Jemena Electricity Networks (Vic) Ltd

Fairfield Zone Substation (FF) Transformer No.3 Condition and 4th Bus

RIT-D Stage 2: Draft Project Assessment Report

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Fairfield Zone Substation (FF) Transformer No.3 Condition and 4th Bus

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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 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 current and emerging network limitations. 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**) forms Stage 2 of the Regulatory Investment Test for Distribution (**RIT-D**) consultation process. It quantifies the reliability of supply risks associated with the deteriorating condition of network assets within the Fairfield Zone Substation (**FF**), inhibiting the expansion of the substation to support customer growth in the supply area. This DPAR analyses a range of credible options[1] for economically mitigating those risks, including identifying the preferred option.

Identified need

FF is owned and operated by Jemena, providing power to approximately 6,756 Jemena customers and 3,664 CitiPower customers in Melbourne's inner north east, in the suburbs of Fairfield and Alphington within the JEN supply area, and parts of the suburb of Thornbury within the CitiPower supply area.

The condition of the 22/6.6 kV No.3 transformer at FF is deteriorating and is located in a position of the switchyard that inhibits further expansion of the zone substation. Jemena has assessed that this transformer has reached the end of its engineering life, and there is now an unacceptable risk of leaving this transformer remaining in-situ, with increasing consequences for the reliability of electricity supply to Jemena's customers within the supply area.

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

1. to protect power sector workers and members of the public from harm caused by unplanned equipment failure or excessive noise due to deteriorating asset condition (Health and Safety); and,

2. 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 businesses 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[2].

As required by the RIT-D process, 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: Options Screening Report Notice of Determination*, published on Jemena's website on 25 August 2023, 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.

[1] Also reflecting on the potential for hybrid network/non-network credible options, as assessed within the *RIT-D Stage 1: Options Screening Report Notice of Determination*, published on Jemena's website.

[2] Source: AER 2021 RIT and APR cost thresholds review (November 2021).

Options considered

The *Options Screening Report Notice of Determination* was predicated on the need for a non-network or SAPS option to be able to supply a capacity of up to 14 MW at the FF zone substation, which is the capacity needed to meet the shortfalls in FF's forecast maximum demand under single contingency conditions while maintaining current service levels. This capacity would also allow the poor condition No.3 transformer at FF to be retired and removed from the site. It was recognised in that report that a non-network solution supplying 6 MW in 2026 may be viable if it is accompanied by 1 MW increases in capacity each year thereafter, to continue to defer a network solution.

Jemena has also developed a range of network options that attempt to address the identified need and continue to meet the electricity demand requirements of customers in the supply area. These options are listed below, and compared with the base case "Do Nothing" Option 1:

- Option 1 – Base case "Do Nothing", i.e., run assets to failure;
- Option 2 – Replace No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF;
- Option 3 – Retire No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF; and
- Option 4 – Replace No.3 22/6.6 kV transformer, using existing 6.6 kV buses to piggyback cables.

Proposed preferred option

The options analysis and economic evaluation undertaken and documented in this DPAR conclude that:

- Option 2 is the preferred network option; and,
- There are no credible non-network or SAPS options, or combinations of non-network options with network options, which could defer the need for the preferred network option.

Option 2 was tested under a range of sensitivities and scenarios including variations in costs and value of customer reliability. In each case, Option 2 was confirmed to provide positive economic benefits and is the highest-ranked option. Option 2 satisfies the requirements of the RIT-D and is the preferred option.

The preferred option involves replacing the existing FF No.3 22/6.6 kV transformer with a new 22/6.6 kV 18 MVA transformer located in a different area of the switchyard and installing a fourth 6.6 kV bus with new 6.6 kV feeder bays in the location of the existing transformer at a capital cost of $22.3 million (real $2023).

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, 2023)

Present Value of Costs	'Do Nothing' Option 1	'Preferred' Option 2
Network capital investment	(0.0)	(22.3)
Additional opex investment (O&M)	(0.0)	(2.4)
Expected unserved energy (EUE)	(115.5)	(0.0)
Net Present Value of Benefits	**-**	**93.6**

Jemena intends to proceed with the preferred network option and complete it in 2026 to address the increasing reliability of supply risks at FF associated with the deteriorating condition of network assets, inhibiting the expansion of the substation to support customer growth in the supply area.

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 7960

Submissions should be lodged with Jemena on or before 6 October 2023. All submissions will be published on Jemena's website. Please indicate if you do not wish to have your submission published.

Following consideration of any submissions on this DPAR, Jemena will proceed to prepare a Final Project Assessment Report (**FPAR**). That report will include a summary of, and commentary on, any submissions to this DPAR, and present the final preferred option to address the identified need. Publishing the FPAR will be the final stage of the RIT-D process.

Jemena intends to publish the FPAR by 20 October 2023. If no submissions are received on this report, Jemena will discharge its obligation to publish the FPAR by including the final report in its 2023 Distribution Annual Planning Report (**DAPR**).

Table of contents

Executive summary ... iii
Glossary ... viii
Abbreviations ... x
1. Introduction ... 1
1.1 RIT-D purpose and process ... 1
1.2 Structure of this report ... 2
2. Background ... 3
2.1 Supply area ... 3
2.2 Fairfield (FF) zone substation ... 4
3. Identified need ... 5
3.1 Health and safety ... 5
3.2 Reliability of supply ... 5
4. Assumptions relating to the identified need ... 7
4.1 Asset condition ... 7
4.2 Asset capacity ... 9
4.2.1 Maximum demand forecasts ... 9
4.2.2 Substation capacities ... 10
4.2.3 Transfer capacity ... 11
4.3 Quantification of the identified need ... 11
5. Screening for non-network options ... 12
5.1 Types of non-network options considered ... 12
5.2 Credible non-network scenarios ... 12
5.2.1 Scenario 1 – Non-network or SAPS option to meet identified need in its entirety ... 12
5.2.2 Scenario 2 – Non-network or SAPS option to meet identified need in part ... 13
5.3 Assessment approach and Findings ... 14
5.4 Non-Network assessment commentary ... 15
5.4.1 Generation and storage ... 15
5.4.2 Demand management ... 17
5.4.3 Findings in the Notice of Determination ... 18
6. Network options considered in the RIT-D ... 20
6.1 “Do nothing” option (base case) ... 20
6.2 Network options ... 20
7. Market benefit assessment methodology ... 21
7.1 Market benefit classes quantified for this RIT-D ... 21
7.1.1 Involuntary load shedding and customer interruptions ... 21
7.2 Market benefit classes not relevant to this RIT-D ... 21
7.2.1 Changes in load transfer capacity and embedded generators ... 22
7.2.2 Timing of expenditure ... 22
7.2.3 Voluntary load curtailment ... 22
7.2.4 Cost to other parties ... 22
7.2.5 Option value ... 22
7.2.6 Electrical energy losses ... 23
7.3 Sensitivities ... 23
7.3.1 Maximum demand growth rate ... 23
7.3.2 Value of customer reliability ... 23
7.3.3 Capital costs ... 24
7.3.4 Discount rate ... 24
7.3.5 Asset failure rate assumptions ... 24
7.3.6 Summary of sensitivity assumptions ... 24
7.4 State of the world scenarios ... 25
8. Options analysis ... 26

8.1 Option 1 – Do nothing (base case) ... 26
8.2 Option 2 – Replace No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF ... 26
8.3 Option 3 – Retire No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF ... 27
8.4 Option 4 – Replace No.3 22/6.6 kV transformer, using existing 6.6 kV buses to piggyback cables ... 27
8.5 Net economic benefits ... 27
8.6 Sensitivity analysis ... 28
8.7 Preferred option optimal timing ... 29
9. Conclusion and next steps ... 30
9.1 Preferred option ... 30
9.2 Next steps ... 30
10. Appendix A – Checklist of compliance clauses ... 31

