORK ASSESSMENT COMMENTARY

### 5.4.1 GENERATION AND STORAGE

The assessment commentary for each of the generation and storage options is:

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

*Identified need* – Reduces safety risks of running old plant beyond life. Capable of meeting identified need through provision of multiple gas generators (Met).

*Technical* – Significant constraints and barriers to deployment of equipment to generate between 6 MVA and 45 MVA 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. For example, the minimum scenario of installing a 6 MVA gas fired generator at a cost of approximately $5.6 million plus installation compares to a saving of just over $1 million from not installing a third bus at FW and requires additional network expenditure of $0.2 million in transferring 6 MVA of load to adjacent substations, assuming minimal feeder works (not met). 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 at market prices. 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 and any required 22kV connections to FW) mean this is unlikely to be completed by 2021 (not met).

Overall – not a potentially credible option.

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

*Identified need* – Reduces safety risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. There is no information on current solar generation by customers but estimate that the generation of 6 MW (the minimum required for a viable non-network option) using solar is likely to require 15 acres of land (https://www.quora.com/How-much-land-is-required-to-setup-a-1MW-solar-power-generation-Unit-1). Devoting this amount of land to energy production in a dense, urban environment is not feasible. As noted in Section 5.1 solar installations in FW provide a relatively small capacity of 1.51 MW. In addition, the generation profile of solar power may not align to the consumption profile of consumers (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 facility to generate 6 MW in this locality. These include zoning, planning and environmental constraints given the land requirements and the lack of evidence of the availability of approximately 15 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. The solarshare 1 MW solar project in Canberra (https://solarshare.com.au/solar-farm-project/greenfield-project/) is costing $3 million and in the Footscray environment purchasing up to 15 acres of land is likely to be significant. This is unlikely to be cost effective when compared to 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 2021 (not met).

Overall – not a potentially credible option.

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

*Identified need* – Reduces safety risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. Based on a 2 MW wind turbine requiring 1.5 acres of land (https://sciencing.com/much-land-needed-wind-turbines-12304634.html), a 6 MW wind turbine would require 4.5 acres. Devoting this amount of land to energy production 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, 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 unlikely to be allowed. (not met).

*Commercial* – As for commercial solar generation the cost of acquiring land and installing wind turbines is likely to significantly exceed the costs of the preferred network solution and means this form of generation is unlikely to be viable. Large scale windfarms are delivering capacity at $2.25 million per MW (https://reneweconomy.com.au/agls-new-200mw-silverton-wind-farm-to-cost-just-65mwh-94146/) and this small scale installation is likely to be more expensive in an urban environment (not met).

*Timing* – The requirement to coordinate the installation of generation across a relatively large number of industrial power consumers together with likely planning requirements mean it is uncertain that a 2021 completion date could be achieved (not fully met).

*Overall* – not a potentially credible option.

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

*Identified need* – Reduces safety risks of running old plant beyond life. There are 30 industrial customers consuming 16.324 MVA at the summer peak (average 0.5441 MVA) and 789 commercial customers consuming 8.104 peak MVA (average 0.0102 MVA). As noted in Section 3.2.1 there are only two larger industrial (HV) customers with maximum demands of 1.7 MVA and 1.4 MVA. 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.

Note: Jemena's 2018 Distribution Annual Planning Report (Section 5.10.4) on customer proposals reports that:

*In 2018, Jemena has not received any connection enquiries for embedded generators that have a generation capacity greater than 5 MW. Jemena believes this to be a reflection of:*

- *The nature of the JEN network, which services the north east of greater metropolitan Melbourne, where there is limited availability of physical space for a significantly sized embedded generator.*
- *Underlying weaker energy and maximum demand growth in the Victoria region.*
- *A preference for smaller scale embedded generation, particularly roof top solar, for which the JEN network has seen an ongoing increase in installed capacity.*

*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 (4 MVA) to be about $3.9 million and 6.5 MVA about $5.6 million both excluding installation and operating costs. This is unlikely to be commercially viable given the much lower costs of providing this capacity using a network solution.

*Timing* – Planning processes, the nature of the investment and likely obstacles, together with design requirements (both for turbines and any required 22kV connections to FW) mean this is unlikely to be completed by 2021 (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 in relation to the marginal costs for a full network solution.

Overall – not a potentially credible option.

### 5.4.2 DEMAND MANAGEMENT/EFFICIENCY

The assessment commentary for the demand management/efficiency options is:

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

*Identified need* – Reduces safety risks of running old plant beyond life. This option is unlikely to meet the identified need because of the absence of very large industrial power users where this type of action could result in significant power savings (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 2020 (fully met).

