Jemena Electricity Networks (Vic) Ltd

Brunswick - Fairfield Subtransmission Loop Capacity Constraint

RIT-D Stage 1: Non-Network Options Report

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Name	Job Title	Date	Signature
Reviewed by:			
Andy Dickinson	Future Network & Planning Manager	15/09/2021	Endorsed via email
Approved by:			
Karl Edwards	General Manager Asset & Operations	21/09/2021	Endorsed via email

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Executive Summary

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

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

Identified need

Jemena's Fairfield Zone Substation (**FF**), located at the corner of Station St and McGregor St, supplies approximately 6,621 JEN customers and 3,664 CitiPower customers (predominantly residential) at 6.6 kV in Fairfield and Alphington in the JEN supply area, and parts of Thornbury in the CitiPower supply area. The Zone Substation is supplied by three 22 kV subtransmission lines that originate from AusNet Services' Brunswick Terminal Station (**BTS**).

Electricity demand in the FF supply area is expected to grow on average at 4.3% per annum over the next five years. The expected increase in demand is mainly driven by the current and proposed residential and commercial developments at the former Amcor Paper Fairfield site, known as YarraBend.[1] Although there is enough transformation capacity at FF, the existing 22 kV subtransmission lines supplying FF from BTS are currently fully utilised and will not have sufficient capacity to meet the increasing demand.

The subtransmission lines are currently operating above their N-secure rating.[2] Under the worst case single contingency condition, the loading on the subtransmission lines reaches 126% utilisation, which will require JEN to take customers off supply. Based on the current forecast on a single contingency event for summer 2021-22, approximately 6.8 MVA of load will be shed around the Fairfield and Alphington area to maintain operation of the lines within their thermal safe loading limits. This will leave approximately 2,600 customers off supply during an outage on the subtransmission line. In addition, all three subtransmission lines are sharing the same pole line with another line (from the same loop) for all or part of the route, increasing the likelihood of single outage taking out two of the three 22 kV lines. In the event of this outage condition, this will leave approximately 6,200 customers off supply.

Table OV-1 shows the forecast utilisation for the most onerous subtransmission line 10% PoE summer and winter conditions. The forecast utilisation for less onerous conditions is presented in Section 3.

Table OV-1: BTS- FF Subtransmission line forecast utilisation

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Summer N condition	78%	79%	82%	87%	92%	95%	97%	99%	100%	100%
Summer N-1 condition	126%	129%	134%	142%	150%	156%	159%	163%	164%	164%
Winter N condition	57%	58%	61%	65%	69%	71%	73%	74%	74%	75%
Winter N-1 condition	93%	95%	99%	106%	111%	115%	118%	121%	122%	123%

1 See https://yarrabend.com.au/.

2 JEN acceptable loading on the subtransmission line under system normal to maintain supply reliability during single contingency (N-1) condition.

Options analysis and preferred network option

JEN has identified below potential credible options to alleviate the current and emerging constraints on the BTS-FF 22 kV subtransmission lines:

- Option 1: Do nothing[3] (base case);
- Option 2: Reinforce supply to FF and surrounding areas from the adjacent Heidelberg (**HB**) substation. This will assist in reducing the load-at-risk on the BTS-FF lines;
- Option 3: Install a capacitor bank at FF. This option will marginally reduce the load-at-risk on the BTS-FF lines by reducing network losses and improving the power factor;
- Option 4: Augment the BTS-FF subtransmission loop by installing a new fourth line from BTS to FF. This will assist in reducing the load-at-risk on the BTS-FF lines; and
- Option 5: Non-network options including embedded generation and demand management.

Based on our preliminary analysis, it appears that Option 4, which is to install a fourth 22 kV subtransmission line from BTS to FF at a cost of $6.78 million,[4] is the preferred network option. Our initial indicative estimate suggests that the value of this network augmentation deferral associated with this option would be approximately $418,000[5] per annum.

Next steps

The purpose of this report is to identify credible non-network options that may provide a more cost-effective solution than Option 4. To assist non-network proponents, we have presented the technical characteristics of our network needs for managing utilisation on the BTS-FF subtransmission lines. Importantly, this information is only intended to guide non-network proponents in developing credible non-network options. JEN welcomes an open dialogue with non-network proponents to identify potential alternatives to the network options identified in this report. JEN invites written submissions from interested parties, including proponents of non-network solutions on the matters set out in this report.

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 15 December 2021.

In light of submissions in response to this Non-Network Options Report, we will proceed to prepare a more detailed Draft Project Assessment Report (**DPAR**). That report will apply the latest available information on demand forecasts, VCR estimates and project cost estimates to assess the network and non-network solutions.

[3] Do nothing materially different, per the AER's industry practice application note for asset replacement planning, January 2019, p. 27.

[4] Real June 2021 dollars, capital cost.

[5] Real June 2021 dollars, annualised cost of augmentation including additional O&M.

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Glossary

Constraint	Refers to a constraint on network power transfers that affects customer service.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, JEN is 100% owned by Jemena and services over 355,000 customers via a 6,630-kilometre distribution system covering northwest greater Melbourne.
Maximum demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network’s ability to transfer electricity to customers.
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.
Probability of exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Distribution (RIT-D)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a prescribed limit in the National Electricity Market (NEM).

Abbreviations

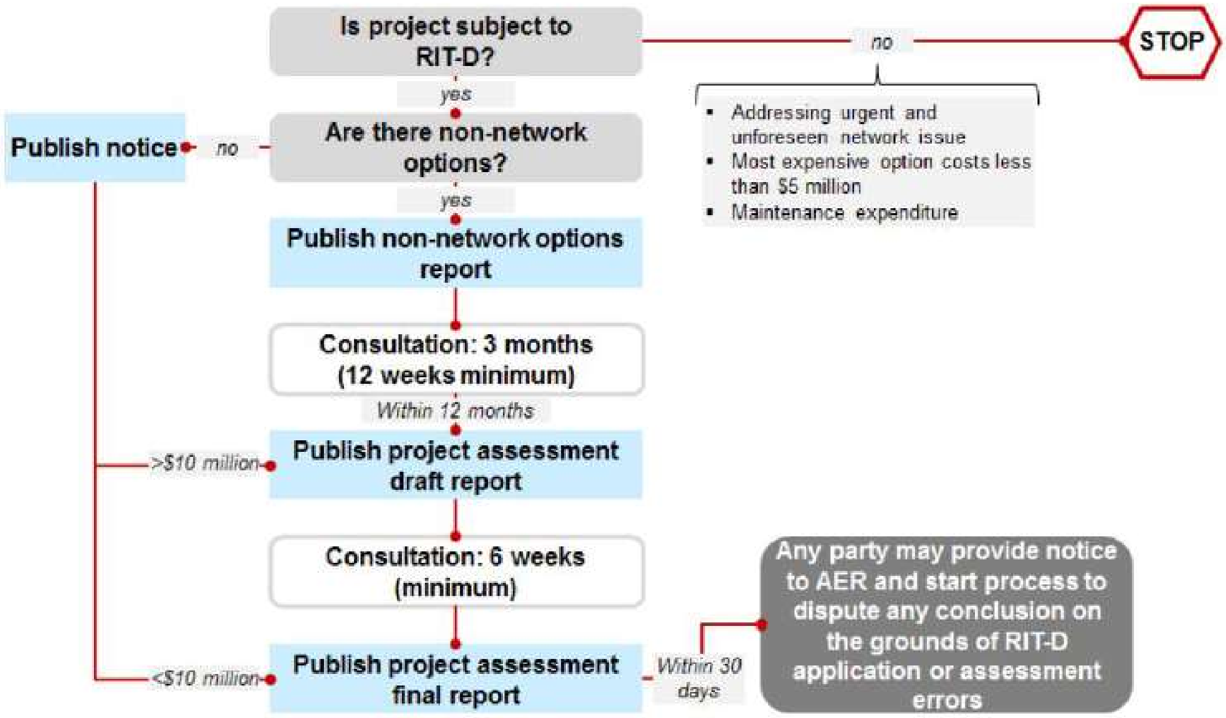
1C	1-core
3C	3-core
AER	Australian Energy Regulator
Al	Aluminium
BTS	Brunswick Terminal Station (owned by AusNet Services)
CB	Circuit Breaker
EP	East Preston Zone Substation
EUE	Expected Unserved Energy
FF	Fairfield Zone Substation
HB	Heidelberg Zone Substation
HV	High Voltage
JEN	Jemena Electricity Network
LV	Low Voltage
MD	Maximum Demand
NC	Northcote Zone Substation (owned by CitiPower)
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
O&M	Operations and Maintenance
POE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
TSTS	Templestowe Terminal Station (owned by AusNet)
VCR	Value of Customer Reliability
XLPE	Cross linked polyethylene

1. Introduction

1.1 Purpose

DNSPs are required to go through a process (the Regulatory Investment Test for Distribution, or "**RIT-D**") to identify investment options that best address an identified need on the network. 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.[6] As part of the RIT-D process, DNSPs must also consider non-network options when assessing credible options to address the identified need. The RIT-D process is summarised in Figure 1-1.

