Jemena Electricity Networks (Vic) Ltd

Brunswick – Fairfield Subtransmission Loop Capacity Constraint

RIT-D Stage 2: Draft Project Assessment Report

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Executive summary

Jemena Electricity Networks (Vic) Ltd (**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.

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

This Draft Project Assessment Report (**DPAR**) forms the second stage of the Regulatory Investment Test for Distribution (**RIT-D**) consultation process. The DPAR presents the analysis results relating to JEN's supply reliability needs for the Fairfield and Alphington supply area, triggered by capacity overload limitations on the Fairfield Zone Substation (**FF**) subtransmission lines. The DPAR outlines how the supply reliability risks have been quantified, presents possible options for economically mitigating those risks, and identifies the preferred option to enable JEN to address the identified need at the least cost.

Identified need

JEN's Fairfield Zone Substation is located at the corner of Station St and McGregor St and supplies approximately 6,756 Jemena customers and 3,664 CitiPower customers (predominantly residential) at 6.6 kV in Fairfield and Alphington within the JEN supply area, and parts of Thornbury located in the CitiPower supply area. FF is supplied by three 22 kV subtransmission lines that originate from AusNet Services' Brunswick Terminal Station (**BTS**).

Electricity demand in the Fairfield and Alphington supply area is expected to grow on average at 4.2% 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 128% utilisation, which will require JEN to take customers off supply. Based on the current maximum demand forecast for a single contingency event during summer 2023-24, up to 3.7 MVA of load will be shed around the Fairfield and Alphington area to maintain the operation of the lines within their thermal safe loading limits. This will leave approximately 1,400 customers off supply during an outage on the subtransmission line. The subtransmission lines are also forecasted to exceed their thermal N rating from summer 2030-2031.

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 a single outage taking out two of the three 22 kV lines. In the event of this outage condition, this will leave approximately 5,900 customers off supply.

Table OV-8 shows the forecast utilisation for the most onerous subtransmission line 10% PoE summer and winter conditions.

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

2 JEN's acceptable loading on the subtransmission line under system normal to maintain supply reliability during single contingency (N-1) condition is 120% of the line rating.

Table OV-8: BTS- FF Subtransmission network forecast utilisation (10% PoE)

Condition	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Summer N	74%	79%	84%	87%	88%	90%	93%	97%	103%	108%
Summer N-1	120%	128%	137%	142%	145%	148%	152%	159%	168%	177%
Winter N	62%	67%	72%	74%	76%	76%	78%	82%	86%	90%
Winter N-1	101%	109%	116%	120%	122%	124%	127%	133%	141%	147%

RIT-D process

DNSPs are required to undertake a RIT-D process to identify investment options that best address an identified need on the network. 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]. As part of the RIT-D process, DNSPs must also consider non-network options when assessing credible options to address the identified need.

Options considered

Jemena has identified below, potential credible network options to alleviate the current and emerging capacity overload limitations on the BTS-FF 22 kV subtransmission lines:

- **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**: Augment the BTS-FF 22 kV subtransmission loop by installing a new fourth line from BTS to FF using a single cable. This will assist in reducing the load-at-risk and losses on the BTS-FF lines.
- **Option 4**: Augment the BTS-FF 22 kV subtransmission loop by installing a new fourth line from BTS to FF using twin cables. This will assist in reducing the load-at-risk and losses on the BTS-FF lines; and
- **Option 5**: Combine the existing BTS-FF 184 and BTS-FF 188 lines and augment the BTS-FF 22 kV subtransmission loop by installing a new third line from BTS to FF using twin cables. This will assist in reducing the load-at-risk and losses on the BTS-FF lines.

As part of the RIT-D process, JEN considered the credibility of potential non-network options as alternatives to the network options listed above. A Non-Network Options Report, published on JEN’s website on 22 September 2021, was prepared to establish whether a non-network solution is potentially available to address the identified need. The Non-Network Options Report was predicated on the need for a non-network option to reduce the expected unserved energy risk that would otherwise have been addressed by a network solution. From the consultation on the Non-Network Options Report that closed on 15 December 2021, JEN did not receive any submissions that identified a viable non-network alternative solution.

Proposed preferred option

The RIT-D options analysis concludes that:

- Option 5 to combine the existing BTS-FF 184 and BTS-FF 188 lines and augment the BTS-FF 22 kV subtransmission loop with a new third line from BTS to FF using twin cables for $10.58 million[4] is the preferred network option because it addresses the identified need and maximises the present value of net market benefits compared with all the other options;

[3] 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.

[4] Real 2023 dollars, capital cost.

- The optimum timing of the investment is to have the preferred network option in service by 1 November 2024 to align with the start of the 2024-25 summer peak demand period. However, given the lead time for project construction and commissioning, the completion of the preferred network option is by 1 November 2025 ; and
- There are no identified credible non-network options or combinations of non-network options with network options that could be used to economically defer the need for the preferred network option.

The preferred option (Option 5) was tested under a range of sensitivities including variations in costs, Value of Customer Reliability (**VCR**) and other base assumptions. In each case, Option 5 was confirmed to provide positive economic benefits and is the highest-ranked option.

JEN intends to proceed with the preferred network option to address the identified need. The preferred option has a net market benefit of $57.68 million (real, 2023) compared with the "Do Nothing" option as shown in Table ES-1.

Table ES–1: Summary of the present value analysis for the preferred option (real, million $2023)

Present Value of Costs	"Do Nothing" Option 1	"Preferred" Option 5
Network capital investment	-	(10.06)
Additional opex investment (O&M)	-	(1.37)
Expected unserved energy (EUE)	(59.93)	(0.00)
Electricity network energy losses	(1.12)	(0.67)
Net Present Value of Benefits	**n/a**	**48.95**

Submission and next steps

JEN invites written submissions on this report from Registered Participants, interested parties, AEMO and non-network providers. If no submissions are received on this report, this DPAR will be the final stage in the RIT-D Process and JEN will include the final decision in the 2023 Distribution Annual Planning Report (**DAPR**). If submissions are received on this report, JEN will publish a Final Project Assessment Report (**FPAR**).

All submissions and enquiries should be directed to:

Email: PlanningRequest@jemena.com.au
Phone: (03) 9173 7000

Submissions should be lodged on or before 20 October 2023. All submissions will be published on JEN's website. Please indicate if you do not wish to have your submission (or parts of the submission) published.