Overall – not a potentially credible option.

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

*Identified need* – Reduces safety risks of running old plant beyond life. Solar household penetration in Australia is on average 16%. Satellite imagery suggests that the proportion for the FW catchment is unlikely to exceed this average figure. Approximately 850 of the 1,362 residential customers (62%) would need to have a 2kw solar system installed to provide 6 MW capacity (based on generation of 7.2 kWh per day - https://www.solarchoice.net.au/blog/how-much-energy-will-my-solar-cells-produce/). Currently, solar installations in FW provide a relatively small capacity of 3.7MW. This rate of take up is not considered to be achievable (not met).

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

*Commercial* – Achieving a greater than average solar take up would require a financial incentive and to achieve the level of take up for this option to be potentially credible would require a very high subsidy (not fully met).

*Timing* – This option could be completed by 2021 but there is uncertainty given the large number of customers that would need to install solar (not fully met).

Overall – not a potentially credible option.

- **Customer energy efficiency (2.3)**

Identified need – The assessment for this option is similar to the results for Option 2.2. Each of Jemena's approximately 14,000 customers would have to reduce consumption by approximately 13% for the summer peak to achieve a 6 MVA reduction (6 MVA/45.4 MVA = 13.2%). This scale of reduction is considered unrealistic even if accompanied by subsidies to consider doing this (not met).

*Technical* – This option is technically feasible and the type of efficiencies required achievable if sufficient customers are willing to invest in such measures (fully met).

*Commercial* – Unclear that this is commercially feasible. (not fully met).

*Timing* – This type of mass action would be difficult to promote and implement by 2021 (not fully met).

Overall – not a potentially credible option.

- **Demand response (curtailment of load) (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 outlines the proposed works associated with each credible option. The base case is established, to compare the options identified. The preferred option is presented.

## 6.1 "DO NOTHING" OPTION (BASE CASE)

The assessment of credible options is based on a cost-benefit analysis that considers the future expected unserved energy of each credible option compared with the base case, where no augmentation option is implemented.

In assessing the credible options to alleviate the impact of constraints on its network, Jemena applies VCR values based on the Australian Energy Market Operator's (AEMO) 2014 Value of Customer Reliability Review. AEMO's most recent VCR estimate has been escalated to 2020 dollars assuming a CPI increase of 1.7%. Applying the sectorial values developed by AEMO to Jemena's latest load composition of approximately 47% commercial, 32% residential and 21% industrial customers, Jemena's composite VCR figure for 2020 is $42,034/MWh.

The 'Base Case' option gives the basis for comparing the cost-benefit assessment of each credible augmentation option, starting the analysis from 2020 when proposed expenditures will be incurred. The base case is presented as a do nothing option, where we would continue managing network asset loading through involuntary load shedding but not initiate any augmentation project.

## 6.2 NETWORK OPTIONS

In 2019, Jemena undertook an analysis of the following options for completing the Switchgear and secondary equipment replacement task.

- Option 1 - Do Nothing: running assets till they fail;
- Option 2 - Replace two switchboards at FW (use two transformers) and transfer 15 MVA from FW to TH (requires additional feeder works) and availability of one cold transformer;
- Option 3 - Replace two switchboards at FW (use two transformers) with no feeder augmentation and availability of one cold transformer; or
- Option 4 - Replace three switchboards at FW and operate with three transformers.

### 6.2.1 PREFERRED OPTION

This review confirmed Option 4 – Replace three switchboards at FW and operate with three transformers as the preferred network option. The other options could potentially allow a non-network proponent to offer a partial solution (this possibility is explored further in Section 5).

Option 4 includes replacement of the following equipment in 2020.

- 66kV buses, isolators, circuit breakers, disconnector switches, surge diverters and transformer bushings.
- Three 22kV switchboards, 22kV station service transformers, isolators and feeder cables.

- No.3 transformer roof enclosure.
- Secondary protection and control relays.
- SCADA and Communications equipment.
- DC supply system.

# 7. 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.

## 7.1 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 (2020-2029) were based on Jemena's 2019 load demand forecasts. Following on, zero demand growth was assumed 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; and
- Timing of the expenditure.

### 7.1.1 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), which has been based on AEMO's Value of Customer Reliability review in 2014, but updated to 2020 values yielding a value of $42,034 MWh (refer Section 6.1).
- Jemena forecasts and models hourly load for the forward planning period and quantifies the expected unserved energy (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. The costs have been included in the net economic benefit assessments summarised in Section 8.