Figure 1–1: The RIT-D Process[7]



Under the RIT-D consultation procedures, DNSPs are required to prepare and publish a Non-Network Options Report. This report helps DNSPs to identify potential non-network options and be better informed on the costs and market benefits associated with a potential option. These arrangements provide an opportunity for third parties to consider how they could address the DNSP's identified need on the network.

This document is JEN's Non-Network Options Report for the needs associated with the BTS-FF subtransmission loop. In accordance with the requirements of clause 5.17 of the National Electricity Rules (**NER**), this report:

- describes the identified need in relation to the BTS-FF 22 kV subtransmission loop;
- identifies the potential credible network options that Jemena considers could address the identified need;
- specifies the technical characteristics of a non-network option to address the identified need; and
- invites submissions from interested parties.

[6] In accordance with the Australian Energy Regulator (**AER**) Final Application Guidelines RIT-D (14 December 2018), from 1 January 2019 this cost threshold has been changed to $6 million.

[7] Source: AER Final Application Guidelines RIT-D (14 December 2018).

1.2 Objective of this report

JEN's objective is to ensure that reliable distribution services are delivered at the highest net benefit to our customers. Non-network solutions have an important role to play in meeting this objective. This report is an initial step in our engagement with non-network proponents in addressing the identified need in relation to the BTS-FF 22 kV subtransmission loop. Jemena welcomes an open dialogue with non-network proponents to ensure that the best solution is adopted, whether that solution is a network, non-network or combined project.

1.3 Definitions

Non-network options include (AER's Application Guidelines Section 6.1):

- any measure or program targeted at reducing peak demand (e.g., automatic control schemes, energy efficiency programs, or smart meters and associated cost-reflective pricing);
- increased local or distributed generation or supply options (e.g., capacity for standby power from existing or new embedded generators or using energy storage systems and load transfer capacity).

An identified need is defined in Chapter 10 of the NER as the objective a network service provider (**NSP**) seeks to achieve by investing in the network.

According to the AER's Application Guidelines (Section 3.1), an identified need may be addressed by either a network or a non-network option and:

- May consist of an increase in the sum of consumer and producer surplus in the NEM, or an identified need may be for reliability corrective action as per NER 5.17.1(b), where the NER 5.10.2 defines reliability corrective action as a NSP investment in its network to meet the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options.
- RIT-D proponents should express an identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. This objective should be expressed as a proposal to electricity consumers and be clearly stated and defined in the RIT-D report. Framing the identified need as a proposal to consumers should assist the RIT-D proponent in demonstrating why the benefits to consumer would outweigh the costs. A description of an identified need should not mention or explain a particular method, mechanism or approach to achieve a desired outcome.

A credible option is defined in Clause 5.15.2(a) of the NER as an option or group of options that:

- addresses (or address) the identified need;
- is (or are) commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need.

NER Clause 5.15.2(c) conveys that: In applying the regulatory investment test for distribution, the RIT-D proponent must consider all options that could be reasonably classified as credible options without bias to:

- energy source;
- technology;
- ownership; and
- whether it is a network or non-network option.

JEN has interpreted the guidance to mean that a credible option could also consist of a non-network component and a network component, which combined meet the identified need (e.g., where a non-network solution reduces peak demand so that the RIT-D proponent can install smaller capacity or less costly equipment (AER's Application Guidelines Example 22, page 73)).

1.4 Structure of this report

The remainder of this report is structured as follows:

- Section 2 provides background information on the network location and assets;
- Section 3 describes the identified need that is to be addressed;
- Section 4 summarises the method and assumptions employed in assessing the credible options;
- Section 5 sets out the credible network options and provides an indicative assessment of their respective augmentation costs;
- Section 6 provides the summary of economic analysis of network options and recommended preferred network option;
- Section 7 presents the technical characteristics of the identified need, which should guide non-network proponents in developing credible non-network options; and
- Section 8 sets out our contact details and provides a guide as to the information that non-network proponents should submit in response to this report. The section also outlines the next steps in the assessment process.

2. Background

This section provides an overview of the Fairfield and Alphington supply area, and describes the general arrangement of Fairfield Zone Substation (FF) and associated subtransmission lines.

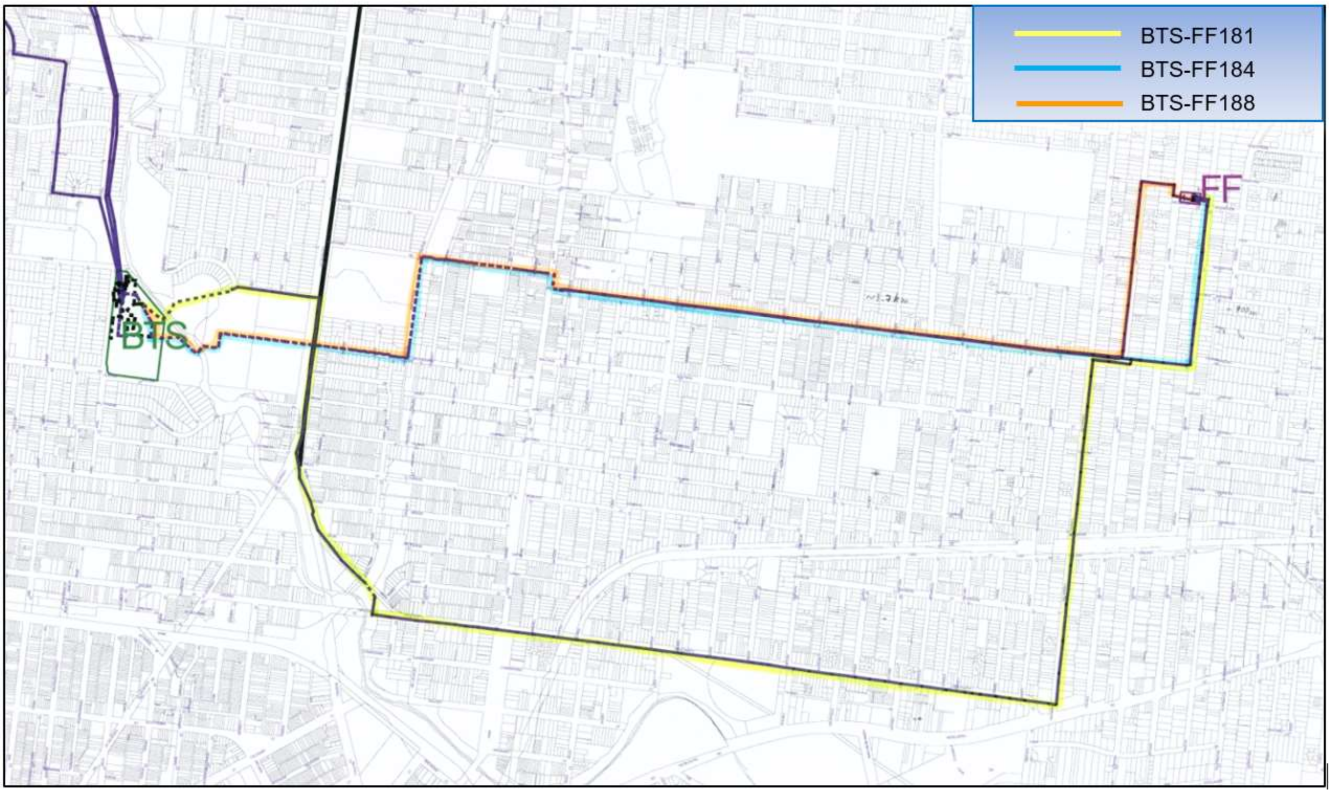
2.1 Network supply arrangement current state

BTS-FF subtransmission loop

Electricity supply to JEN's Fairfield Zone Substation (FF) is provided by three 22 kV subtransmission lines (BTS-FF 181, BTS-FF 184 and BTS-FF 188) supplied from AusNet Services' Brunswick Terminal Station (BTS). All three subtransmission lines share the same pole line with another line (from the same loop) for all or part of the route, increasing the likelihood of single outage taking out two of the three 22 kV lines.