List of tables

Table 1–1: Summary of cost benefit analysis for preferred option ($M, 2023) ... v
Table 4–1: Value of EUE ($M, 2022) (central scenario) ... 11
Table 5–1: Assessment criteria rating ... 14
Table 5–2: Assessment of non-network options against RIT-D criteria ... 15
Table 7–1: Base case VCR for FF ... 23
Table 7–2: Sensitivity assumptions ... 24
Table 7–3: Scenarios ... 25
Table 8–1: Do nothing – present value of EUE ($M, 2023) ... 26
Table 8–2: Option 2 – present value of residual EUE ($M, 2023) ... 26
Table 8–3: Option 3 – present value of residual EUE ($M, 2023) ... 27
Table 8–4: Option 4 – present value of residual EUE ($M, 2023) ... 27
Table 8–5: Cost-benefit analysis ($M, 2023) – weighted scenarios ... 28
Table 8–6: NPV of net economic benefits ($M, 2023) – lower bound sensitivity (central scenario) ... 28
Table 8–7: NPV of net economic benefits ($M, 2023) – higher bound sensitivity (central scenario) ... 28
Table 8–8: Cost of avoided EUE under the preferred option ($M, 2023) ... 29
Table 10–1: Compliance clauses checklist ... 31

List of figures

Figure 1–1: The RIT-D Process ... 1
Figure 2–1: Supply areas of Fairfield (FF) zone substation - JEN and CitiPower ... 3
Figure 4–1: CBRM Health-Index meaning ... 8
Figure 4–2: Heath-Index of JEN's population of power transformers ... 8
Figure 4–3: FF maximum demand forecast and ratings (MVA) ... 9
Figure 4–4: FF load-duration curve (% of summer and winter maximum demand) ... 10

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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, and under system normal operating conditions.
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, and under system normal operating conditions.
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 370,000 customers covering north-west greater Melbourne.
Maximum Demand	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).
Stand-Alone Power System	An embedded power system that operates disconnected (islanded) from the network.
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 transformers, ancillary equipment and other supporting infrastructure that facilitate the electrical supply to a particular zone

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	in Jemena's electricity network.
10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC, 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, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE condition (winter)	Refers to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

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Abbreviations

ACS	Asset Class Strategy
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFAP	As Far As Practicable
CB	Circuit Breaker
CBRM	Condition-Based Risk Management
CP	CitiPower
DAPR	Distribution Annual Planning Report
DPAR	Draft Project Assessment Report
EDCOP	Electricity Distribution Code of Practice
EPA	Environmental Protection Agency
EUE	Expected Unserved Energy
FF	Fairfield Zone Substation
FPAR	Final Project Assessment Report
HV	High Voltage
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo-Volts
LV	Low Voltage
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
O&M	Operations and Maintenance
POE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
SAPS	Stand-alone Power System
VCR	Value of Customer Reliability

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1. Introduction

This section outlines the purpose of the Regulatory Investment Test for Distribution (**RIT-D**) in relation to the Fairfield Zone Substation (**FF**) supply area, and the structure of this Draft Project Assessment Report (**DPAR**).

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 and 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[3]. The identified need at FF is driven by the increasing reliability of supply risks associated with the deteriorating condition of its No.3 transformer, inhibiting the expansion of the substation to support growth in customer demand, because of the location of this transformer within the switchyard. The capital cost of the most expensive potential credible option to address this need at FF 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, an options screening 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

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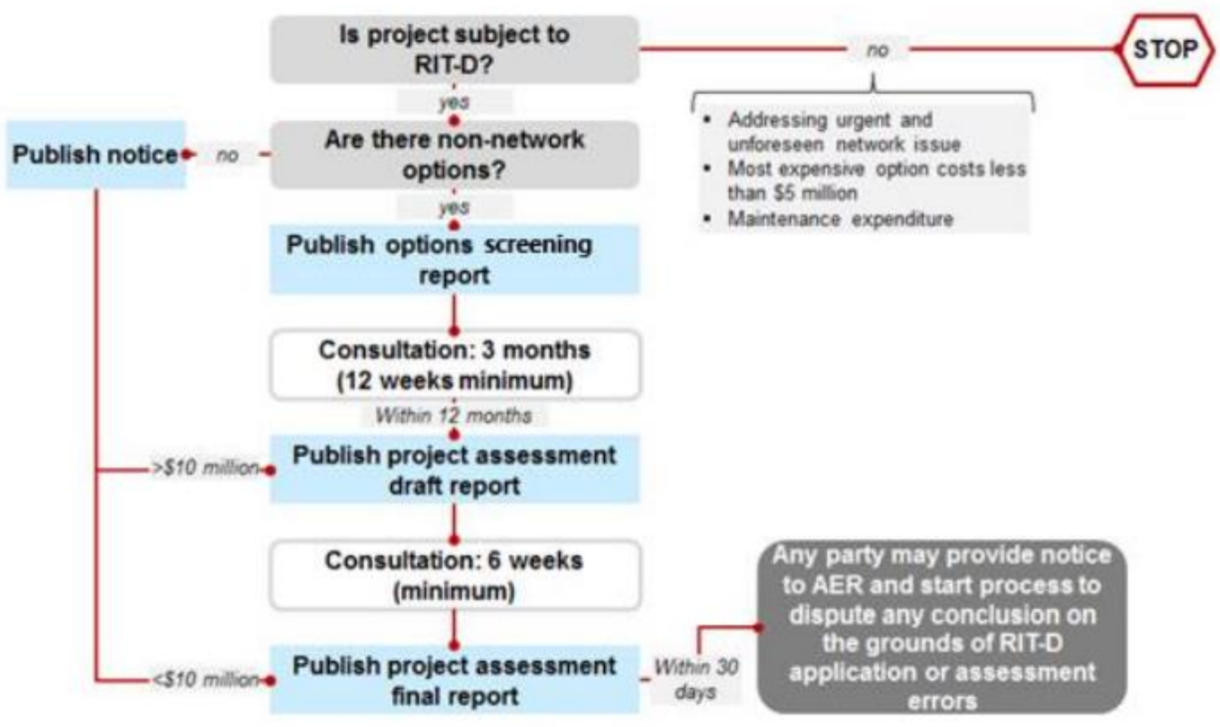
Figure 1–1: The RIT-D Process[4]



3 AER 2021 RIT and APR cost thresholds review (November 2021).

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

For the identified need at FF, a viable non-network or SAPS option would involve implementing measures capable of meeting any shortfall in FF's maximum forecast demand and energy requirements under single contingency conditions of its connected customers, with a maintained level of service. The total requirement at FF from all power sources is 14 MW, which is the shortfall in supplying the 10% probability of exceedance (**POE**) maximum forecast demand at FF in 2033. However, a non-network solution supplying 6 MW may be viable in 2026 if it is accompanied by 1 MW increases in capacity each year thereafter to continue to defer a network solution.

Jemena published an *Options Screening Report Notice of Determination* on its website that analyses the credibility of non-network and SAPS options to address the identified need at FF based on these 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.

1.2 Structure of this report

The objective of this DPAR is to present the results of an economic evaluation that assesses the credible options for addressing the identified need at FF and to identify the preferred option. The contents of this DPAR are:

- Section 2 details the FF supply area;
- Section 3 articulates the identified need in the FF 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 method used to quantify market benefits;
- Section 8 presents the net present value assessment results for the credible options assessed; and
- Section 9 details the technical characteristics of the proposed preferred credible option and next steps.