After considering any submissions on this DPAR, JEN will proceed to prepare a FPAR. That report will include a summary of, and commentary on, any submissions to this report, and present the final preferred solution to address the identified need. Publishing the FPAR will be the final stage in the RIT-D process.

JEN intends to publish the FPAR by 30 October 2023. If no submissions are received on this report, JEN will discharge its obligation to publish the FPAR and instead include the final decision in the 2023 DAPR[5].

[5] As per NER clause 5.17.4(s).

Glossary

Augmentation	An investment that increases network capability to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Capacity	Refers to the network's ability to transfer electricity to customers.
Contingency	Refers to a network asset fault or failure of part of the network.
Energy-at-risk	The total energy-at-risk of not being supplied if a contingency occurs.
Expected Unserved Energy (EUE)	Refers to an estimate of the probability-weighted, long-term average annual energy-at-risk, considering the probability of a contingency condition. The EUE is transformed into an economic value, suitable for cost-benefit analysis, by multiplying it with the Value of Customer Reliability (VCR), which reflects the economic cost per unit of unserved energy.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 360,000 customers via an 11,000-kilometre distribution system covering north-west greater Melbourne.
Limitation	Refers to a constraint on a network asset's ability to transfer power.
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.
Network	Refers to the collection of physical assets required to transfer electricity to customers.
Non-network	Any measure to reduce peak demand and/or increase supply.
Probability of Exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
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 in the National Electricity Market (NEM).
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
Value of Customer Reliability (VCR)	Represents the financial value customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
Zone substation	Refers to the location of transformers, ancillary equipment and other supporting infrastructure that facilitate the electrical supply to a particular zone in the Jemena Electricity Network (JEN).

Abbreviations

1C	1-core
3C	3-core
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Al	Aluminium
BTS	Brunswick Terminal Station (owned by AusNet Services)
CB	Circuit Breaker
DAPR	Distribution Annual Planning Report
DNSP	Distribution Network Service Provider
DPAR	Draft Project Assessment Report (this report)
EP	East Preston Zone Substation
EUE	Expected Unserved Energy
FF	Fairfield Zone Substation
FPAR	Final Project Assessment Report
HB	Heidelberg Zone Substation
HV	High Voltage
JEN	Jemena Electricity Network
kV	Kilo-Volts
LV	Low Voltage
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
NC	Northcote Zone Substation (owned by CitiPower)
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value (of Benefits)
NSP	Network Service Provider
O&M	Operations and Maintenance
POE	Probability of Exceedance
PV	Present Value (of Costs, or Benefits)
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

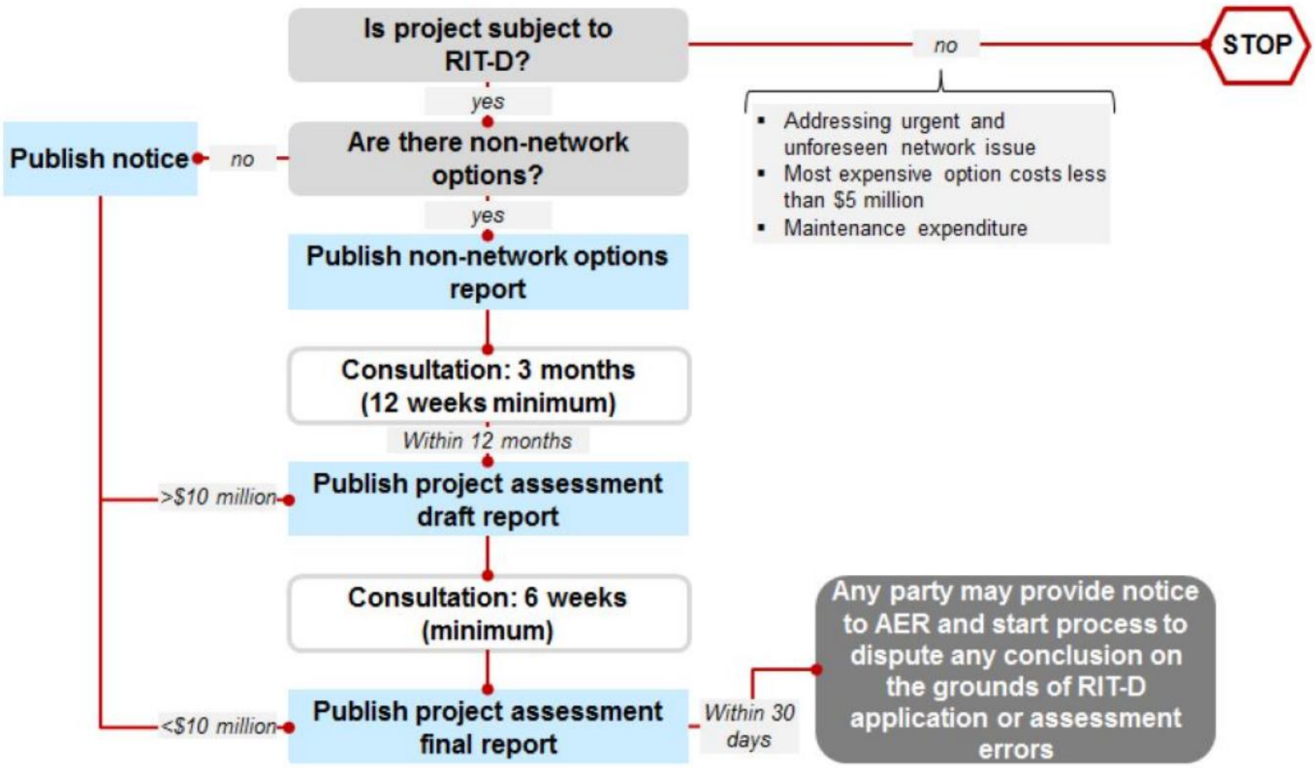
This section outlines the purpose and process of the RIT-D and the structure of this DPAR.

1.1 RIT-D purpose and process

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 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[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 illustrated 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 DPAR. This report undertakes an economic evaluation of credible network and non-network options against the base case to identify the preferred option. This document is JEN's DPAR for the needs associated with the Fairfield and Alphington supply area and, in particular, the reliability of supply needs triggered by capacity overload limitations on the BTS-FF 22 kV subtransmission loop.