### 7.1.2 TIMING OF EXPENDITURE

The costs of credible options assessed in this RIT-D include the works required to complete the Footscray West Switchgear and relay replacement works (Option 4). All costs will be incurred by end 2021.

By including the cost of the major works expected under each credible option, Jemena has captured potential changes in expenditure timing between the various credible options. These market costs, and any associated benefits, are captured in the NPV analysis, and applied to the credible option rankings, outlined in Section 8.

### 7.1.3 CHANGES IN LOAD TRANSFER CAPACITY

In the 'Do Nothing' scenario, FW provides significant load transfer capacity to support the surrounding ZSS, specifically 10 MVA to Braybrook (BY), 3 MVA to Footscray East (FE) and 11 MVA to Tottenham (TH). Note, Yarraville (YVE) also provides load transfer capacity for these ZSS.

Option 2 and Option 3 both result in reduced effective load transfer capacity from FW. For Option 2 the effective load transfer capacity for BY has reduced by 7 MVA, for FE by 1 MVA and for TH by 8 MVA.

For Option 3 the effective load transfer capacity for BY has reduced by 10 MVA, for FE by 3 MVA and for TH by 11 MVA.

Option 4 (replace 3 switchboards) is the only option to maintain current load transfer capacity in the area.

Under N-1 at FW, BY, FE or TH, all load can be resupplied under all options.

Under N-2 at FW, BY, FE or TH (loss of station) not all load can be resupplied from adjacent substations. The Energy at risk is small but has been included in the analysis.

## 7.2 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:

- Voluntary load curtailment;
- Costs to other parties;
- Option value; and
- Electrical energy losses.

### 7.2.1 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 Footscray West 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 with respect to differentiating between network options.

### 7.2.2 COST TO OTHER PRATIES

The Footscray West Zone primary need relates to safety concerns, and the secondary need to reliability constraints. Neither of these concerns are linked to other parties.

As there are currently no applications from other parties (expected, or underway) which would be expected to affect the option specification, the market benefits associated with costs would not change the rankings of the options, and therefore, have not been quantified.

### 7.2.3 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 project, 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 decommissioning of the aging asset 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.

### 7.2.4 ELECTRICAL ENERGY LOSSES

Reducing network utilisation, through network impedance or load changes in the Footscray West area could result in a change in network losses. The network options are, however, all expected to reduce network losses 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.

## 7.3 VALUING MARKET BENEFITS

Clause 5.17.1 of the NER requires that the RIT-D assessment is based on a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand. Since this RIT-D is driven by a safety need, demand growth is not the major consideration. Nonetheless, the secondary need, reliability has been quantified based on reference to demand growth forecasts. The Jemena demand forecasts for the Footscray West Zone presume very low growth over the appraisal period. Future supply developments are not expected to significantly impact the assessment results, preferred option or optimal timing.

The Guidelines note that “*Where a change to a parameter or value in a central reasonable scenario yields or is likely to yield a change to the ranking of credible options by net economic benefit, the RIT-D proponent should adopt additional reasonable scenarios that reflect variations in that parameter or value*”.

For this RIT-D, Jemena has assumed low demand growth as a base case. Testing higher demand growth scenarios would not be likely to change the ranking of credible options by net economic benefit, and therefore, alternative demand scenarios have not been tested.

### 7.3.1 SENSITIVITY ANALYSIS

Jemena critically assessed the parameters used in the base case and believes that the key variables applied in valuing the economic benefits are outlined in this section, and include:

- Value of customer reliability (VCR); and,
- Project costs.

Note, a discount rate of 6.20% has been applied in assessing the Net Present Value (NPV) assessment of credible options. This discount rate is based on the AER's approved weighted average cost of capital (WACC) for Jemena's electricity network in 2019. The ranking of credible options is not sensitive to changes in the discount rate (as the majority of costs are incurred in the early years of analysis).

#### 7.3.1.1 Value of customer reliability

The cost of unserved energy is calculated using the value of customer reliability (VCR). This is an estimate of how much value electricity consumers place on a reliable electricity supply.

Based on the Australian Energy Market Operator's (AEMO) 2014 Value of Customer Reliability Review, Jemena's composite VCR figure for 2020 is $42,034/MWh.

Sensitivities to the base VCR of ±20% have been considered, resulting in a low VCR sensitivity of $33,627/MWh and a high VCR of $50,441/MWh.