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2. Background

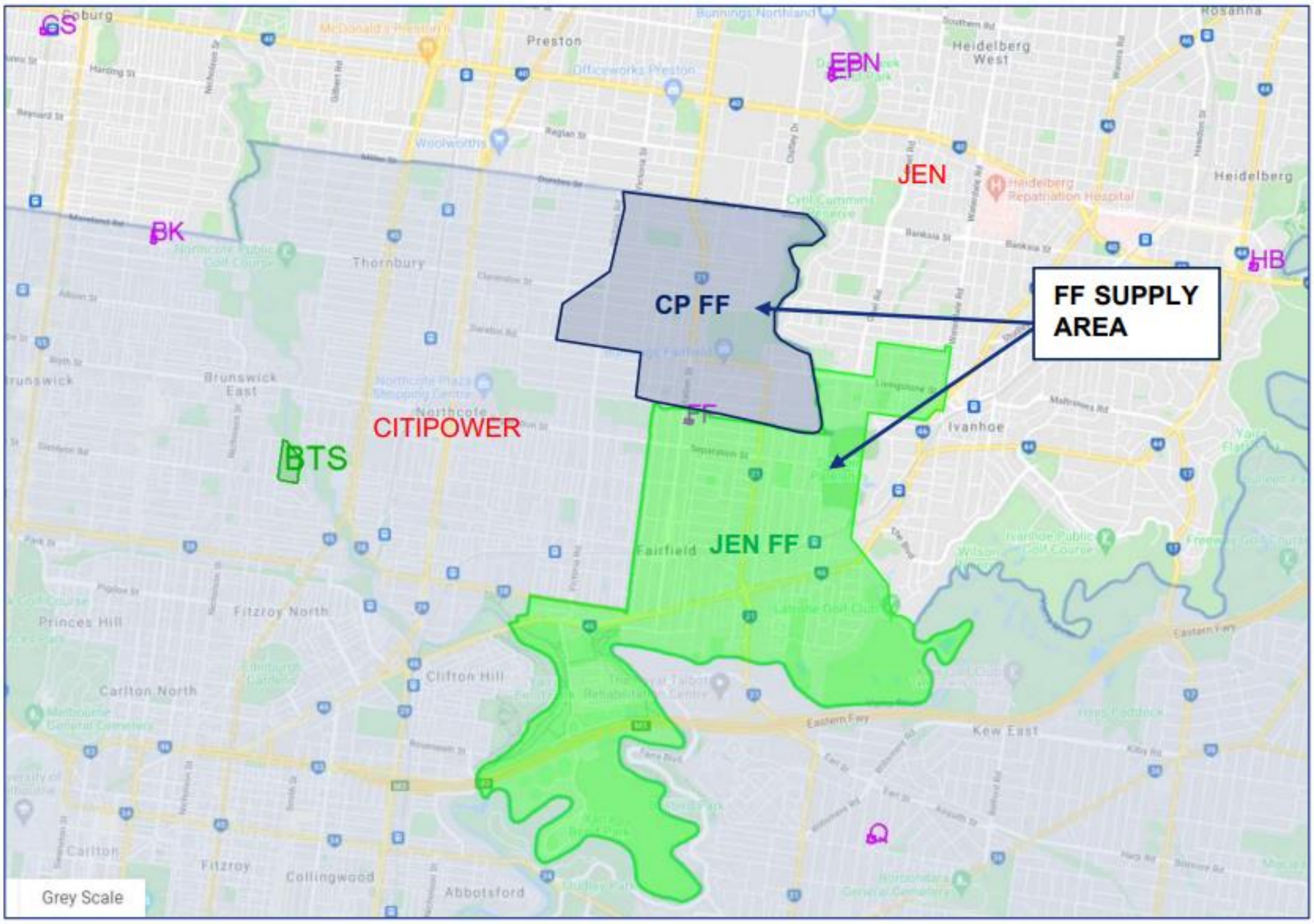
This section provides an overview of the supply area, describes the general arrangement of the Fairfield Zone Substation (**FF**) and gives a brief overview of the network limitations.

2.1 Supply area

Jemena Electricity Networks (Vic) Ltd (**JEN**) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The JEN 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 370,000 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.

FF is owned and operated by Jemena, providing power to approximately 6,756 Jemena customers and 3,664 CitiPower customers (predominantly residential) in the suburbs of Fairfield and Alphington within the JEN supply area, and parts of the suburb of Thornbury within the CitiPower supply area, in Melbourne's inner northeast, through a network of 6.6 kV feeders. Figure 2–1 shows the geographic supply area of FF and its surroundings, including the geographic split between JEN and CitiPower service areas.

Figure 2–1: Supply areas of Fairfield (FF) zone substation - JEN and CitiPower



2.2 Fairfield (FF) zone substation

FF consists of three 22/6.6 kV power transformers and 14 x 6.6 kV feeders from three 6.6 kV indoor bus switchboards. The ratings of the key assets are:

- three transformers rated at 18 MVA (No.1), 18 MVA (No.2) and 13.5 MVA (No.3 on standby) continuous, with cyclic ratings of 21.9 MVA (No.1), 21.9 MVA (No.2) and 14.5 MVA (No.3 on standby);

- three 6.6 kV buses each rated at 2,500 Amps.

The total N nameplate rating of the zone substation is 36.0 MVA. The N-1 rating is based on the transformer cyclic ratings, assuming the No.1 or No.2 transformer is out of service and the No.3 transformer is brought back on load. This gives an N-1 rating of 29.0 MVA.

Given the poor, end-of-life condition of the No.3 transformer, there is a chance it cannot be returned to service to carry load, and therefore the N-2 rating is based on the transformer cyclic ratings, assuming the No.1 or No.2 transformer is out of service and the No.3 transformer is out of service. This gives an N-2 rating of 21.9 MVA.

FF's maximum demand is forecast to increase rapidly over the next several years as a result of some significant customer connections occurring in the southern part of the FF supply area. The FF maximum demand is forecast to be 24.8 MVA for the summer of 2024 under a 10% Probability of Exceedance (**POE**). By 2033 it is forecast that maximum demand will be approximately 36.3 MVA. The highest maximum demand over the 10-year planning horizon is forecast to be 36.3 MVA for summer 2033.

The zone substation assets limiting the summer and winter capacity at FF are the 22/6.6 kV power transformers' thermal limits, and the existing 6.6 kV buses to support additional feeders to meet increasing demand within the FF supply area. Over the 10-year planning horizon, these capacity limits apply under single contingency conditions only.

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There is no load transfer capacity away from FF to surrounding substations. This is because FF operates as a 6.6 kV island, surrounded by distribution networks operating at different voltage levels. This makes FF highly susceptible to long-duration outages for transformer and bus faults under high loading conditions.

At FF, the share of the maximum demand from a total of 10,420 customers forecast to be consuming up to 25 MVA of coincident net load in summer 2024 with approximately 80 GWh of annual energy consumption comprises of:

- 9,632 residential customers consuming 14 MVA peak summer load (average 0.0015 MVA per customer) and 53% of the annual energy consumption.

- 776 commercial customers consuming 8 MVA of peak summer load (average 0.01 MVA per customer) and 42% of the annual energy consumption

- 12 industrial customers consuming 3 MVA of peak summer load (average of 0.25 MVA per customer) and 5% of the annual energy consumption.

3. Identified need

This section articulates the identified need in the FF supply area. Jemena has confirmed FF as a priority for investment based on two key needs:

1. the need to protect power sector workers and members of the public from harm caused by unplanned equipment failure or excessive noise due to deteriorating asset condition (Health and Safety); and,
2. 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).

3.1 Health and safety

The ability to provide a safe network in the FF supply area is being compromised by the poor and deteriorating condition of the FF No.3 transformer. This poses a health and safety risk due to the possibility of asset failure and noise issues.

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 with the objective of minimising risks relating to the condition deterioration of the No.3 transformer at FF. In the short term, Jemena is operating this transformer in a normally off-loaded state to reduce and minimise the risks of noise or a safety incident, until such time the identified need is addressed.

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The need is driven by the poor condition of the 22/6.6 kV 10/13.5 MVA No.3 English-Electric power transformer at FF installed in 1955, which is at risk of failure, posing a safety risk. This transformer is more than 68 years old, one of the oldest on the JEN network, and is showing signs of accelerating deterioration in its condition at the end of its engineering end-of-life.

The potential health and safety risks associated with this poor-condition transformer include:

- Jemena's personnel within the zone substation being exposed to possible transformer failure,
- the public living and working in the vicinity of the zone substation with excessive noise levels, and
- power supply interruptions to our customers.

Replacing or retiring the No.3 transformer is recommended and consistent with regulatory requirements in clause 6.5.7 of the National Electricity Rules (**NER**), and section 3.1 of the Electricity Distribution Code of Practice (**EDCOP**).

Credible solutions would be required to deliver a service that would allow Jemena to decommission, remove and dispose of the existing FF No.3 transformer to maintain the health and safety of Jemena's personnel and the general public.

3.2 Reliability of supply

The No.3 transformer at FF has now been taken off load due to its excessive noise levels breaching Environmental Protection Agency (**EPA**) noise limits and is only put on load when another transformer at FF is taken out of service, either for either maintenance or a forced outage.

Furthermore, there is a current need to extend the 6.6 kV buses at FF to accommodate feeders for additional customer load. However, the location of this existing poor-condition transformer is impeding this expansion of the zone substation to support the requirements of new customers connecting into the FF supply area.

Jemena's planning standard for its zone substation reliability is based on a probabilistic planning approach, which estimates the Expected Unserved Energy (**EUE**) in MWh per annum of customer supply interruptions. The EUE is expressed financially by multiplying it with a Value of Customer Reliability (**VCR**) in $/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 is out of service (called a normal minus one or N-1 scenario, i.e., a contingency condition), taking into account the probability of an asset failure and its restoration times.