Figure 2–1 shows the route map of the subtransmission lines between BTS and FF.

Figure 2–1: Geographic map of the BTS-FF 22 kV subtransmission lines



FF Zone Substation

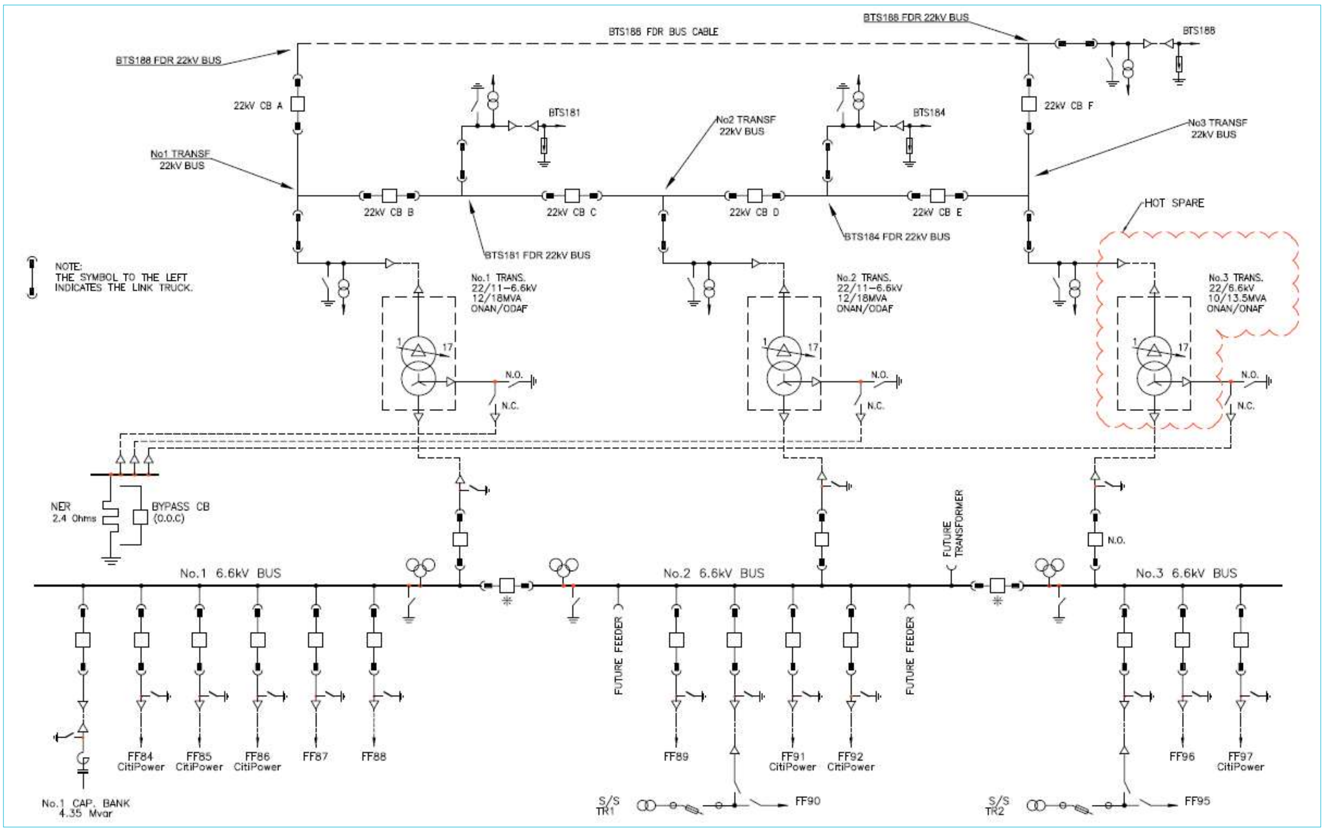
FF currently has two 22/11-6.6 kV 12/18 MVA dual winding transformers (replaced in 2020) and one 22/6.6 kV 10/13.5 MVA single winding transformer (as a hot-spare[8]), a 2.4 Ω neutral earthing resistor and twelve 6.6 kV feeder circuit breakers.

Being very close to the CitiPower boundary, six of the 6.6 kV feeders from FF cross the boundary line and supply approximately 3,664 CitiPower customers. The remaining six feeders supply approximately 6,621 customers in JEN's distribution area.

8 There are some noise issues with this transformer that are is currently being reviewed and assessed.

Figure 2–2 presents a single line diagram of FF.

Figure 2–2: Fairfield Zone Substation (FF) single line diagram



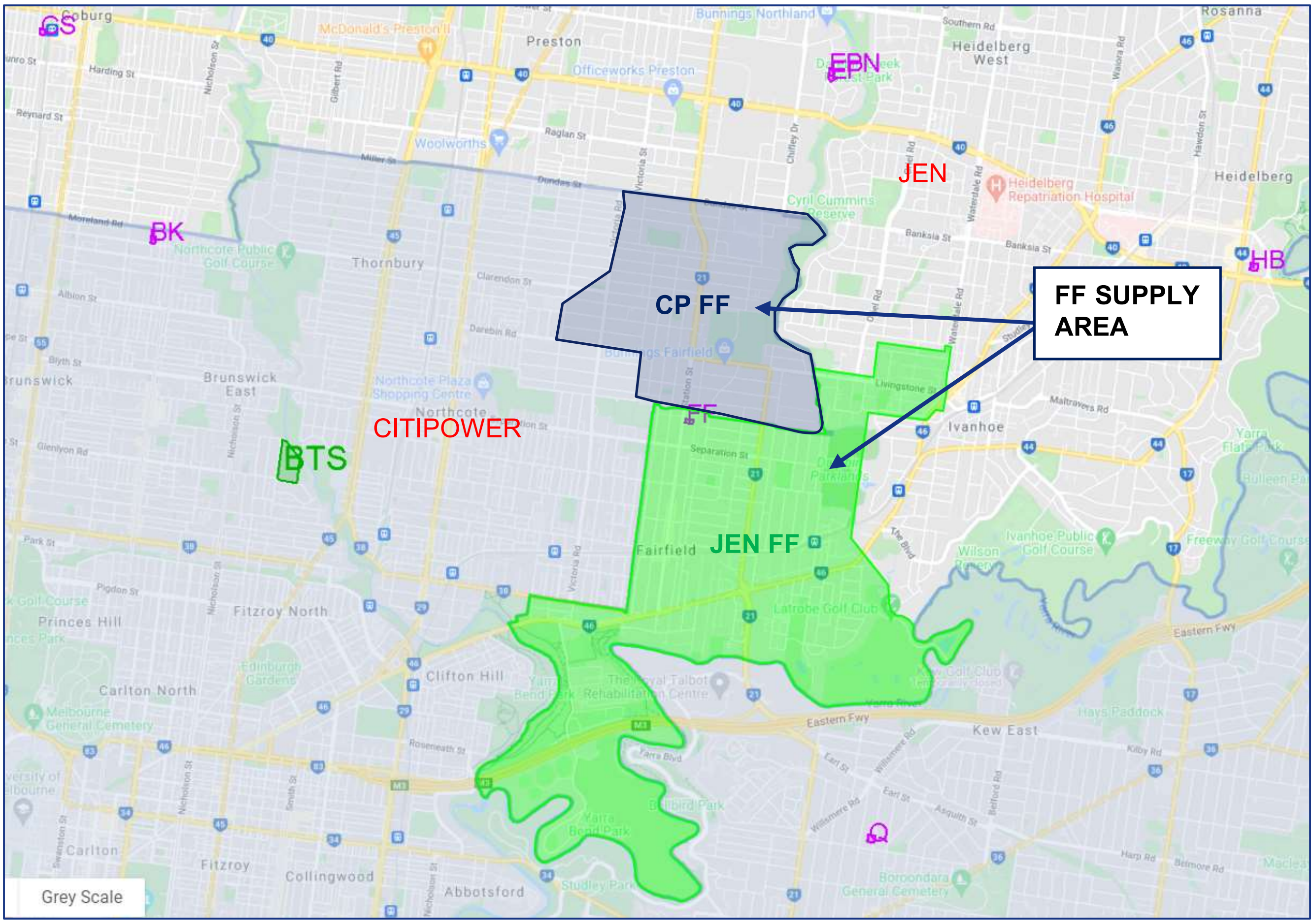
FF 6.6k V Feeders

JEN customers in Fairfield and Alphington are currently supplied by six 6.6 kV distribution feeders from FF. The zone substation also supplies six CitiPower 6.6 kV feeders into parts of Thornbury. The area is confined by 11 kV feeders from CitiPower's Northcote Zone Substation (**NC**) in the west and JEN's Heidelberg Zone Substation (**HB**) in the east.