In accordance with the requirements of clause 5.17 of the NER, this report contains:

- a description of the identified need for the investment;

[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 (1 August 2022) – Figure 1.

- the assumptions used in identifying the identified need;
- a summary of, and commentary on, the submissions (if any) on the non-network options report;
- a description of each credible option assessed;
- a quantification of each applicable market benefit for each credible option;
- a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;
- a detailed description of the method used in quantifying each class of cost and market benefit;
- reasons classes of market benefits or costs do not apply to a credible option;
- the results of net present value analysis of each credible option and accompanying explanatory statements regarding the results;
- the identification and details of the proposed preferred option; and
- contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.

1.2 Structure of this report

This DPAR is the second stage of the RIT-D consultation process to explore credible options for JEN to maintain supply reliability to the Fairfield and Alphington supply area. It follows on from JEN's Non-Network Options Report consultation and considers network, non-network and hybrid options based on that report.

The contents of this DPAR are set out as follows:

- Section 2 details the Fairfield and Alphington supply area;
- Section 3 articulates the identified need in relation to the Fairfield and Alphington supply area;
- Section 4 sets out the credible non-network options assessed to address the identified need;
- Section 5 sets out the credible network options assessed to address the identified need;
- Section 6 summarises the method used to quantify market benefits;
- Section 7 presents the net present value assessment results for the credible options assessed; and
- Section 8 details the technical characteristics of the proposed preferred credible option and the next steps.

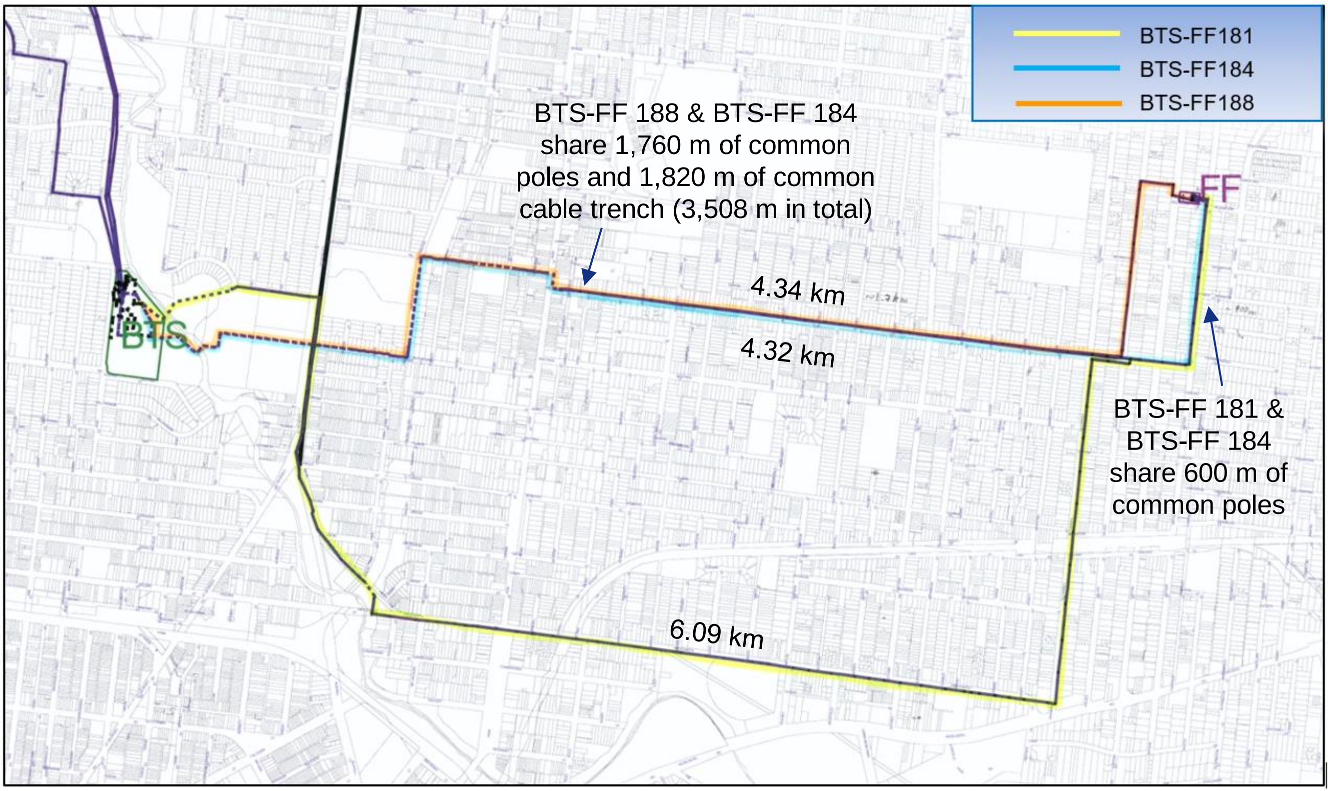
2. Background

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

2.1 Fairfield and Alphington supply area

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 BTS-FF subtransmission lines are sharing the same pole line or cable trench with another BTS-FF line for parts of the route, increasing the likelihood of a 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