While there is presently sufficient capacity to supply the forecast maximum demand at FF with the existing assets that are there, with the poor condition of the No.3 transformer and the lack of spare 6.6 kV feeder bays (on existing 6.6 kV buses), there is a significant deteriorating supply reliability risk under contingency conditions from either another transformer failure or a bus failure. This is because the FF zone substation does not have any distribution feeder tie transfer capacity to surrounding zone substations because it operates as a 6.6 kV island surrounded by distribution networks operating at different voltage levels. Failure of an FF bus or transformer means load could only be transferred to the other buses or transformers at FF, severely limiting the transfer options to restore supply when compared with other zone substations in the network.

A credible option should seek to maintain levels of supply reliability. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply the load under N-1 (single contingency) network conditions, in which the cost of EUE exceeds the annualised cost of the investment. This could be achieved through a range of solutions including:

- meeting the identified need in its entirety through a non-network or SAPS option;
- replacing the No.3 22/6.6 kV transformer with a new transformer located in a different area of the switchyard to accommodate a 4th 6.6 kV bus with new 6.6 kV feeder bays;
- removing the No.3 22/6.6 kV transformer from the site to accommodate a fourth 6.6 kV bus with new 6.6 kV feeder bays, supporting the transformation capacity with a non-network or SAPS option; or
- replacing the No.3 22/6.6 kV transformer with a new transformer and utilising existing 6.6 kV feeder bays by piggybacking cables, supporting the bus capacity with a non-network or SAPS option.

A non-network or SAPS option would need to supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon without the No.3 transformer or fourth bus being available (a level of support of up to 14 MW). This would allow the existing No.3 transformer to be retired completely and removed from the site. Smaller non-network or SAPS solutions of at least 6 MW could provide sufficient capacity to defer the preferred network option.

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4. Assumptions relating to the identified need

This section sets out the key 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 reliability of supply risks at FF 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) associated with the identified need. 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) against the proposed investment cost to mitigate the EUE. 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 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 present value of benefits outweighs the present value of costs 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 FF supply area limitations for this DPAR are outlined in this section, and include maximum demand forecasts, asset condition and capacity ratings, and the associated asset failure rates and consequences.

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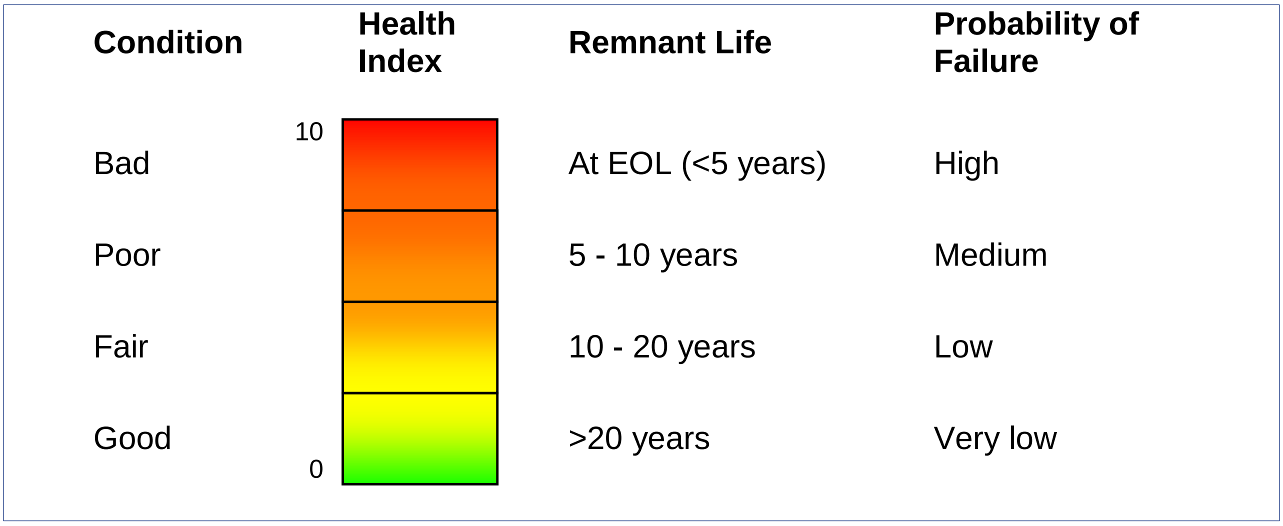
4.1 Asset condition

The asset at FF that is at risk of failure and having excessive noise due to its condition is the No.3 22/6.6 kV power transformer. 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, this asset is assessed to be at a 'high' risk of failure.

CBRM develops a Health-Index for each asset on a scale from 0 to 10. 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 meaning



Health-Index values in excess of 7 represent serious deterioration; i.e., advanced degradation processes now reaching the point that they actually threaten failure, and the rate of further degradation will be relatively rapid.

The condition of the FF No.3 transformer is assessed as having a Health-Index of 8.95 on a scale of 0-10, and is therefore one of the top four worst condition transformers on the JEN network out of a total population of 67 power transformers across the network.

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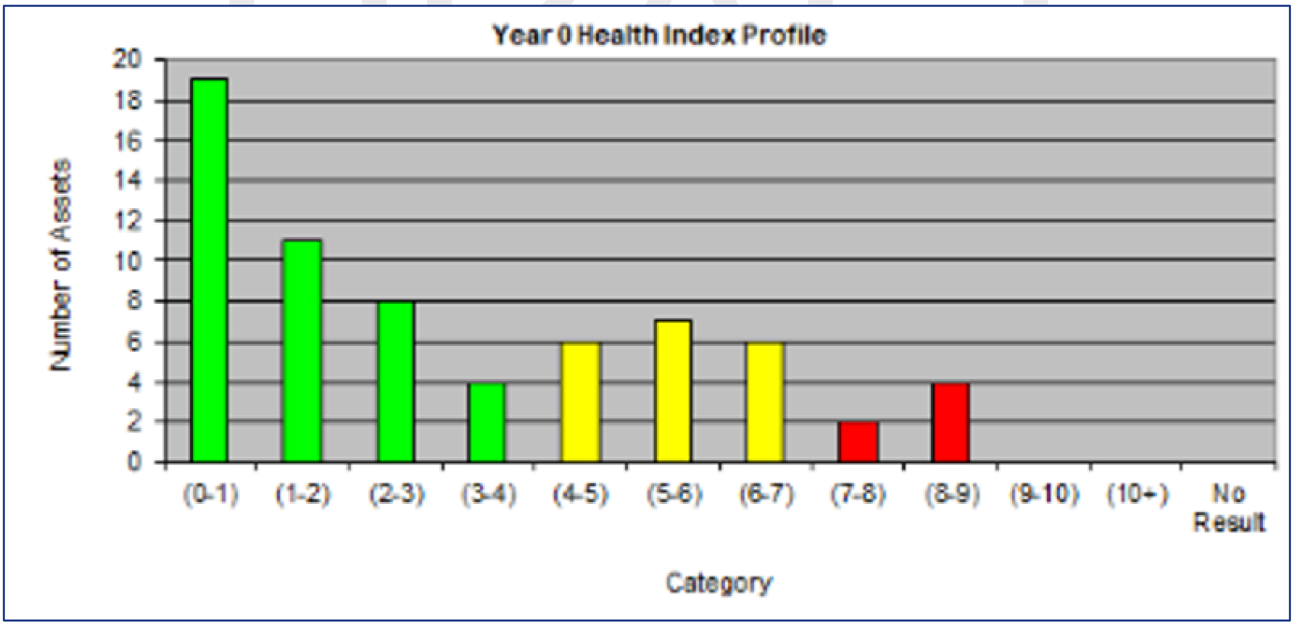
Figure 4–2: Heath-Index of JEN's population of power transformers



The FF No.3 transformer has a moisture content of 31 ppm and a paper insulation DP of 250, both considered to be poor.

The transformer also has a confirmed noise issue with a significant margin up to 22dB(A), and is not compliant with EPA requirements.