The only electrical interconnection to the FF distribution network from other zone substations is with 6.6 kV feeders from JEN's East Preston Zone Substation (**EP**) in the north. With the ongoing conversion of the neighbouring EP, from 6.6 kV to 22 kV by 2024, the FF supply area will become an isolated 6.6 kV network.

Figure 2–3 shows the geographic supply area of FF and its surroundings, including the geographic split between JEN and CitiPower supply areas.

Figure 2–3: Supply areas of Fairfield (FF) Zone Substation - JEN and CitiPower



Customer numbers and customer contribution to peak demand

FF supplies approximately 10,285 customers, comprising 6,621 JEN customers and 3,664 CitiPower customers. The zone substation is mainly supplying residential customers.

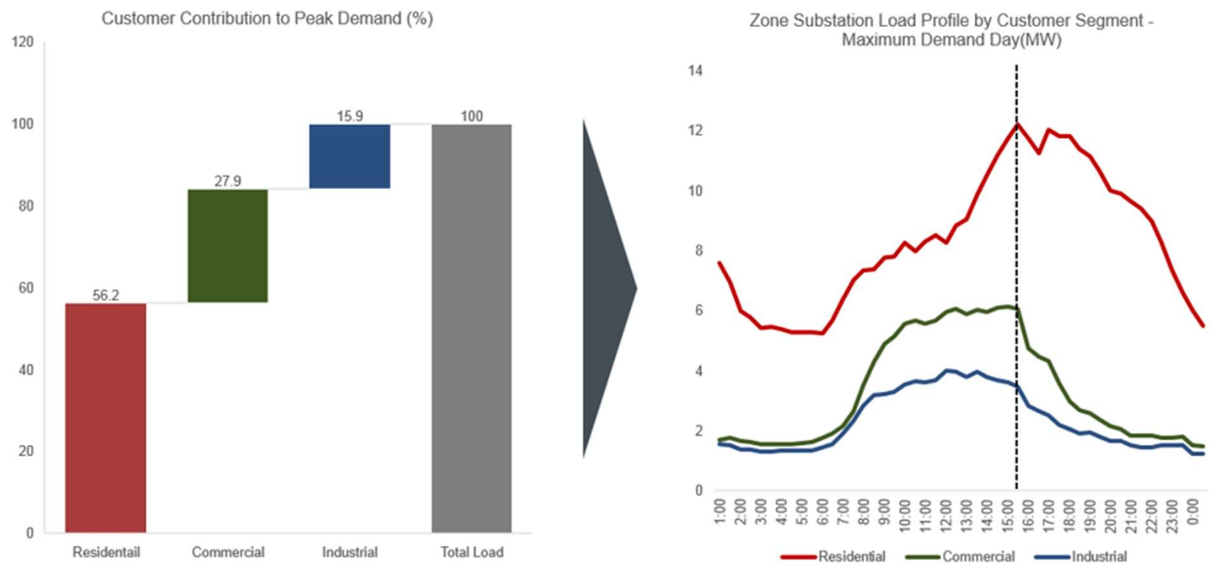
Table 2–1 shows the customer segments supplied by FF.

Table 2–1: Customer Numbers supplied by FF

Customer Segment	Number	Percent
Residential	9,686	94%
Commercial	584	6%
Industrial	15	<1%
FF TOTAL	**10,285**	**100%**

Figure 2–4 below shows the customer contribution to peak demand at FF.

Figure 2–4: FF Customer contribution to Peak Demand – JEN Customers



JEN's commercial and industrial customers in the area account for approximately 10 MW of load during peak demand (44% of total peak demand).

3. Description of identified need

Electricity supply to FF is provided by three 22 kV subtransmission lines (BTS-FF 181, BTS-FF 184 and BTS-FF 188) supplied from AusNet Services' Brunswick Terminal Station (**BTS**) to form the BTS-FF subtransmission loop. Table 3-1 shows the current rating of the subtransmission lines supplying FF.

Table 3-1: BTS-FF Subtransmission line rating

	Summer (MVA)	Winter (MVA)
BTS-FF 181	11.4	13.0
BTS-FF 188	13.1	13.7
BTS-FF 184	13.1	13.7

The existing BTS-FF 22 kV subtransmission lines are forecast to be overloaded due to an increase in demand around the Fairfield supply area. Maximum demand at FF is expected to grow on average at 4.3% per annum over the next five years. The expected increase in demand is mainly driven by the current and proposed residential and commercial developments at the former Amcor Paper Fairfield site, known as YarraBend. New developments at the YarraBend site plan to include over 1,900 new residential dwellings (mixture of apartments and townhouses), together with major multi-level commercial and retail facilities.

Although there is enough transformation capacity at FF to supply this additional demand, the existing 22 kV subtransmission lines supplying FF from BTS are currently fully utilised and will not have sufficient capacity to meet the increasing demand associated with the new development at YarraBend. Based on the current forecast, the existing subtransmission loop is exposed to the following risks:

- loss of any one of the 22 kV subtransmission lines (N-1) from BTS will lead to an overload on the remaining two lines, well above their thermal capacity rating; and
- simultaneous loss of two 22 kV subtransmission lines (N-2) under the following single contingency events will lead to an overload on the remaining single line, well above the thermal capacity rating:
  - outage of 1,760 m long BTS-FF 184 and BTS-FF 188 double circuit pole line; or
  - outage of 700 m long BTS-FF 181 and BTS-FF 184 double circuit pole line.

Major risks associated with operating network assets above their thermal capacity rating are:

- risk of breaching statutory clearances on overhead conductors on the remaining in-service line(s);
- increased risk of failure of equipment (e.g., cables, joints, etc.) on the remaining in-service line(s); and
- inability to restore all lost supplies in the event of a subtransmission line outage until load has decreased.

Table 3-2 and Table 3-3 show the forecast utilisation of the 22 kV lines under N and N-1 conditions until 2030.

Table 3-2: Subtransmission line 10% PoE maximum demand forecast (MVA) under system normal (N)

Line	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BTS-FF 181	6.3	6.4	6.7	7.0	7.4	7.7	7.9	8.1	8.1	8.1
BTS-FF 188	9.9	10.1	10.5	11.1	11.7	12.2	12.4	12.7	12.8	12.8
BTS-FF 184	10.2	10.4	10.8	11.4	12.0	12.5	12.7	13.0	13.1	13.1

Table 3-3: Subtransmission line 10% PoE maximum demand forecast (MVA) under outage condition (N-1)

Line	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BTS-FF 181	10.4	10.6	11.1	11.7	12.3	12.8	13.1	13.4	13.5	13.5
BTS-FF 188	16.3	16.7	17.4	18.4	19.4	20.2	20.6	21.2	21.3	21.3
BTS-FF 184	16.5	16.9	17.6	18.6	19.6	20.5	20.8	21.4	21.5	21.5

Notes:

1. The loading beyond the line rating are red highlighted numbers, which shows that the lines will be overloaded.
2. The maximum demand forecast under outage condition (N-1) are calculated as follows:
   a) The BTS-FF 181 line loading is calculated in two different scenarios i.e., one with BTS-FF 184 out of service and another with BTS-FF 188 line out of service.
   b) The values tabulated for BTS-FF 181 line are the highest of these two scenarios.
   c) A similar calculation method follows for BTS-FF 184 and BTS-FF 188 lines.

As highlighted above, the subtransmission lines supplying FF are already operating above 100% of their thermal rating. Lines 184 and 188 are already operating above 120% of their thermal rating under single contingency conditions during the summer peak period. Due to conductor thermal inertia characteristics, loading the subtransmission lines above 120% of their normal rating does not allow network controllers sufficient time to reduce load to within line normal ratings, and can therefore result in irreversible conductor damage and cascade tripping of network elements. In addition, there will be increased risk of breaching statutory clearances (green book[9]) on bare overhead conductors by operating assets above rating. The substandard clearance could lead to accidents (such as vehicles contacting overhead conductors and sagged 22 kV lines being in contact with subsidiary 11 kV and 6.6 kV circuits).