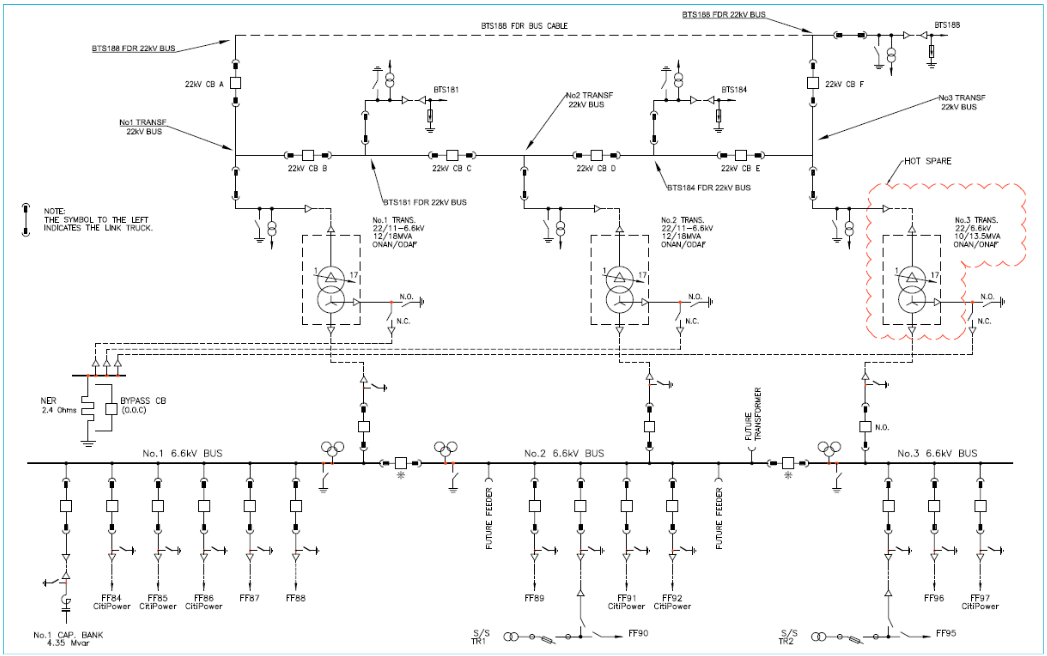
FF currently has two 22/11-6.6 kV 12/18 MVA dual winding transformers (replaced in 2020) and one 22/6.6 kV 10/13.5 MVA single winding transformer (as a cold-spare[8]), a 2.4 Ω neutral earthing resistor and twelve 6.6 kV feeder circuit breakers.

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 in parts of Thornbury. The remaining six 6.6 kV feeders supply approximately 6,756 customers in JEN's distribution area.

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

8 Due to condition and noise issues with this transformer, there are plans to replace this transformer within the next 5 years.

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

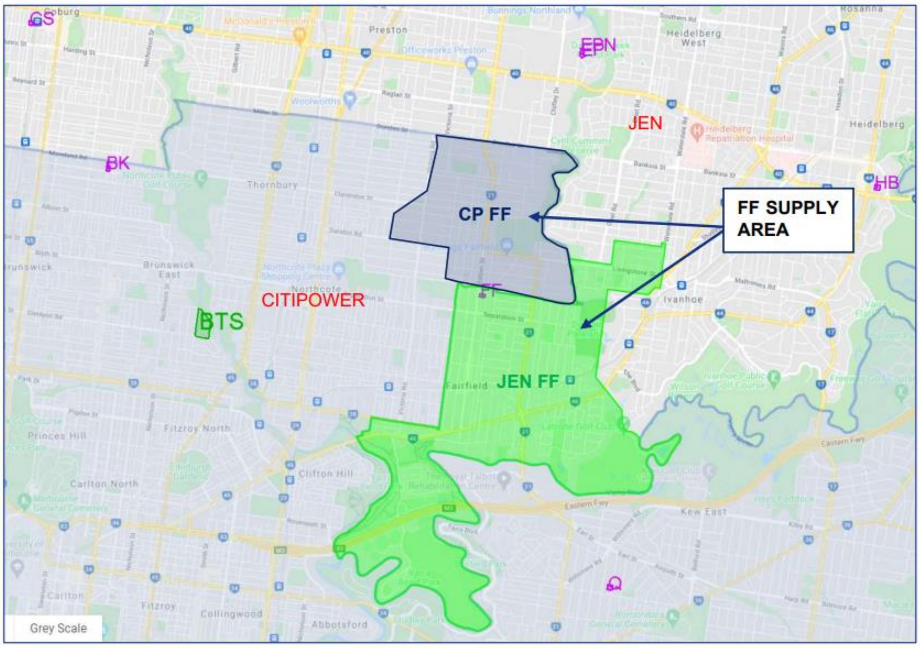


This 6.6 kV supply area is confined by 11 kV feeders from CitiPower's Northcote Zone Substation (**NC**) in the west, and JEN's Heidelberg Zone Substation (**HB**) in the east.

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 2028, the FF supply area will become an isolated 6.6 kV network.

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

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



3. 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 22 kV subtransmission loop. Table 3-1 shows the current rating of the subtransmission lines supplying FF.

Table 3-1: BTS-FF 22 kV Subtransmission line rating

	Summer (MVA)	Winter (MVA)
BTS-FF 181	11.4	12.6
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 under contingency conditions due to an increase in demand around the Fairfield supply area. Maximum demand at FF is expected to grow on average at 4.2% per annum during 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 (a mixture of apartments and townhouses), together with major multi-level commercial and retail facilities.

With plans to replace the existing FF No.3 transformer by 2025, there is sufficient 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 contingency 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 22kV subtransmission lines (N-2) under the following single contingency events will lead to an overload on the remaining single line, well above its thermal capacity rating:
  - outage of 1,820 m long BTS-FF 184 and BTS-FF 188 underground cables in a common trench;
  - outage of 1,760 m long BTS-FF 184 and BTS-FF 188 double circuit pole line; or
  - outage of 600 m long BTS-FF 181 and BTS-FF 184 double circuit pole line.

Major safety and reliability 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, Table 3-3 and Table 3-4 show the forecast maximum demand of the BTS-FF 22 kV subtransmission lines under N, N-1 and N-2 conditions respectively until 2032.

Table 3-2: Subtransmission line 10% PoE MD forecast (MVA) under system normal (N) – Base Case

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	6.0	6.3	6.8	7.0	7.1	7.3	7.6	7.9	8.3	8.7
BTS-FF 188	9.5	10.0	10.7	11.1	11.3	11.5	11.9	12.4	13.1	13.8
BTS-FF 184	9.8	10.3	11.0	11.4	11.6	11.8	12.2	12.7	13.4	14.1

Table 3-3: Subtransmission line 10% PoE MD forecast (MVA) under outage condition (N-1) – Base Case

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	9.9	10.5	11.3	11.7	11.9	12.1	12.6	13.1	13.9	14.6
BTS-FF 188	15.6	16.6	17.8	18.3	18.7	19.1	19.8	20.7	21.9	23.0
BTS-FF 184	15.8	16.8	18.0	18.5	18.9	19.4	19.9	20.8	22.1	23.2

Table 3-4: Subtransmission line 10% PoE MD forecast (MVA) under outage condition (N-2) – Base Case

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	25.0	26.5	28.4	29.4	29.9	30.4	31.4	32.8	34.7	36.5
BTS-FF 188	25.0	26.5	28.4	29.4	29.9	30.4	31.4	32.8	34.7	36.5

Notes:

1. The loading above the line rating is highlighted in red to show that the lines are forecast to be overloaded.
2. The maximum demand forecasts under outage conditions (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.
3. The maximum demand forecast under outage condition (N-2) only applies to outages of lines sharing a common pole, or installed in a common trench. All N-2 outages involve BTS-FF 184.