#### 7.3.1.2 Project costs

The 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 estimate range of ±30%, which has therefore been applied to the sensitivity studies for this RIT-D. Costs include disposal of old plant, and scrap value where appropriate.

Project costs are presented in 2020 prices. A consumer price index (CPI) rate of 1.7% per annum has been applied to the 2019 project works estimates to bring them into 2020 prices.

#### 7.3.1.3 Asset failure rate assumptions

The failure rates assumed in the analysis are set out in Section 4.2. No sensitivity analysis has been undertaken for failure rates as:

- Options 2, 3 and 4 all allow for the aged switchgear to be decommissioned and therefore the impact of uncertainty in the failure rates adopted for the aged switchgear affects only the Do Nothing option. Hence there is no change across the other options when compared to the Do Nothing option.
- The new switchgear has a low probability of failure that is uniform across Options 2, 3 and 4.

# 8. OPTIONS ANALYSIS

This section presents the base case limitation and summarises the augmentation analysis results of potential options. The annualised limitation cost for the Base Case (Do Nothing) and each of the four network augmentation options is presented for the next nine year period, as is the net economic benefit calculated for each potential option. The net economic benefit analysis has been assessed considering the network risk and expected augmentation costs for the twenty year period from 2020 to 2039.

Each potential augmentation option has been ranked according to its net economic benefit, being the difference between the market benefit and the costs within the assessment period.

## 8.1 NETWORK LIMITATIONS

### 8.1.1 OPTION ONE – DO NOTHING

This option considers the impact of a 'Do Nothing' scenario, which would include no additional investment in the Footscray West Zone substation (beyond any previously committed investment). Involuntary load shedding would be expected under network outage conditions. The impact of the network limitations under the base case is presented in Table 8–1 below.

**Table 8–1: Do Nothing - Cost of Expected Energy at Risk ($M, 2020 prices, discounted to 2020)**

| Item | Option 1 – Do Nothing |
|---|---|
| Cost of expected energy at risk | (18,219) |

### 8.1.2 OPTION TWO – REPLACE TWO SWITCHBOARDS AND TRANSFER 15 MVA FROM FW TO TH

Option two establishes the station with two new switchboards and hence only two of the existing three transformers. The remaining transformer will be available as a cold spare. The option considers that the rating of two transformers (36 MVA) is almost sufficient to carry the required load (approximately 40 MVA). Transferring 15 MVA of load from FW to substation TH removes the overload at FW and provides a load transfer capability to improve operational flexibility.

The option includes the cost of the switchboard replacement and the feeder modification to enable the permanent transfer of 15 MVA.

### 8.1.3 OPTION THREE – REPLACE TWO SWITCHBOARDS WITH NO LOAD TRANSFER

Option three establishes the station with two new switchboards and hence only two of the existing three transformers. It considers that the potential overload that might occur at FW (without transferring load away) will only occur for a short period of time (about 190 hours per year) and is limited in magnitude (about 7 MW). While this arrangement does not meet Jemena's planning standards for N-1 for its zone substations, it may be achieved through re-rating the transformers and hence is included as a viable option, noting that the ability to re-rate the transformers has not yet been proven and hence is uncertain.

### 8.1.4 OPTION FOUR – REPLACE THREE SWITCHBOARDS

This option re-establishes the station to its current arrangement with three new switchboards and the current three transformers.

## 8.2 ECONOMIC BENEFITS

FW is a three transformer zone substation with aged switchgear that must be retired.

Option 1 is Do Nothing. A switchgear failure would either affect the connected distribution feeder and, indirectly, the switchboard that the switchgear is connected to, hence affecting several more feeders, or, fail catastrophically and break oil containment causing fire and loss of the station.

For simplicity, the failure of the bus-tie switchgear has not been modelled. This is because the impact of a failure is uncertain. In addition, the failure of the bus-tie switchgear would only affect the Do-Nothing option and have the same impact across all the other options.

Option 2 is to replace 2 switchboards reducing the number of transformers at FW substation to two active transformers and one cold spare. In this scenario, 15 MVA is transferred to TH which requires feeder upgrades. This approach would maintain N-1 capability at FW.

The station load at TH is greatest in 2020 at 29.0 MVA (summer). Adding 15 MVA (as proposed under Option 2) would bring the station loading to 44 MVA. This load would be within the N-1 rating of 47.6 MVA. In this case, 3.3 MVA of load transfer capability would be retained at TH, improving operational flexibility over Option 3, where the load transfer capacity ex TH is zero.