Table 3–4: Annual forecast supply risk (50% PoE and 10% PoE Weighted)

Year	Load-at-risk (MVA) under system normal condition (N)	Load-at-risk (MVA) under contingency condition (N-1)	Energy at Risk (MWh) Annual	Hours at Risk (h)	Expected Unserved Energy (EUE) (MWh)	Cost of Expected Unserved Energy ($k)[10]
2021	0.0	6.0	44	33	0.5	15
2022	0.0	6.8	59	33	0.8	26
2023	0.0	8.2	91	45	4.9	167
2024	0.0	10.3	156	52	10.1	344
2025	0.0	12.5	194	70	24.4	832
2026	0.0	14.5	239	83	40.2	1,374
2027	0.0	15.3	281	106	56.7	1,938
2028	0.0	16.7	336	114	78.3	2,676
2029	0.0	16.9	355	114	79.7	2,725
2030	0.0	16.9	383	141	79.7	2,725

The load-at-risk under a N-1 single contingency condition in 2022 could impact supply to up to 2,600 customers. Due to the double circuit line construction for the subtransmission lines as shown in Figure 2–1, there is a likely

9 http://www.vesi.com.au/index.php/the-green-book

10 Real June 2021 dollars.

chance of simultaneously losing two 22 kV subtransmission lines (N-2) during a single contingency event such as a vehicle accidentally running into a pole. This could potentially lead to an outage of a significant portion of FF due to subsequent overload on the remaining in-service line. This risk currently affects up to 6,200 customers supplied from FF. Given the lower probability of N-2 events, only the N and N-1 risks have been quantified for this RIT-D in Table 3–4. However, in this instance the N-2 risk from a single credible event is significant enough to bring forward the preferred network investment by one year.

4. Assessment methodology and assumptions

This section provides a summary of the planning methodology applied in assessing the impact of network limitations, and in identifying and assessing the market benefits of credible options. It also outlines the assumptions applied in the initial assessment of credible options.

4.1 Probabilistic planning approach

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

To achieve this objective, Jemena applies a probabilistic planning method that considers the likelihood and severity of critical network outages. The method combines the expected impact of network outages on supply delivery with the value that customers place on their supply reliability, and compares this with the augmentation costs required to reduce the likelihood and/or impact of these supply outages.

To ensure the maximisation of net economic benefit, an augmentation will only be undertaken if the benefits, which are typically driven by a reduction in the cost of expected unserved energy (**EUE**), outweigh the cost of the proposed augmentation resulting in that reduction in EUE. Since an augmentation will not always be economically feasible, this planning methodology involves an inherent risk that under some possible but rare events—such as the occurrence of a network outage coincident with peak demand periods—there may be insufficient network capacity to meet all demand.

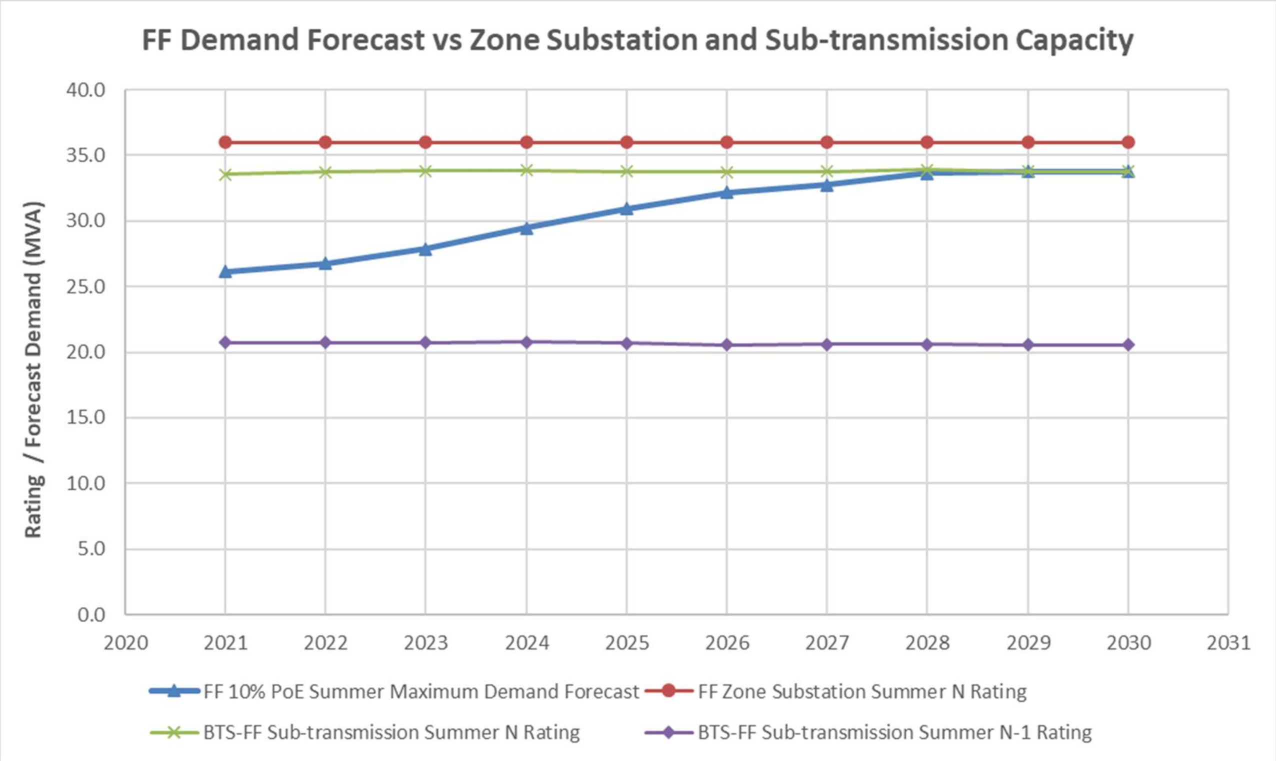
4.2 Demand forecasts

The electricity demand forecasts used in the preparation of this report are JEN's 2020 maximum demand forecasts. Our central forecast for demand for FF zone substation is an average increase of 4.3% over the next five-year period. JEN will provide details of the sensitivity analysis to examine the effects of different load growth forecasts in the DPAR, which will be published after we have considered submissions on this Non-Network Options Report.[11]

Figure 4–1 shows the forecast summer peak demand for FF under 10% POE conditions relative to the zone substation and subtransmission ratings.

[11] Under clause 5.17.4(h) of the National Electricity Rules, we must provide at least 3 months for interested parties to lodge submissions on the Non-Network Options Report. Clause 5.17.4(i) requires us to publish a DPAR within 12 months of the end of the consultation period on the Non-Network Options Report.

Figure 4–1: Summer maximum demand forecast vs capacity for FF and its subtransmission lines



4.3 Value of customer reliability

The cost of EUE is calculated using the Value of Customer Reliability (**VCR**). This is an estimate of how much value electricity consumers place on a reliable electricity supply.

In assessing the credible options to alleviate the impact of constraints on its network, JEN has applied VCR values based on the AER's Values of Customer Reliability Review published in December 2019.[12]

Applying the sector values developed by the AER to FF zone substation energy composition data, JEN has applied a composite VCR of $34.18/kWh for 2021 in preparing this Non-Network Options Report.

The composite VCR for FF has been derived in Table 4-1.

Table 4–1: VCR for FF

Sector	AER VCR ($/kWh)	Annual Energy consumption (%)	Energy Consumption weighted VCR ($/kWh)
Residential (climate zone 6 CBD and suburban)	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 2021)			**34.18**

12 AER, Values of Customer Reliability Final Report on VCR values, December 2019.

4.4 Discount rate

A nominal discount rate of 5.17% has been applied in undertaking the initial assessment of the network options presented in this report. However, further consideration of the discount rate and sensitivity analysis will be provided in the DPAR.

4.5 Cost estimates

The capital cost estimates for all network options are indicative costs only. They have been developed with consideration given to recent similar augmentation projects and typical unit costs based on industry experience. The capital cost estimates used for the purpose of this Non-Network Options Report are expressed in real 2021 dollars.

At this early stage of the assessment process, we have not developed detailed operating expenditure estimates for each credible network option. However, indicative total annualised cost estimates for the credible network options are provided based on discount rate of 5.17%, including an assumed 1% of capital cost per annum for additional operation and maintenance (**O&M**). Cost estimates will be further refined in the course of JEN preparing the DPAR.

5. Summary of potential credible options

This section provides a summary of potential credible network and non-network options that JEN believes would address the identified need described in Section 3. The analysis of options presented in this report is indicative only and is subject to change when further detailed information is considered in the preparation of the DPAR.