The subtransmission lines supplying FF is expected to exceed their rating under a system-normal condition from summer 2030 – 2031.All three BTS-FF 22 kV lines are forecast to be operating above 100% of their thermal rating under contingency conditions, with the level of overload expected to increase over the forecast period. The load-at-risk under a single contingency condition in 2023-24 could impact supply to up to 1,400 customers.

BTS-FF 184 and BTS-FF 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 an increased risk of breaching statutory clearances (green book) 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 circuits). BTS-FF 184 and BTS-FF 188 are also forecasted to exceed their thermal N rating from summer 2030-2031.

Due to the double-circuit line construction of the subtransmission lines as shown in Figure 2–1, there is a chance of simultaneously losing two 22 kV subtransmission lines (N-2) during a single contingency event, such as a vehicle collision into a pole or an underground cable dig-in. 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 5,900 customers supplied by FF.

Table 3–5 presents the forecast reliability risk and the energy losses for the BTS-FF subtransmission lines.

Table 3–5: Annual forecast reliability of supply risk and energy losses – Base Case

Year	(N-1) Load-at-risk (MVA)	(N-1) Hours at Risk (h)	(N-2) Load-at-risk (MVA)	(N-2) Hours at Risk (h)	Expected Unserved Energy (EUE) (MWh)	Cost of Expected Unserved Energy ($k)[9]	Annual Energy Losses (MWh)	Cost of Annual Energy Losses ($k)[8]
2023	2.7	21	13.6	3271	5	162	775	47
2024	3.7	24	15.1	4193	8	287	864	52
2025	4.9	38	17.0	4916	17	608	992	60
2026	5.5	56	18.0	5174	24	844	1,052	63
2027	6.1	68	18.5	5314	30	1045	1,097	66
2028	6.8	82	19.0	5455	36	1260	1,141	68
2029	7.8	102	20.0	5661	48	1662	1,216	73
2030	9.2	154	21.4	6003	70	2424	1,317	79
2031	11.6	233	23.3	6414	112	3908	1,480	89
2032	14.1	351	25.1	6793	198	6894	1,638	98

Notes:

1. Load-at-risk is specified at a 10% PoE forecast summer maximum demand.
2. Expected Unserved Energy is specified as a 30% weighting on the 10% PoE forecast maximum demand, and a 70% weighting on the 50% PoE forecast maximum demand, for both summer and winter seasons.

[9] Real 2023 dollars.

4. Identification of non-network options

Potential non-network options that could meet the project objectives (as envisaged in the RIT-D Application Guidelines Section 6.1) were considered based on two alternatives - Generation/Storage and Demand Management. The National Electricity Rules (NER) require RIT-D project proponents to investigate whether a non-network option (or combination of non-network measures) is capable of avoiding the need for investment in a network solution or at least allowing a smaller network investment to meet the identified need.

A viable non-network solution would involve implementing measures capable of meeting the identified need to maintain reliability in the Fairfield and Alphington supply area. Potential non-network scenarios are:

1. Meeting the identified need in its entirety through a non-network solution
2. Installing some network assets and meeting the remaining capacity through a non-network solution.

4.1 Assessment approach and findings

The criteria used to assess the potential credibility of non-network options were:

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

Figure 4–1 shows the rating scale applied for assessing non-network options.

Figure 4–1: Assessment Rating Criteria

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

The Non-Network Options Report for addressing the need considered whether a non-network option (or combination of non-network measures) could provide a viable way to avoid or reduce the scale of network investment in a way that meets the identified need. A non-network option could comprise a single non-network measure (e.g., installation of renewable or embedded energy generation) or a combination of measures (e.g., generation plus demand management).

Figure 4–2 shows the assessment of non-network options against the RIT-D criteria. The assessment shows that a credible non-network option was not identified (considered both in isolation and in combination with network solutions). Section 4.2 summarises each non-network option in more detail.

Figure 4–2: **Assessment of non-network options against RIT-D criteria**

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and/or Storage options				
1.1 Gas turbine power station				
1.2a Generation using renewables (Solar)				
1.2b Generation using renewables (Wind)				
1.3 Dispatchable generation (large customer)				
1.4 Customer energy storage				
2.0 Demand Management options				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

4.2 Non-network assessment commentary

As part of the RIT-D process, JEN considered the credibility of potential non-network options as alternatives to network options. A Non-Network Options Report, published on JEN's website on 22 September 2021, was prepared to establish whether a non-network solution is potentially available to address the identified need. The Non-Network Options Report was predicated on the need for a non-network option to reduce the expected unserved energy risk that would otherwise have been addressed by a network solution.

From the consultation on the Non-Network Options Report that closed on 15 December 2021, JEN did not receive any submissions that identified a viable non-network alternative solution. JEN has determined that neither a non-network option on its own, nor one that forms a material part of another option, is credible to address the identified need. The reasons for this determination are:

1. JEN did not receive any submissions on the Non-Network Options Report that proposed a viable third-party non-network alternative solution;
2. JEN is not able to materially address the need through by using its own demand management programs; and
3. An economically viable network solution exists to address the need.

In accordance with the NER requirements, we note that these reasons are not dependent on any particular assumptions or methodologies.

5. Network options assessed in this RIT-D

This section outlines the credible network options that have been considered in the RIT-D and outlines the proposed works associated with each credible option.