4.2 Asset capacity

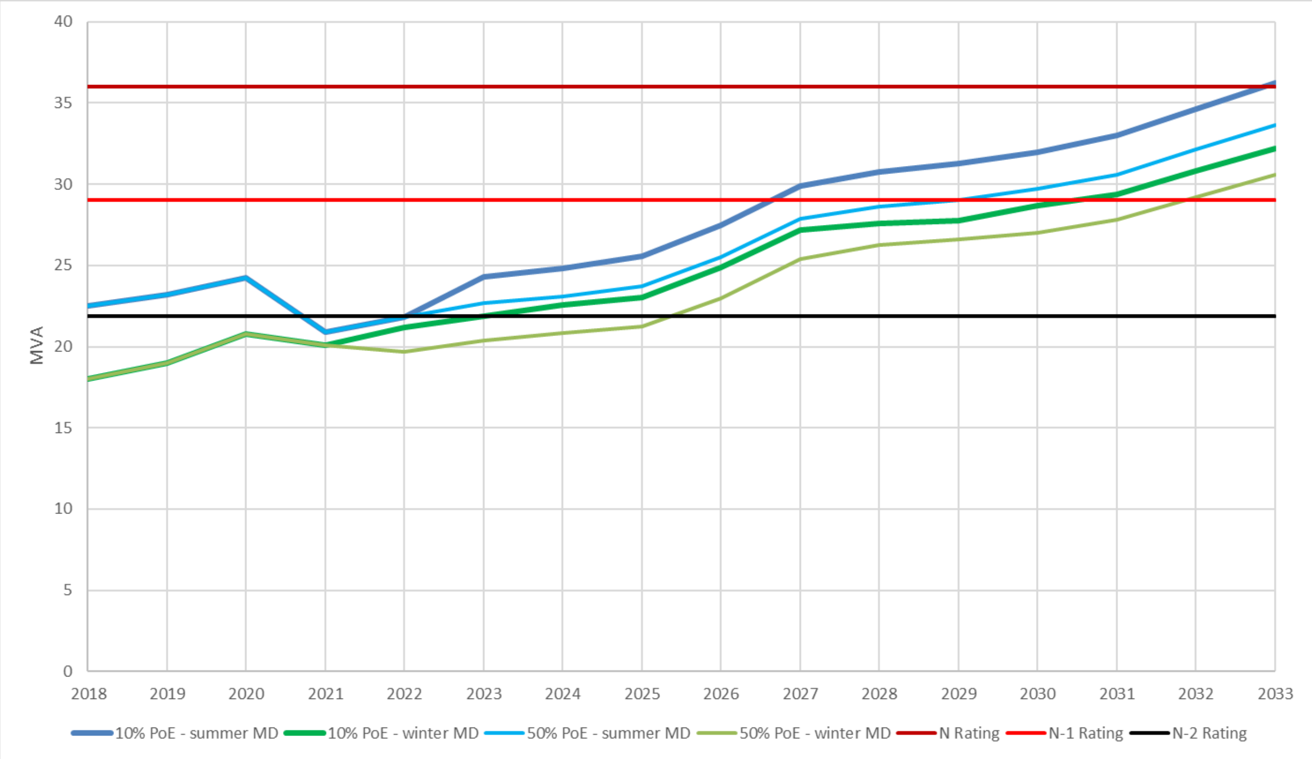
4.2.1 Maximum demand forecasts

The assessment of the reliability of supply from available asset capacity in this DPAR is based on Jemena's 2022 maximum demand forecasts, adjusted by some load uptake advice received from a major customer in early 2023.

The maximum demand forecasts for FF are shown below in Figure 4–3. Maximum demand is forecast to increase rapidly over the next few years as a result of some large customer connections occurring in the southern parts of the FF supply area.

The FF maximum demand is forecast to be 24.8 MVA for the summer of 2024 under a 10% POE. By 2033 it is forecast that maximum demand will be approximately 36.3 MVA.

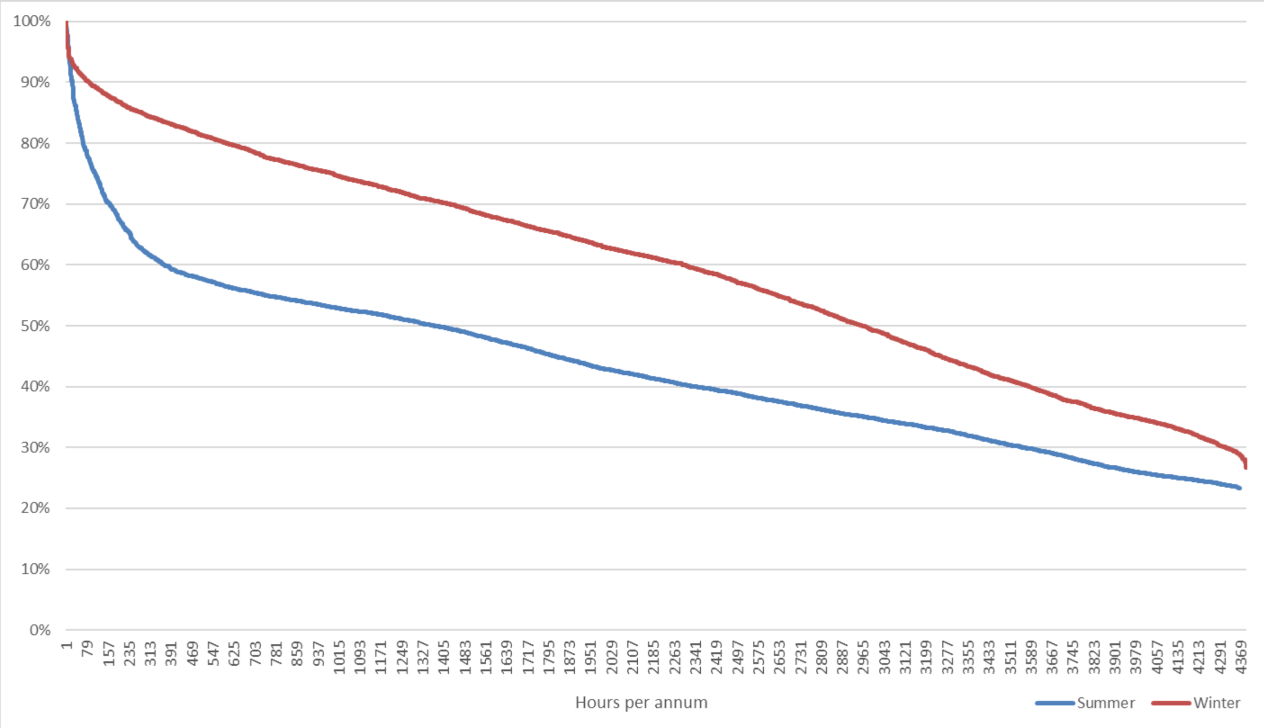
Figure 4–3: FF maximum demand forecast and ratings (MVA)



The highest maximum demand over the 10-year planning horizon is forecast to be 36.3 MVA for summer 2033.

The duration of the demand experienced at FF is illustrated in Figure 4–4.

Figure 4–4: FF load-duration curve (% of summer and winter maximum demand)



Currently, there is no HV-connected embedded generation supplied from FF zone substation. Small LV-connected residential and commercial solar PV comprises approximately 1,260 installations[5] with a capacity of 5 MW, a penetration of 12% of customers.

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4.2.2 Substation capacities

The zone substation assets limiting the summer and winter capacity at FF are the 22/6.6 kV power transformers' thermal limits, and the existing 6.6 kV buses to support additional feeders to meet increasing demand within the FF supply area. Over the 10-year planning horizon, these limits apply under single contingency conditions only.

FF consists of three 22/6.6 kV power transformers, and 14 x 6.6 kV feeders from three 6.6 kV indoor bus switchboards. The ratings of the key assets are:

- three transformers rated at 18 MVA (No.1), 18 MVA (No.2) and 13.5 MVA (No.3 on standby) continuous, with cyclic ratings of 21.9 MVA (No.1), 21.9 MVA (No.2) and 14.5 MVA (No.3 on standby);
- three 6.6k V buses each rated at 2,500 Amps.

The total N nameplate rating of the zone substation is 36.0 MVA.

The N-1 rating is based on the transformer cyclic ratings, assuming the No.1 or No.2 transformer is out of service, and the No.3 transformer is brought back on load. This gives an N-1 rating of 29.0 MVA.

Given the poor, end-of-life condition of the No.3 transformer, there is a chance it cannot be returned to service to carry load, and therefore the N-2 rating is based on the transformer cyclic ratings, assuming the No.1 or No.2 transformer is out of service, and the No.3 transformer is out of service. This gives an N-2 rating of 21.9 MVA.