The following options to alleviate the emerging constraints were investigated:

- Option 1: Do nothing (base case);
- Option 2: Reinforce supply to FF and surrounding areas from the adjacent Heidelberg (**HB**) substation. This will assist in reducing the load-at-risk on the BTS-FF lines;
- Option 3: Install a capacitor bank at FF. This option will marginally reduce the load-at-risk on the BTS-FF lines by reducing network losses and improving the power factor;
- Option 4: Augment the BTS-FF subtransmission loop by installing a new fourth line from BTS to FF. This will assist in reducing the load-at-risk on the BTS-FF lines; and
- Option 5: Non-network options including embedded generation and demand management.

5.1 Option 1: Do Nothing (base case)

The “Do Nothing” option presents the forecast expected energy-at-risk assuming none of the identified network augmentation options are implemented. It is used as a reference or the “base case”, against which all of the credible options are compared. As highlighted above, the risks associated with the “Do Nothing” option are:

- increased risk of breaching statutory clearances (green book) on bare overhead conductors;
- increased risk of failure of equipment (e.g., cables, joints, etc.) when equipment is pushed to operate well above its design limits;
- inability to restore all lost supplies in the event of loss of an FF subtransmission line during peak demand periods;
- deterioration of supply reliability due to capacity shortfall; and
- intangible costs to JEN arising from negative publicity generated due to longer than expected supply restoration times.

Table 3–4 above summarises the annual value of the EUE for the BTS-FF subtransmission lines for the base case over the next ten years (2021 to 2030). As highlighted in Table 3–4, the cost of EUE increases from $15,000 in 2021 to $2,725,000 in 2030.

5.2 Option 2: Reinforce supply to FF from HB

This option looks at supplying all of the YarraBend Development from HB by running three new 11 kV feeders from HB. The 66 kV subtransmission loop supplying HB is shared between CitiPower and Jemena and is already operating well above its rating under single contingency conditions. Hence, the 66 kV loop needs to be upgraded before adding major new load to HB from YarraBend.

The existing HB 66 kV subtransmission loop is fully rated. Therefore, to increase the capacity on the loop, a third 66 kV line needs to be installed and supplied from Templestowe Terminal Station (**TSTS**), noting that Jemena does not have any easement available to run a new 66 kV line from TSTS to HB. Given that the Templestowe and Heidelberg areas are densely populated and outside the JEN distribution network, it is assumed that undergrounding the subtransmission line might be the only acceptable solution.

The proposed scope of works include:

- installing 1 x 66 kV feeder exit circuit breaker at TSTS;
- installing 1 x 66 kV bus-tie circuit breaker and 1 x 66 kV line circuit breakers at HB[13]; and
- installing approximately 9.5 km of new underground 3 x 1c 1200 mm^2 Al XLPE 66 kV cable in conduit from TSTS to HB.

The total cost to run a new subtransmission line from TSTS to HB is estimated to be $27.59 million in real 2021 dollars. The annualised cost for this option including operational and maintenance costs is estimated to be $1.70 million. On completion of the proposed project, there will be no load-at-risk on the HB subtransmission lines under N and N-1 conditions for the next ten years. This option addresses the network need.

5.3 Option 3: Install a capacitor bank at FF

Installing capacitor banks at zone substations can release existing capacity in subtransmission circuits to accommodate increased demand. The power factor forecast for FF is expected to fall to 0.97 within the next 5 years. With a peak summer 10% PoE demand of 33.8 MVA by summer 2030, FF will have a net reactive power demand of 8.0 MVAr.[14]

The high-level scope of this option includes the following works:

- establish a new 6.6 kV 8.0 MVAr capacitor bank at FF.

The capital cost of this option is estimated to be $400,000 in real 2021 dollars. The annualised cost for this option including operational and maintenance costs is estimated to be $25,000.

This option will reduce the load-at-risk by up to 1.0 MVA.[15] Given the small reduction in load-at-risk, this option does not address the need, which sees the load-at-risk under the base case rise from 6.0 MVA to 16.9 MVA over the forecast period. The option only addresses 6% of the load-at-risk.[16]

5.4 Option 4: Augment BTS-FF 22 kV loop

This option involves establishing a fourth 22 kV line from BTS to FF to augment the BTS-FF 22 kV subtransmission loop by installing a new 22 kV underground cable. Given that FF is located in a rather densely populated area, it is assumed that the new BTS-FF 22 kV line will have to be fully undergrounded. BTS does not have any spare 22 kV circuit breakers and the 22 kV bus at BTS will therefore have to be extended.

The existing subtransmission lines have sections of the route running two 22 kV circuits on the same pole line (double circuit pole). A single contingency event on this section could take both 22 kV lines out of service, which could result in a loss of supply to FF. This proposed option to have four 22 kV lines from BTS to FF will eliminate this risk.

The proposed scope of works include:

- extend existing BTS 22 kV Bus-1 and Bus-3 and install a new CB at Bus-1 and a new CB at Bus-3 to have double switched arrangement at BTS terminal station to establish a new subtransmission feeder exit;
- install 1 x 22 kV circuit breaker within the FF 22 kV switch-room;

13 It is yet to be confirmed whether there is physical space available at HB for a new CB.

14 $33.8 \times \text{sqrt}(1 - 0.97^2) = 8.0$ MVAr.

15 $33.8 \times (1 - 0.97) = 1.0$ MVA.

16 $1.0 / 16.9 = 6\%$.

- supply and install approximately 4.1 km of new 2 x 3c 300 mm^2 Al XLPE underground cable from BTS feeder CB to the new 22 kV pole within FF; and
- make the connection to FF between CB A and a new CB as shown below in Figure 5–1.

Figure 5–1: FF single line diagram after connection of fourth 22 kV subtransmission line

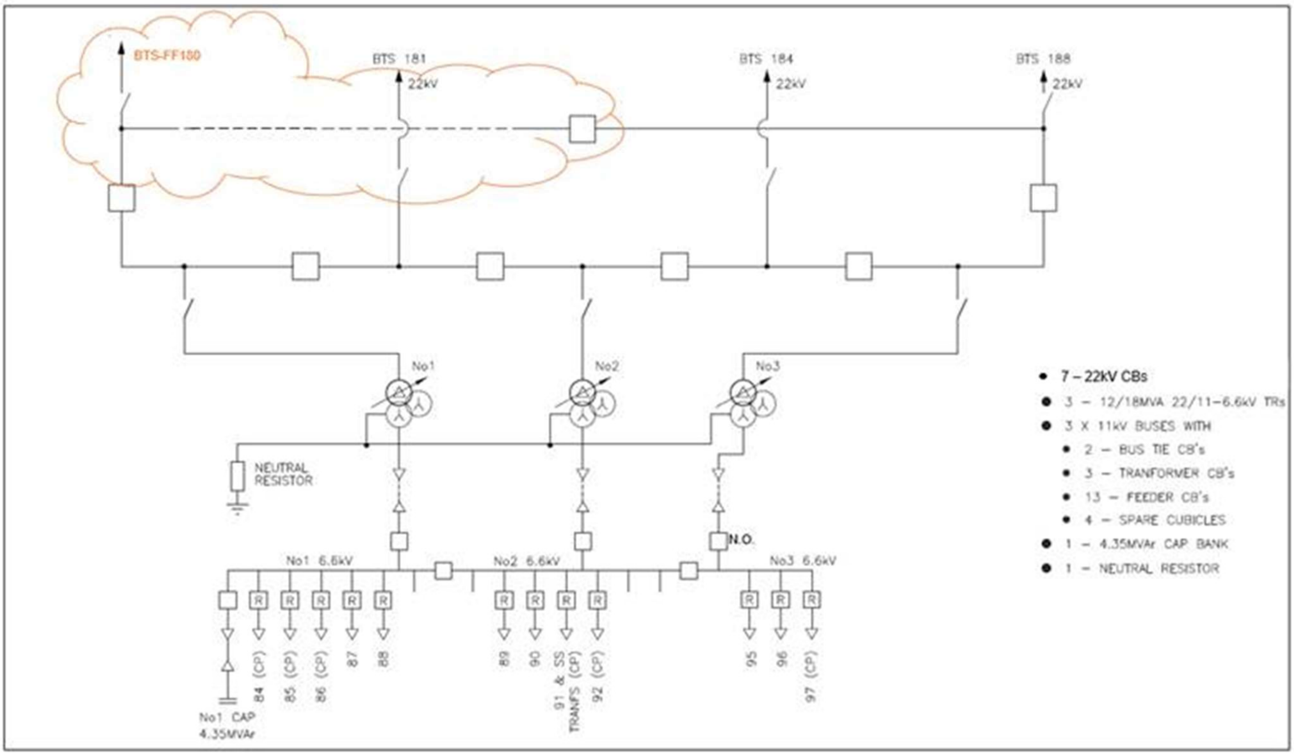


Table 5-1 below shows the new rating of the subtransmission lines on completion of this scope.