Jemena has identified below, potential credible network options to alleviate the current and emerging capacity overload limitations on the BTS-FF 22 kV subtransmission lines:

- **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**: Augment the BTS-FF 22 kV subtransmission loop by installing a new fourth line from BTS to FF using a single cable. This will assist in reducing the load-at-risk and losses on the BTS-FF lines.
- **Option 4**: Augment the BTS-FF 22 kV subtransmission loop by installing a new fourth line from BTS to FF using twin cables. This will assist in reducing the load-at-risk and losses on the BTS-FF lines; and
- **Option 5**: Combine the existing BTS-FF 184 and BTS-FF 188 lines and augment the BTS-FF 22 kV subtransmission loop by installing a new third line from BTS to FF using twin cables. This will assist in reducing the load-at-risk and losses on the BTS-FF lines.

5.1 Option 1: "Do Nothing" (Base Case)

The Base Case option gives the basis for comparing the cost-benefit assessment of each credible option. The Base Case is presented as a "Do Nothing" option, where we would continue managing risk through involuntary load shedding but not initiate any project.

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;
- intangible costs to Jemena arising from negative publicity generated due to longer than expected supply restoration times; and
- increasing energy losses.

Table 3–5 summarises the annual value of the EUE and energy losses for the BTS-FF 22 kV subtransmission lines for the Base Case over the next ten years (2023-2032). Table 3–5 shows that the forecast cost of EUE and energy losses combined increase from $339k in 2023-24 to $6,992k in 2031-32.

The Base Case ("Do Nothing") option is assumed to have zero benefits.

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 66kV 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 66kV subtransmission loop is fully rated, hence 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 establish a new 66 kV line from TSTS to HB. Given that Templestowe and Heidelberg areas are densely populated and are outside the Jemena distribution network, it is assumed that undergrounding the subtransmission line might be the only acceptable solution.

The proposed scope of works include:

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

The total cost to establish a new subtransmission line from TSTS to HB is estimated to be $27.6 million (real, 2023). The annualised cost for this option including operational and maintenance costs is estimated to be $1.7 million.

After completing the proposed project, there is estimated to be a 84% reduction in the overall EUE on the FF subtransmission lines for the next ten years, leaving a residual amount of N-2 load-at-risk on BTS-FF 181 and BTS-FF 188, and no N-1 risk. This option addresses the majority of the network need.

5.3 Option 3: Augment BTS-FF 22kV loop with fourth 22 kV line (single cable)

This option involves establishing a fourth 22kV line from BTS to FF to augment the BTS-FF 22kV subtransmission loop by installing a new single 22 kV underground cable from BTS to FF, to be known as the BTS-FF 180 line. Given that, FF is located in a rather densely populated area, it is assumed that the new BTS-FF 180 22 kV line will have to be fully undergrounded. BTS does not have any spare 22 kV circuit breakers, hence the 22 kV bus at BTS will 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 22kV 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 to establish a new subtransmission feeder exit for BTS-FF 180;
- install 1 x 22kV circuit breaker within the FF 22kV switch-room to provide a feeder incomer connection for BTS-FF 180;
- supply and install approximately 4.1 km of new 1 x 3c 300mm^2 Al XLPE underground cable from BTS-FF 180 feeder CBs at BTS to FF; and
- make the connection to FF between 22 kV CB A and the new CB as shown in Figure 5–1.

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

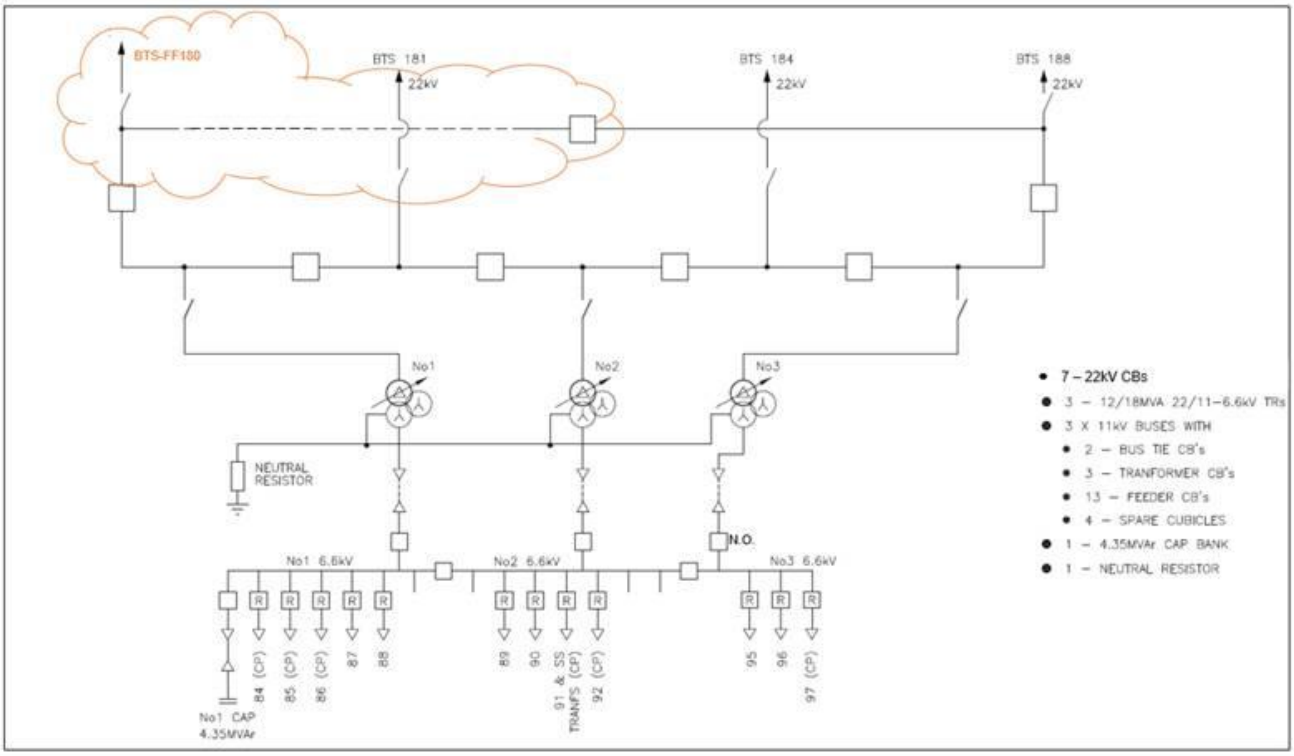


Table 5-1 below shows the new rating of the subtransmission lines on completion of this scope.