[5] 935 in the JEN supply area totalling 3.5 MW, and 324 in the CitiPower supply area totalling 1.3 MW.

4.2.3 Transfer capacity

The load transfer capacity away from FF is 0 MVA. This is because it operates as a 6.6 kV island, surrounded by distribution networks operating at different voltage levels. This makes FF highly susceptible to long-duration outages for transformer and bus faults under high loading conditions.

This is the reason why the No.3 transformer remains on site in an off-loaded state so that it can be used to mitigate part of the risk by carrying part of the substation load after a failure of the No.1 or No.2 transformer or a 6.6 kV bus. This No.3 transformer is effectively providing load transfer capacity but the reliability of this transfer capacity will reduce as the transformer condition deteriorates further.

4.3 Quantification of the identified need

The annual value of EUE associated with FF's capacity and its demand profile[6] for a single contingency[7], taking into account asset ratings, probability of failure, repair time and the available transfer capacity, are presented in Table 4–1.

Table 4–1: Value of EUE ($M, 2023) (central scenario)

Year	EUE – Bus	EUE – Transformer	EUE – Total
2024	0.04	0.00	0.04
2025	0.11	0.00	0.11
2026	0.78	0.00	0.78
2027	2.98	0.03	3.02
2028	4.12	0.08	4.20
2029	4.79	0.15	4.95
2030	5.92	0.36	6.27
2031	7.70	0.79	8.49
2032	11.02	1.91	12.92
2033	14.74	3.65	18.39

For the economic evaluation, the value of EUE is assumed to remain at 2033 levels beyond this time.

The driver of the EUE is the lack of available load transfer capacity limiting the ability to restore supply for a single contingency event, for either a transformer or a bus outage at FF. The transformer EUE contribution is comparatively smaller than the bus EUE contribution due to the availability of the No.3 transformer, which can be returned to service in the event of a fault on transformer No.1 or No.2. However due to its deteriorating condition, the availability of the No.3 transformer diminishes over time resulting in a rapid increase in EUE in the later years. The growth in EUE over the period is also driven by the growth in maximum demand over that period.

6 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 FF.

7 EUE is dominated by a failure of a bus or a transformer at FF.

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5. Screening for non-network options

This section sets out the credible non-network and/or SAPS options assessed to address the identified need.

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[8] Section 6.1) are listed below:

- **Demand Management** - 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** - Increased local or distributed generation/supply options, including using capacity for standby power from existing or new embedded generators, or using energy storage systems and load transfer capacity.

It should be noted that generation solutions within a 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. Furthermore, 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.

5.2 Credible non-network 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 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).

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Potential non-network and SAPS scenarios for the FF supply area identified need are:

- **Scenario 1** - Meeting the identified need in its entirety through a non-network or SAPS option, allowing the existing FF No.3 transformer to be completely retired and removed from the site and avoiding the need for a replacement transformer and 4th bus. A non-network or SAPS option would need to supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon, being a level of support up to 14 MW. Smaller non-network or SAPS solutions of at least 6 MW could provide sufficient capacity to defer the preferred network option, increasing the support by 1MW each year.
- **Scenario 2** - Meeting the identified need in part through a non-network or SAPS option, allowing the existing FF No.3 transformer to be completely retired and removed, and coupled with network Option 3[9]. A non-network or SAPS option would need to supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon, being a level of support up to 7 MW. Smaller non-network or SAPS solutions of at least 1 MW could provide sufficient capacity to defer the preferred network option, increasing the support by 1MW each year.

No other scenarios have been identified.

The option screening criteria are applied in the next section.

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

A generation option that can supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon, being a level of support of up to 14 MW from an initial level of 6 MW could comprise of:

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

[9] Refer to Section 6.2.

- 6 MW of generation initially, then 1 MW of generation per annum over 8 years, or
- 14 MW of generation initially,

noting the maximum viable generator size per distribution feeder ranges from 3 MW to 7 MW, based on the ability of JEN's 6.6 kV network to connect the generation.

The support would only be required (for a single contingency) in the event of loss of either the:

- No.1 or No.2 transformer at FF; or
- No.1, No.2 or No.3 bus at FF,

for periods when the demand exceeds the rating of the remaining in-service transformer.

This would enable FF to meet maximum demand in system normal and contingency situations.

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 Capex cost of a small gas-fired generator is approximately $1.25M per MW[10].

For 14 MW of generation, the cost will be over $17.5M. 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.

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This would lead to a lower marginal cost to the customer compared to a network solution cost (of network Option 2) of approximately $22.3M, being the capital cost of replacing the No.3 22/6.6 kV transformer with a new transformer located in a different area of the switchyard and a 4th 6.6 kV bus with new 6.6 kV feeder bays, but this could be offset somewhat by other revenue sources, such as from the market. Additionally, the generation cost estimate does not include the cost of purchasing land in this built-up area, grid connection and operating costs which will likely add up to be significantly higher than the cost of the network solution cost (of network Option 2).

Considering this generation cost estimate does not include the cost of purchasing land in this built-up area, grid connection and operating costs, the cost is likely to be significantly higher than the cost of the preferred network option.

Furthermore, given the existing noise constraints on the No.3 transformer, there are likely to be additional costs for noise mitigation required for a generation solution.

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

5.2.2 Scenario 2 – Non-network or SAPS option to meet identified need in part

Viable generation options that can supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon coupled with network Option 3, being a level of support of up to 7 MW from an initial level of at least 1 MW could comprise of:

- 1 MW of generation initially, then 1 MW of generation per annum over 6 years, or
- 7 MW of generation initially,

[10] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

noting the maximum viable generator size per distribution feeder ranges from 3 MW to 7 MW, based on the ability of JEN's 6.6 kV network to connect the generation.

The support would only be required (for a single contingency) in the event of loss of the:

- No.1 or No. 2 transformer at FF.

for periods when the demand exceeds the rating of the remaining in-service transformer.

This would enable FF to meet maximum demand in system normal and contingency situations.

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 Capex cost of a small gas-fired generator is approximately $1.25M per MW[11].

For 7 MW of generation, the cost will be over $9M. 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 higher marginal cost to the customer compared to a network solution cost (of network Option 4) of approximately $7.80M, being the capital cost of replacing the No.3 22/6.6 kV transformer with a new transformer located in a different area of the switchyard, but this could be offset somewhat by other revenue sources, such as from the market.

Considering this generation cost estimate does not include the cost of purchasing land in this built-up area, grid connection and operating costs, the cost is likely to be significantly higher than the cost of the preferred network option.

Furthermore, given the existing noise constraints on the No.3 transformer, there are likely to be additional costs for noise mitigation required for a generation solution.

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

5.3 Assessment approach and findings

This section reports on the credibility of potential non-network options as alternatives or supplements for the Fairfield network option. 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

[11] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

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Does not meet the criterion	
Does not fully meet the criterion (or uncertain)	
Clearly meets the criterion	

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 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 insolation 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 Generation using gas turbines or diesel				
1.2a Generation using grid-scale renewables (solar)				
1.2b Generation using grid-scale renewables (wind)				
1.3 Standby generation (large customer)				
1.4 Battery energy storage (grid-connected)				
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:

- **Generation using gas turbines or diesel (1.1):**

Identified need - Capable of meeting the identified need by providing multiple gas turbine or diesel generators (met).

Technical - Significant constraints and barriers to deployment of equipment to generate 7 - 14 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 when land, grid 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 processes and the nature of the investment with likely noise and environmental objections, together with design requirements (both for the generators, gas connections and any required 6.6 kV connections to FF) mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

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

Identified need - Unlikely to meet or meaningfully contribute to the identified need. Generation of 7 - 14 MW (the amount required for a viable non-network option) using solar PV is likely to require up to 50 acres of land[12]. Devoting this amount of land to energy production in a dense, urban environment is unlikely to be feasible. As noted in Section 4.2.1, solar PV installations in FF provide a capacity of 5 MW. The amount of solar PV required is more than double or triple this. In addition, the generation profile of solar power will 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 grid-scale solar PV facility to generate 7 - 14 MW in this locality. These include zoning, planning and environmental constraints (given the land requirements), and the lack of evidence of the availability of up to 50 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 Fairfield environment of purchasing up to 50 acres of land are likely to be significant. This is unlikely to be cost-effective when compared to the network alternatives (not met).