Table 5-1: Subtransmission line rating (MVA) on completion of Option 4

Circuit	Summer	Winter
BTS-FF 181	11.4	13.0
BTS-FF 188	13.1	13.7
BTS-FF 184	13.1	13.7
BTS-FF 180 (New Circuit)	30.5	30.5

The total cost to run a new subtransmission line from BTS to FF is estimated to be $6.78 million in real 2021 dollars. The annualised cost for this option including operational and maintenance costs is estimated to be $418,000. On completion of the proposed project, there will be no load-at-risk on the FF subtransmission lines under N and N-1 conditions for the next ten years. This option addresses the network need.

5.5 Option 5: Non-network options

This option is to contract network support services in the FF supply area (covering Fairfield, Alphington and eastern Thornbury) to address the identified network supply risks.

The network support services could include non-network solutions such as:

- a grid-scale battery (6.6 kV or LV connections);
- demand management (interruptible load, controllable load or behavioural demand response); and/or
- embedded generation (such as solar PV and battery combination, or any other dispatchable generator).

The potential non-network solution may also be combined with a suitable network augmentation option to delay or reduce the scope of works of credible network options to maximise the net market benefits. At the time of preparing this Non-Network Options Report, there are no known proponents of non-network options in the FF supply area. Non-network proponents are encouraged to express their interest to JEN as per Section 8.

6. Preferred network option

Table 6-1 presents a summary of the overall economic analysis of credible network options considered in this report, based on discount rate of 5.17% and 25-year regulatory asset life.

Table 6-1 Present Value of Net Economic Benefits of each option (real million, $2021)

Option	Option name	Present Value Costs[17]	Present Value Benefits[18]	NPV of Net Market Benefits	Ranking
1	Do nothing (base case)	0	0	0	4
2	Reinforce supply from HB	24.07	25.39	1.32	2
3	Install a capacitor bank at FF	0.46	1.57	1.11	3
4	Augment BTS-FF 22 kV loop	6.58	27.14	20.56	1

Option 4, installing a new fourth 22 kV line from BTS to FF, is the option that maximises the net market benefits compared with all other network options considered, and is therefore the preferred credible network option. The optimum timing for Option 4 is to have the solution commissioned by the summer of 2024-25. Optimum timing is brought forward by one year to the summer of 2023-24 when the risk of two circuits on a single pole line is considered.

[17] Capital and ongoing incremental O&M costs.

[18] Avoided cost of EUE. The present value cost of “Do Nothing” EUE is $27.6 million, real June 2021 dollars.

7. Technical characteristic of non-network options

This section sets out the technical characteristics of our needs.[19] This information is provided to enable proponents of non-network solutions to understand the identified need and to tailor their proposals accordingly. JEN wants to explore all potential non-network solutions with proponents to deliver the most economical solution to our customers.

We recognise that proponents may require additional specific information to develop their proposals. Accordingly, we encourage proponents to contact us as early as possible, to ensure that we can provide all the specific information that a proponent may require.

Further details on how to contact us are set out below in Section 8.1.

7.1 Size and location of load reduction or additional supply

Table 7–1 below outlines the minimum amount of load reduction or additional generation required in the FF supply area that would meet our identified need. While the table below defines our needs, it is conceivable that a non-network option may be preferred even if it does not fully address these requirements. The table should therefore be regarded as a guide. JEN will consider each option on its merits, having regard to its expected performance in terms of addressing our needs and the overall costs to our customers.

Table 7–1: Network support requirements for post-contingent risk mitigation

Year	Peak capacity required from non-network solutions (MVA)	Average duration required from non-network solutions (Hours)[20]	Average energy required from non-network solutions (MWh)	Potential value of network support payments per annum ($k)[21]
2022	0.8	33	15	10
2023	2.2	45	46	152
2024	4.3	52	112	329
2025	6.5	56	150	418
2026	8.5	56	195	418
2027	9.2	56	237	418
2028	10.6	56	291	418
2029	10.9	56	311	418
2030	10.9	56	339	418

The peak capacity is that capacity required above existing load-at-risk levels, needed to support a 10% PoE maximum demand. Only a post-contingent network support response is required from a non-network solution in this instance.

The average duration and energy required per annum is based on an expected summer using a weighted average of the 10% PoE and 50% PoE maximum demand forecasts, assuming a network contingency event has occurred. The potential value of the network support payment per annum is an upper limit on amount payable regardless of whether or not a network contingency event has occurred.

19 In accordance with Clause 5.17.4(e)(4) of the NER.

20 Capped to a 22 kV cable outage repair time of 7 days assuming risk window of 8 hours per day (i.e., 7 x 8 = 56 hours).

21 Capped to annualised cost of the preferred network option, real June 2021 dollars.

7.2 Potential deferred augmentation charge

As explained in Section 5.1, the base case would result in a significant amount of EUE. To be selected as the preferred solution, a non-network solution would need to maximise the net benefits compared with other available options, including the preferred network solution and competing non-network proposals. As already noted in Section 5.4, the augmentation cost for Option 4 is approximately $6.775 million. This equates to an annualised total charge of approximately $418,000 per annum inclusive of annual operational and maintenance costs.

On the basis that a non-network option delivers exactly the same performance as the preferred network solution, the deferred costs of $418,000 per annum represents the upper bound that would be available as an annualised network support payment.

As already indicated, it is conceivable that a non-network solution would offer a lower level of performance or an earlier delivery date compared with the network option. In such a case, the network support payments would need to be scaled back for the non-network solution to maximise the net benefit.

7.3 Timing of non-network option

The optimum commissioning date of our preferred network option is November 2023. This represents the latest operational date for an alternative non-network solution. A non-network option could be operational earlier than this date given there is already load-at-risk during an N-1 contingency condition.

7.4 Load profile and load duration for FF

The profiles of load supplied from FF during summer peak day and winter peak day are shown in Figure 7-1 below.

Figure 7-1: FF daily demand profile (peak days)