Table 5-1: Subtransmission Line Rating (MVA) on completion of Option 3

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)	15.2	15.2

The total cost to establish a new BTS-FF 180 subtransmission line from BTS to FF is estimated to be $9.86 million (real, 2023). The annualised cost for this option including operational and maintenance costs is estimated to be $0.61 million.

After completing the proposed project, there is estimated to be an 94% reduction in the overall EUE on the FF subtransmission lines for the next ten years, leaving a residual amount of N-2 load-at-risk on BTS-FF 180, and no N-1 risk. This option also improves the energy losses on the BTS-FF lines by 25%. This option addresses the majority of the network need.

5.4 Option 4: Augment BTS-FF 22kV loop with fourth 22 kV line (twin cable)

This option involves establishing a fourth 22kV line from BTS to FF to augment the BTS-FF 22kV subtransmission loop by installing in parallel, new twin 22 kV underground cables from BTS to FF, to be known as the BTS-FF 180 line. 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, hence the 22 kV bus at BTS will 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 22kV 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 to establish a new subtransmission feeder exit for BTS-FF 180;
- install 1 x 22kV circuit breaker within the FF 22kV switch-room to provide a feeder incomer connection for the two parallel cables forming BTS-FF 180;
- supply and install approximately 4.1 km of new 2 x 3c 300mm^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 in Figure 5–2.

Figure 5–2: FF single-line diagram after connection of fourth 22kV subtransmission line

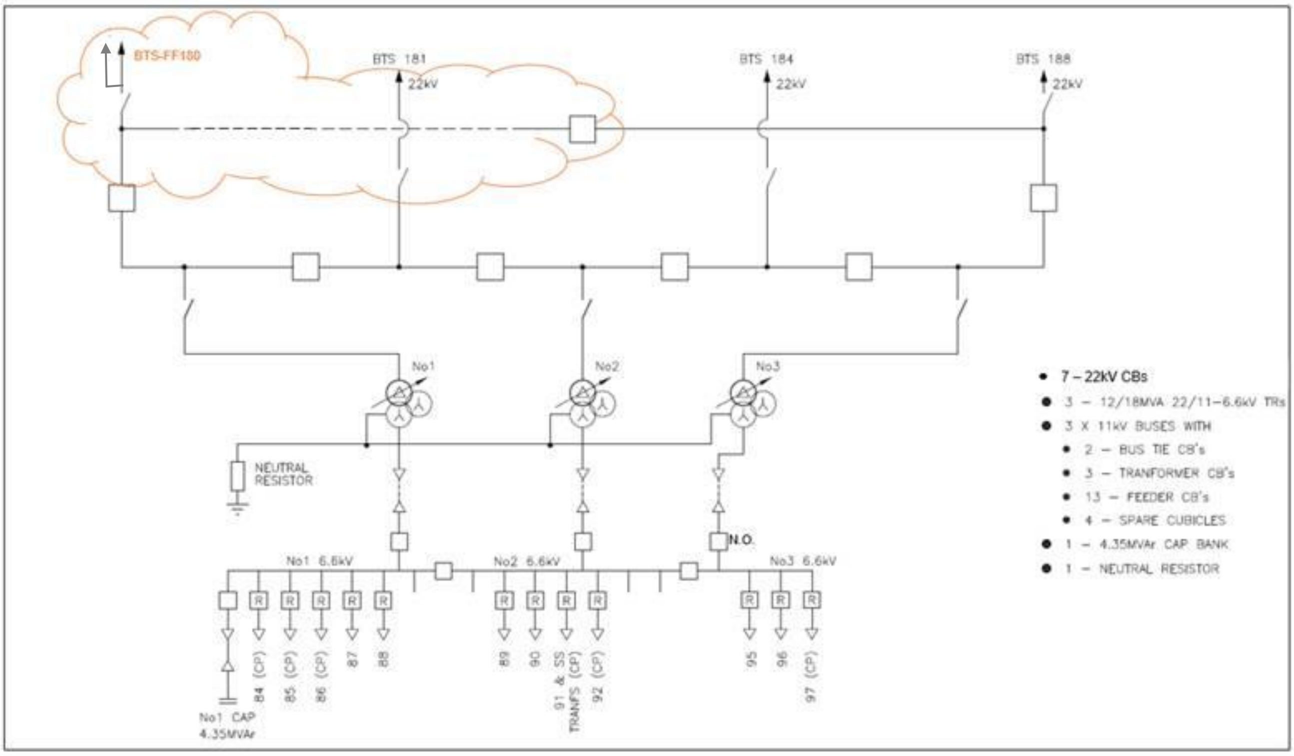


Table 5-2 below shows the new rating of the subtransmission lines on completion of this scope.