Timing - Planning processes and the nature of the investment, together with design requirements (both for the generators and any required 6.6 kV connections to FF) mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

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

Identified need - Unlikely to meet or meaningfully contribute to the identified need. Based on a 2 MW wind turbine requiring 1.5 acres of land[13], a 7 - 14 MW wind farm would require 5 - 10 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).

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

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

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Timing - Planning processes and the nature of the investment with likely height objections, together with design requirements (both for the generators and any required 6.6 kV connections to FF) mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

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

Identified need - As noted in Section 2.2, 12 industrial customers are consuming 3 MVA at the summer peak and 776 commercial customers consuming 8 MVA. It is 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 expanding this to coordinating generation efforts for a larger number of commercial customers 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 the JEN network, which services the northeast of greater metropolitan Melbourne, where there is limited availability of physical space for significantly sized embedded generators and significant environmental limitations. 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 unlikely to be technically feasible within the very small number of existing industrial sites (not met).

Commercial - The estimated cost of a relatively small generator (4 MVA) is about $3.9M and 6.5 MVA about $5.6M both excluding installation and operating costs. To provide the 7 - 14MW needed, 2 to 4 of these would be required. This is unlikely to be commercially viable and too large for customers connected within the 6.6 kV distribution network of FF, given the 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 mean this is unlikely to be completed by 2026 (not met).

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Overall - not a potentially credible option.

- **Battery energy storage (grid-connected) (1.4)**

Identified need - A viable storage option would involve deploying strategically located grid-connected battery energy storage systems totalling 7 – 14 MW, each with an energy-to-power ratio of around 5. (not met).

Technical - This type of technology is technically feasible but would face planning and technical constraints (not fully met).

Commercial - The estimated cost of storage is approximately $1.0M per MWh. For 14 MW of batteries, the cost will be over $70M, excluding land, connection and operating costs, well over any credible network option. (not met).

Timing - Planning processes, the nature of the investment and likely obstacles, together with design requirements mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

5.4.2 Demand management

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 FF 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 (met).

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

Timing - This option could be completed by 2026 (met).

Overall - not a potentially credible option.

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

Identified need - As noted in Section 4.2.1, solar PV customer premises penetration in the FF supply area is around 12% with 5MW of installed capacity. Approximately 1,400 - 2,800 additional FF supply area customers (15 - 30% of remaining customers) would need to have a 5kW solar PV system installed to provide 7 - 14 MW capacity. This rate of take-up is considered to be achievable, but not within the timeframe (not met).

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

Commercial - Achieving a greater than average solar PV 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). 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 2026 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 20 - 40% for the summer peak to achieve a 7 - 14 MW reduction (14 MW / 36 MW[14] = 40%). 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 fully 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 2026 (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 2.3. The targeted nature of the response will allow for the optimisation costs. However, given customer uptake rates of the program are likely to be no higher than 20%, this is insufficient to meet the 7 – 14 MW of demand response needed in the supply area.

Overall - not a potentially credible option.

5.4.3 Findings in the Notice of Determination

The published *Options Screening Report Notice of Determination* associated with this DPAR demonstrated it was unlikely that a non-network or SAPS option could be technically and economically feasible to address the identified

[14] The forecast peak demand in 2033.

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need in this instance. In addition, it demonstrated that there are no combinations of non-network or SAPS options, or non-network and network options, that are likely to adequately address the identified need.

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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.

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 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 No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF;
- Option 3 – Retire No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF; and
- Option 4 – Replace No.3 22/6.6 kV transformer, using existing 6.6 kV buses to piggyback cables.

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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 twenty years. Market benefits for the first ten years (2024-2033) were based on Jemena's amended 2022 maximum demand forecasts. Following on, all market benefits are held constant 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.

7.1.1 Involuntary load shedding and customer interruptions

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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.

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:

- changes in load transfer capacity and the capacity of embedded generators to take up load;
- timing of expenditure;
- voluntary load curtailment;
- costs to other parties;

- option value; and
- electrical energy losses.

7.2.1 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 FF supply area. This assessment showed there was insufficient potential for generation or storage to materially address the need.

Furthermore, the FF supply area does have any level of load transfer capacity to adjacent supply areas that can reduce the reliability impacts of an asset failure at FF and is therefore not considered to be relevant for differentiating between options that address the identified need in the FF supply area.

7.2.2 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 for differentiating between options that address the identified need in the FF supply area.

7.2.3 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.

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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 FF 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 for differentiating between network options.

7.2.4 Cost to other parties

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

7.2.5 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 FF supply area, it is noted that a safety need including noise compliance issues has been identified. As explained in Section 5.2, a credible solution must enable the retirement and removal of the poor condition No.3 transformer at FF.

It is therefore considered that in this case, there is little value in retaining flexibility, given that the safety need requires decommissioning and removal of the existing No.3 transformer at FF. Jemena has therefore not attempted to estimate any additional option value market benefit for this RIT-D assessment.

7.2.6 Electrical energy losses

Reducing network utilisation, through network impedance or load changes in the FF supply area could result in a change in network losses. The network options are, however, 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.

7.3 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.

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7.3.1 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.

7.3.2 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[15] published in December 2019. Therefore, the composite VCR for FF has been derived as shown in Table 7–1, escalated by CPI to 2023.

Table 7–1: Base case VCR for FF

Sector	AER VCR ($/kWh)	Annual Energy consumption (%)	Energy Consumption weighted VCR ($/kWh)
Residential[16]	21.25	53	11.26
Agricultural	37.87	0	0.00
Commercial	44.52	42	18.70
Industrial	63.79	5	3.19
Composite of all sectors			33.15
Composite of all sectors (indexed to 2023)			**36.80**

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

[16] Climate zone 6, CBD and Suburban.

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

7.3.3 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 old plant, and scrap value where appropriate.

7.3.4 Discount rate

A base case discount rate of 7.0%[17] 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 7–2.

7.3.5 Asset failure rate assumptions

The base case failure rates assumed in the analysis are 1% per annum for each of the No.1 and No.2 transformers and 0.5% per annum for each 6.6 kV bus. Jemena does not hold any spare 22/6.6 kV transformers or 6.6 kV buses.

At a Health-Index of 8.95 as described in Section 3.1, the No.3 transformer is currently expected to have a failure rate of approximately 60% when on load, and this is expected to reach 100% within ten years. Sensitivities to the failure rates of ±30% have been considered.

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7.3.6 Summary of sensitivity assumptions

Table 7–2 summarises the sensitivities of key variables tested in this DPAR.

Table 7–2: 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	4.0%	7.0%	9.0%
Asset failure rate	70%	100%	130%

[17] Discount rates are based on an indicative commercial discount rate from Table 28 of AEMO 2023 Inputs, Assumptions and Scenarios Report (Draft), dated December 2022. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/draft-2023-inputs-assumptions-and-scenarios-report.pdf?la=en

7.4 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. 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 which determine the value of the EUE.

Table 7–3: Scenarios

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

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8. Options analysis

This section presents the base case limitations 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 2024 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).

8.1 Option 1 – Do nothing (base case)

This option considers the impact of a 'Do nothing' base case, which would include no additional investment in FF (beyond any previously committed investment). Involuntary load shedding may result from unplanned asset failures and associated health and safety risk consequences. The impact of these network limitations under the base case is presented in Table 8–1 below, for each type of single contingency and in the aggregate.

Table 8–1: Do nothing – present value of EUE ($M, 2023)

Option 1	Low Scenario	Central Scenario	High Scenario	Weighted Total
Transformers	0.0	18.9	57.0	23.7
Buses	33.1	92.9	148.4	91.8
EUE Cost	**33.1**	**111.8**	**205.4**	**115.5**

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The driver of the EUE is the lack of available load transfer capacity limiting the ability to restore supply for a single contingency event, for either a transformer or a bus outage at FF. The transformer EUE contribution is comparatively smaller than the bus EUE contribution due to the availability of the No.3 transformer, which can be returned to service in the event of a fault on transformer No.1 or No.2. However due to its deteriorating condition, the availability of the No.3 transformer diminishes over time.

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

8.2 Option 2 – Replace No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF

Option 2 involves replacing the No.3 22/6.6 kV transformer with a new 22/6.6 kV 18 MVA transformer located in a different area of the switchyard and installing a 4th 6.6 kV bus with new 6.6 kV feeder bays, with the cost of unplanned asset failure represented by a lower value of EUE compared to Option 1.