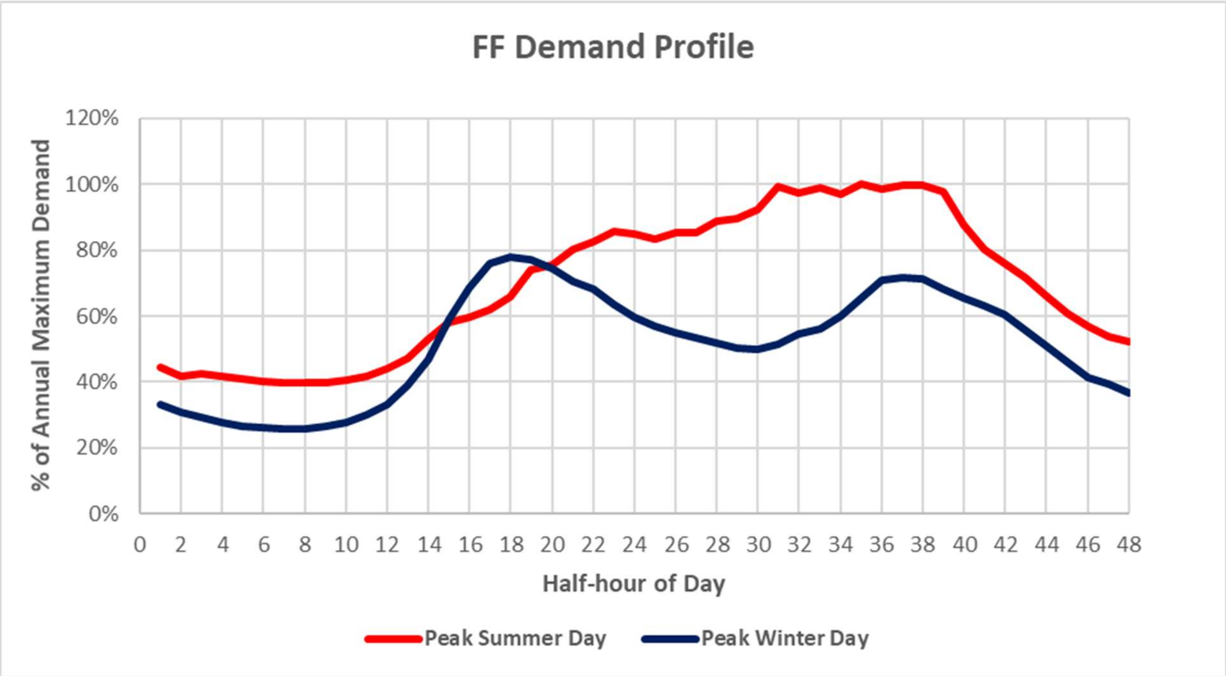
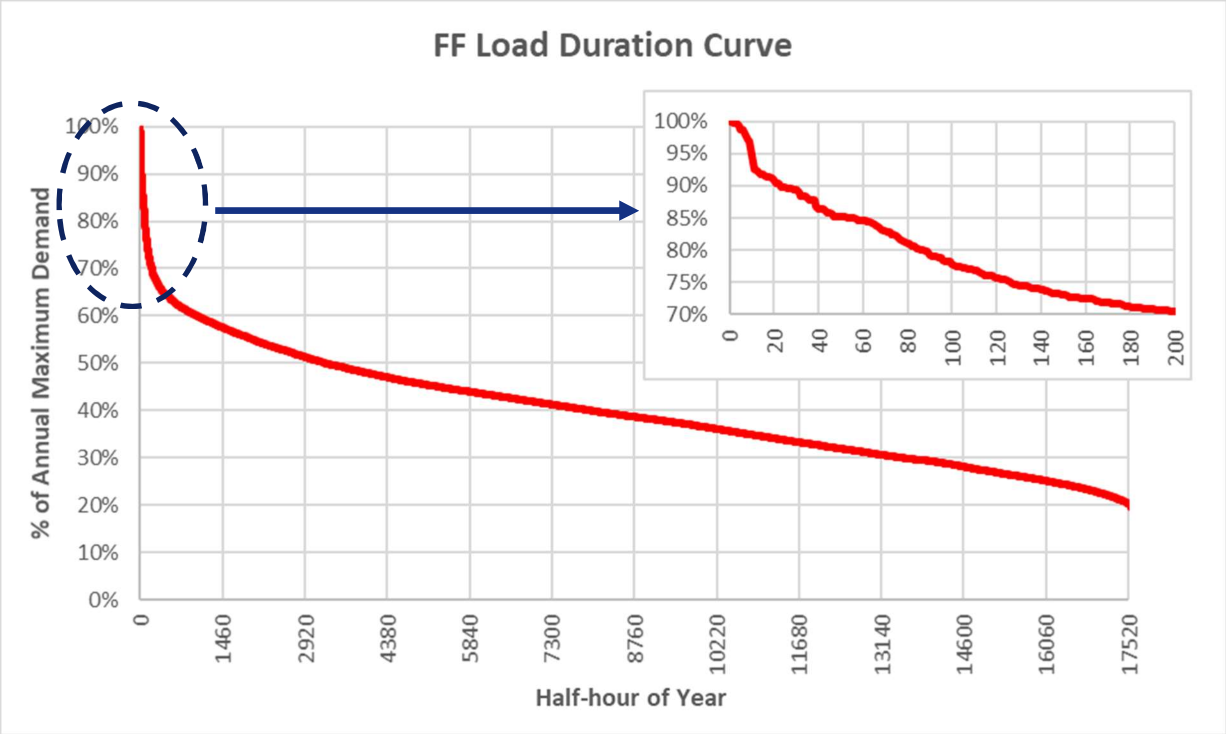


Figure 7-1 shows that peak loading on the station occurs during evening between 3:30 pm (half-hour 31) and 7:30pm (half-hour 39). Therefore, a non-network solution would be required to be available during this time (as a minimum) to reduce demand or increase local generation to avoid supply interruptions.

The load duration curve of FF is shown in Figure 7-2 below.

Figure 7-2: FF load duration curve



7.5 Power system security and reliability

To substitute for traditional 'poles and wires' augmentation, proposed non-network options must be capable of reliably meeting the electricity demand under a range of conditions. However, as already noted, a potentially viable non-network option would not necessarily be required to provide a level of reliability that is identical to that provided by the preferred network solution. Rather, the value of a non-network option will reflect the reduction in EUE that the option is capable of delivering relative to the network option. The preferred option is the one that maximises the present value of net benefits.

If the non-network option is a generator connected to JEN's distribution network, the generator will be required to comply with the standards set out in our Embedded Generation Guidelines[22]. The guidelines detail important requirements relating to:

- embedded generation access (connection) standards;
- embedded generation testing, commissioning and maintenance requirements; and
- operational constraints and standards.

Proponents of embedded generation solutions should familiarise themselves with these requirements. JEN would be pleased to discuss this opportunity further with non-network proponents. Specifically, we would be pleased to discuss any proposed cost/performance combination that proponents considered to be more cost effective than the preferred network solution.

7.6 Fault level contribution

The installation of an embedded generator may raise the fault (short-circuit) level of the network to which it is connected. It is important to ascertain that the resulting fault levels are not raised above the existing acceptable

[22] See: https://jemena.com.au/about/document-centre/electrcitiy/embedded-generation-guidelines.

rated fault levels for circuit breakers, conductors, any auxiliary plant and fittings including earth grid, Distribution Code or design limits. We may need to carry out system fault level studies to assess these matters.

Under Section 7.8 of the Victorian Electricity Distribution Code, an embedded generator is required to design and operate its embedded generating unit so that it does not cause fault levels in the distribution system to exceed the levels specified in Table 7–2 below. The existing fault levels at FF are specified in Table 7-3.

Table 7–2: Victorian Electricity Distribution Code fault levels

Voltage Level kV	System Fault Level MVA	Short Circuit Level kA
66	2500	21.9
22	500	13.1
11	350	18.4
6.6	250	21.9
<1	36	50.0

Table 7-3: FF zone substation fault levels

Voltage level (kV)	Fault levels (kA)	
	3 phase	1 phase to ground
22 kV	11.8	8.0
6.6 kV	15.4	2.2

8. Submissions from interested parties

8.1 Invitation for submissions

As highlighted above, we are interested in exploring all potential non-network solutions with proponents. We recognise that some proponents may require information in addition to that provided in this report. If you do need further information, please contact us as early as possible, to ensure that sufficient time is available to fully assess feasible network and non-network potential solutions. It should be noted that parts of the network exhibit volatile load growth, usually due to economic and demographic factors that are difficult to foresee and model. It is essential that alternatives to network solutions are presented by proponents in sufficient time to allow for their thorough evaluation, planning and implementation.

JEN seeks submissions from interested parties, including proponents of non-network solutions. 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 15 December 2021. All submissions will be published on Jemena's website. If you do not wish to have your submission published, please indicate this clearly.

8.2 Information from non-network proponents

To assist in the assessment of non-network solutions, proponents are invited to make a detailed submission. That submission should be informed by earlier discussions with us (arranged through the contact officer noted above) and should include the following details about the proposal:

1. proponent name and contact details;
2. overview of the extent to which the proposal addresses the identified need;
3. a technical description of the proposal, including:
    - name, address and contact details of the person responsible for non-network support;
    - type or technology proposed;
    - size and capacity for network support (MW/MVA/MWh);
    - proposed location(s);
    - frequency and duration;
    - proposed dispatch arrangement;
    - notice period required to enable the proposed solution;
    - proposed contract period;
    - electrical layout schematics;
    - availability and reliability performance details;
    - contribution to power system fault levels, load flows and stability studies (if applicable).
4. used cases from previous experience in implementing the proposed solution;

5. timeline to implement the proposed solution and its estimated lifespan;
6. breakdown of lifecycle costs in providing the network support, including:
   - capital cost
   - annual operating and maintenance cost
   - other applicable costs (e.g., dispatch fee, availability fee etc.)
   - salvage value and decommissioning costs.
7. proposed operational and contractual commitments including any special conditions to be included in a network support agreement; and
8. An evaluation of potential risks associated with the proposal, including a comparison with the risks associated with the preferred network augmentation option, and any actions that can be taken to mitigate these risks. This assessment should address the risk of not meeting the demand requirement and the compensation arrangements that would apply in such circumstances.

We will review each non-network option and we may seek further information from the non-network proponent to better understand the design of the proposed solution and its implications on the network and other network users.

9. Next steps

As outlined in Section 1, this report is being prepared under the RIT-D consultation procedures to help us and interested parties identify potential non-network options to address the identified need in the FF supply area.

Following our consideration of submissions on this Non-Network Options Report, we will proceed to prepare a DPAR. That report will present a detailed assessment of all options to address the identified need, plus a summary of and commentary on the submissions to this report. The DPAR will include the latest available information on demand forecasts, VCR estimates and project cost estimates.

We intend to publish the DPAR by 31 January 2022. Further consultation in accordance with the RIT-D process set out in the Rules will then proceed.