Option 3 is to replace 2 switchboards reducing the number of transformers at FW substation to two active transformers and one cold spare. No load is transferred, resulting in load at risk under N-1. The Station capacity is 33 MVA (with a short term rating of 36 MVA), whereas the estimated station loading is 39.9 MVA (in 2021) dropping to 36.0 MVA (2029 and beyond).

Therefore Option 3 does not meet the N-1 planning criteria established for zone substation assets. However, the EAR is small and is estimated would only occur for a few hours per year.

Option 4 involves replacement of 3 switchboards and re-establishment of current zone substation arrangements. Option 4 provides greater operational flexibility, and resilience of service. The economic analysis shown in Table 8.2 below demonstrates that Option 4 also provides the highest net economic benefits.

**Table 8.2: Cost/benefit analysis ($M, 2020)**

| Item | NPV Capex | NPV of net economic benefit | Project ranking |
|---|---|---|---|
| Option 1 - Do Nothing | - | - | 4 |
| Option 2 - Replace two switchboards and 15 MVA load transfer | (13.9) | 18,199.7 | 2 |
| Option 3 - Replace two switchboards | (13.5) | 18,193.5 | 3 |
| Option 4 - Replace three switchboards | (15.3) | 18,201.7 | 1 |

### 8.2.1 SENSITIVITY ANALYSIS

The key variables applied in valuing the economic benefits were considered to be:

- Value of customer reliability (VCR); and

- Project costs.

The sensitivity of the appraisal to changes in these variables was assessed for two scenarios:

1. Higher than expected costs and lower than expected VCR; and
2. Lower than expected costs and higher than expected VCR.

This analysis demonstrated that the conclusions were not sensitive to the changes, as the ranking of the options remained constant as shown in Table 8–3 and Table 8–4 below..

**Table 8–3: Net Economic Benefits of each Option – High Cost/Low VCR sensitivity test ($M, 2020 prices)**

| Option | NPV Capex | NPV of net economic benefit | Project Ranking |
|---|---|---|---|
| Option 1 - Do Nothing | - | - | 4 |
| Option 2 - Replace two switchboards and 15 MVA load transfer | (16.6) | 14,554.3 | 2 |
| Option 3 - Replace two switchboards | (16.2) | 14,549.4 | 3 |
| Option 4 - Replace three switchboards | (18.4) | 14,555.3 | 1 |

**Table 8–4: Net Economic Benefits of each Option – Low Cost/High VCR sensitivity test ($M, 2020 prices)**

| Option | NPV Capex | NPV of net economic benefit | Project Ranking |
|---|---|---|---|
| Option 1 - Do Nothing | - | - | 4 |
| Option 2 - Replace two switchboards and 15 MVA load transfer | (11.1) | 21,845.4 | 2 |
| Option 3 - Replace two switchboards | (10.8) | 21,837.9 | 3 |
| Option 4 - Replace three switchboards | (12.3) | 21,848.5 | 1 |

## 8.3 PREFERRED OPTION OPTIMAL TIMING

The primary need for this investment is to reduce the safety risks caused by the deteriorated and aging asset. Any delay in design or implementation of this investment would increase the safety risks, and therefore, alternative timings for investment have not been considered.

# 9. CONCLUSION AND NEXT STEPS

The assessment outlined within this report shows that the primary limitations associated with the FW supply are the concerns around the safety of the aging asset at FW and the level of reliability provided by the aging asset.

## 9.1 PREFERRED SOLUTION

The preferred solution is to replace the three aged switchboards and associated protection relays at zone substation Footscray West with three new switchboards and relays at a cost of $15.3 million.

## 9.2 NEXT STEPS

Jemena invites written submissions on this report from Registered Participants, interested parties, AEMO and non-network providers.

All submissions and enquiries should be directed to:

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Submissions should be lodged with us on or before 14 February 2020.

All submissions will be published on Jemena's website. If you do not wish to have your submission published, please indicate this clearly.

Following our consideration of any submissions on this Draft Project Assessment Report (DPAR), we will proceed to prepare a Final Project Assessment Report (FPAR). That report will include a summary of, and commentary on, any submissions to this report, and present the final preferred solution to address the Footscray West Zone Substation Switchgear and Relay condition risk. Publishing the FPAR will the final stage in the RIT-D process.

We intend to publish the FPAR by 31 March 2020. Note that if no submissions are received on this report, we will discharge our obligation to publish the FPAR, and instead include the final decision in the 2020 Distribution Annual Planning Report.