Table 8–2: Option 2 – present value of residual EUE ($M, 2023)

Option 2	Low Scenario	Central Scenario	High Scenario	Weighted Total
Transformers	0.0	0.0	0.0	0.0
Buses	0.0	0.0	0.0	0.0
EUE Cost	**0.0**	**0.0**	**0.0**	**0.0**

There is no residual EUE for this option compared to Option 1, meaning it fully addresses the identified need.

The capital cost of Option 2 is approximately $22.3M ($2023 real) with an ongoing operating cost of $0.22M pa.

8.3 Option 3 – Retire No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF

Option 3 involves retiring the No.3 22/6.6 kV transformer and removing it from the site (without replacing it) to accommodate a 4th 6.6 kV bus with new 6.6 kV feeder bays, with the cost of unplanned asset failure represented by a lower value of EUE compared to Option 1.

Table 8–3: Option 3 – present value of residual EUE ($M, 2023)

Option 3	Low Scenario	Central Scenario	High Scenario	Weighted Total
Transformers	0.7	21.4	62.4	26.5
Buses	5.7	24.5	45.5	25.1
EUE Cost	**6.4**	**45.9**	**107.9**	**51.5**

Whilst the residual EUE for the bus contribution has reduced for this option with the installation of another bus, the transformer contribution is higher than Option 1 due to the removal of the No.3 transformer from the site. As such it would no longer be able to be returned to service to carry load for a fault on transformer No.1 or No.2.

The capital cost of Option 3 is approximately $14.5M ($2023 real) with an ongoing operating cost of $0.15M pa.

8.4 Option 4 – Replace No.3 22/6.6 kV transformer, using existing 6.6 kV buses to piggyback cables

Option 4 involves replacing the No.3 22/6.6 kV transformer with a new 22/6.6 kV 18 MVA transformer and utilising the existing 6.6 kV feeder bays by piggybacking any new feeder cables that will be needed to support customer demand growth in the FF supply area, with the cost of unplanned asset failure represented by a lower value of EUE compared to Option 1.

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Table 8–4: Option 4 – present value of residual EUE ($M, 2023)

Option 4	Low Scenario	Central Scenario	High Scenario	Weighted Total
Transformers	0.0	0.0	0.0	0.0
Buses	33.1	92.9	148.4	91.8
EUE Cost	**33.1**	**92.9**	**148.4**	**91.8**

This option completely addresses the single contingency risk at FF for a transformer fault, but has no impact on the residual EUE for bus faults compared to Option 1.

The capital cost of Option 4 is approximately $7.8M ($2023 real) with an ongoing operating cost of $0.08M pa.

8.5 Net economic benefits

The economic analysis shown in Table 8–5, based on the scenario weightings, demonstrates that Option 2 provides the highest present value of net economic benefits and is therefore likely to be the preferred option.

Table 8–5: Cost-benefit analysis ($M, 2023) – weighted scenarios

Option	Capital cost	Present value of capital and O&M	Present value of EUE	Present value of benefits	NPV	Ranking
Option 1 - Do nothing (base case)	(0.0)	(0.0)	(115.5)	0.0	0.0	4
Option 2 - Replace No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF	(22.3)	(21.9)	(0.0)	115.5	93.6	1
Option 3 - Retire No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF	(14.5)	(13.9)	(51.5)	64.0	50.1	2
Option 4 - Replace No.3 22/6.6 kV transformer, using existing 6.6 kV buses to piggyback cables	(7.8)	(8.0)	(91.8)	23.7	15.7	3

8.6 Sensitivity analysis

A set of sensitivities were defined in section 7.3 to test the robustness of the NPV of the central scenario to changes in key assumptions. The sensitivity analysis demonstrated that the conclusion of Option 2 being the preferred option was not sensitive to the changes, as the ranking of the options remained constant as shown in Table 8–6 and Table 8–7 below.

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Table 8–6: NPV of net economic benefits ($M, 2023) – lower bound sensitivity (central scenario)

Sensitivity	Option 2	Option 3	Option 4	Option 2 Ranking
Nil	89.9	52.0	10.9	1
Maximum demand forecast	31.7	30.4	(7.0)	1
Value of customer reliability	86.1	52.5	7.1	1
Capital cost	96.5	56.1	13.3	1
Discount rate	142.9	84.1	20.2	1
Asset failure rate	44.5	20.5	(6.2)	1

Table 8–7: NPV of net economic benefits ($M, 2023) – higher bound sensitivity (central scenario)

Sensitivity	Option 2	Option 3	Option 4	Option 2 Ranking
Nil	89.9	52.0	10.9	1
Maximum demand forecast	134.2	58.7	34.3	1
Value of customer reliability	93.7	51.5	14.6	1
Capital cost	83.3	47.8	8.4	1
Discount rate	77.1	46.9	8.2	1
Asset failure rate	124.5	72.9	17.6	1

8.7 Preferred option optimal timing

The optimal timing of the preferred option 2 occurs when its annualised cost exceeds the combined annual cost of the avoided EUE of Option 1 (do nothing).

The annualised cost of option 2 is approximately $0.96 million per annum. This is exceeded by the cost of the avoided EUE in summer 2026-27 under the weighted scenario as shown in Table 8–8.

Table 8–8: Cost of avoided EUE under the preferred option ($M, 2023)

Year	Low Scenario	Central Scenario	High Scenario	Weighted Total
2024	0.0	0.0	0.3	0.09
2025	0.0	0.1	0.5	0.18
2026	0.0	0.8	**2.1**	0.92
2027	0.6	**3.0**	**6.5**	**3.29**
2028	**1.0**	**4.2**	**8.8**	**4.55**

Taking into account a 2-year lead time for implementation of option 2, the optimal completion date is in 2026.

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9. Conclusion and next steps

The assessment outlined within this report shows that the primary limitations associated with the FF supply area are the concerns around the safety and noise levels of the deteriorating, poor condition No.3 transformer at FF and the impact on the level of supply reliability as a result of the location of that asset impeding the expansion of the FF switchyard to support growth in customer demand.

This section details the technical characteristics of the proposed preferred option and the next steps.

9.1 Preferred option

The proposed preferred option is Option 2 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 reliability of supply risk from the base case. Option 2 satisfies the requirements of the RIT-D.

The proposed preferred option involves replacing the existing FF No.3 22/6.6 kV transformer with a new 22/6.6 kV 18 MVA transformer located in a different area of the switchyard, and installing a 4th 6.6 kV bus with new 6.6 kV feeder bays in the location of the existing transformer at a capital cost of $22.3 million (real $2023), with a completion date in 2026. As a part of this option, the following major assets will be installed:

- Replacing the existing No.3 22/6.6 kV power transformer, by removing it from the site and installing a new 22/6.6 kV 18 MVA power transformer in another location of the switchyard;
- Installing a new 4th 6.6 kV bus with new 6.6 kV feeder bays in the location of the existing No.3 22/6.6 kV power transformer;
- Other primary assets needed to support the connection of the replaced transformer and new 6.6 kV bus; and
- Associated protection and control relays and other secondary assets which monitor, control and protect the above assets.

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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:

Hung Nguyen
Senior Network Planning Engineer
Email: PlanningRequest@jemena.com.au
Phone: (03) 9173 7960

Submissions should be lodged with us on or before 6 October 2023.

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

Following consideration of any submissions on this DPAR, Jemena will proceed to prepare a Final Project Assessment Report (**FPAR**). That report will include a summary of, and commentary on, any submissions to this DPAR, and present the final preferred option to address the identified need. Publishing the FPAR will be the final stage of the RIT-D process.

Jemena intends to publish the FPAR by 20 October 2023. Note that if no submissions are received on this report, Jemena will discharge its obligation to publish the FPAR, and instead include the final decision in the 2023 Distribution Annual Planning Report.

10. Appendix A – Checklist of compliance clauses

Table 10–1 presents a checklist of the NER clause 5.17.4(j) and references the section within this DPAR where those clauses are addressed.

Table 10–1: Compliance clauses checklist

Clause	Section
(1) a description of the identified need for the investment;	0
(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;	7.1
(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;	7.2
(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;	8
(6) quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	8
(9) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	8.5
(10) the identification of the proposed preferred option;	9.1
(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	9.1
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed	9.2

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