Table 5-2: 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

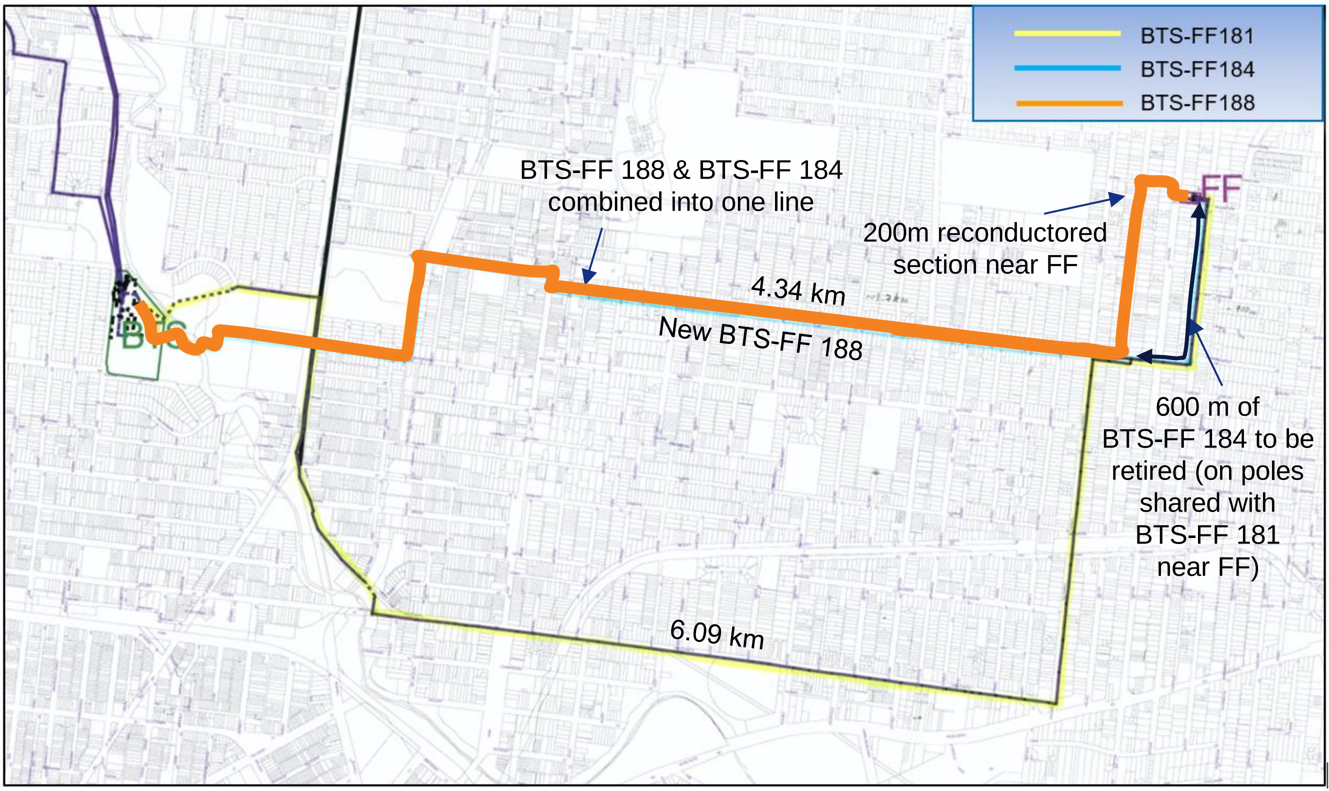
The total cost to establish a new BTS-FF 180 subtransmission line from BTS to FF is estimated to be $11.45 million (real, 2023). The annualised cost for this option including operational and maintenance costs is estimated to be $0.71 million.

On completion of the proposed project, there is estimated to be a 100% reduction in the overall EUE on the FF subtransmission lines for the next ten years. This option also improves the energy losses on the BTS-FF lines by 40%. This option addresses the network need in its entirety.

5.5 Option 5: Combine BTS-FF 184 and BTS-FF 188 and Augment BTS-FF 22kV loop with a third 22 kV line (twin cable)

This option involves paralleling the sections of BTS-FF 184 and BTS-FF 188 that are in a common cable trench or on shared double circuit poles (3,500m in total), and combining them to form an upgraded BTS-FF 188 feeder. This will also require a 200 m section of BTS-FF 188 overhead line between FF and pole 38 to be reconductored to 37/3.75AAC to increase the rating. The existing 600 m section of BTS-FF 184 sharing the same poles as BTS-FF 181 near FF shall be retired. This consolidation work is shown in Figure 5–3.

Figure 5–3: Consolidating BTS-FF 184 and BTS-FF 188 22 kV subtransmission lines into one line



The option also involves establishing a third 22kV line from BTS to FF to augment the BTS-FF 22kV subtransmission loop by installing new twin parallel 22 kV underground cables from BTS to FF, to be known as the BTS-FF 184 line. 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. The existing BTS-FF 184 CB at BTS and the associated BTS-FF 184 incomer at FF shall be used for this new BTS-FF 184 line, avoiding the need for new 22 kV circuit breakers, and *avoiding* the need for 22 kV bus extensions at BTS.

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 three geographically diverse 22 kV lines from BTS to FF will eliminate this risk.

The proposed scope of works include:

- parallel the sections of BTS-FF 184 and BTS-FF 188 that are in a common cable trench or on shared double circuit poles (3,500m in total), by relocating the existing BTS-FF 184 cable at BTS to the BTS-FF 188 CB, and connecting the two circuits at pole 31, to form a combined BTS-FF 188 feeder;
- reconductor the 750 m section of BTS-FF 188 undersized overhead line between FF and pole 31 with 37/3.75AAC to increase the summer rating of BTS-FF 188 to minimum of 700A (26.6 MVA);
- retire the existing 600 m section of BTS-FF 184 overhead conductor sharing the same poles as BTS-FF 181 from pole 78 to FF, and disconnect from the BTS-FF 184 incomer connection at FF; and
- supply and install approximately 4.1 km of new 2 x 3c 300mm^2 Al XLPE underground cable from BTS-FF 184 feeder CB at BTS, and connect to BTS-FF 184 incomer at FF.

Table 5-3 below shows the new rating of the subtransmission lines on completion of this scope.

Table 5-3: Subtransmission Line Rating (MVA) on completion of Option 5

Circuit	Summer	Winter
BTS-FF 181	11.4	13.0
BTS-FF 188 (Existing 188 and 184 combined)	26.6	26.6
BTS-FF 184 (New Circuit)	30.5	30.5

The total cost to establish a new BTS-FF 184 subtransmission line from BTS to FF, and combining the existing BTS-FF 188 and BTS 184 into a single BTS-FF 188 line, is estimated to be $10.58 million (real, 2023). The annualised cost for this option including operational and maintenance costs is estimated to be $0.66 million.

On completion of the proposed project, there is estimated to be a 100% reduction in the overall EUE on the FF subtransmission lines for the next ten years. This option also improves the energy losses on the BTS-FF lines by 40%. This option addresses the network need in its entirety.

6. Market benefit assessment method

This section outlines the method that JEN 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.

6.1 Market benefit classes quantified for this RIT-D

This section outlines the classes of market benefits that JEN considers will have a material impact on this RIT-D, and have therefore quantified.

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

- involuntary load shedding and customer interruptions; and
- electrical energy losses.

6.1.1 Involuntary load shedding and customer interruptions

Involuntary load shedding is where a customer's load is interrupted (switched off or disconnected) from the network without their agreement or prior warning. Involuntary load shedding can occur unexpectedly due to a network outage event or safety issue, or pre-emptively to maintain network loading to within asset capabilities. The aim of a credible option, either a network or non-network solution, is to provide a reduction in the amount of involuntary load shedding expected compared with the Base Case.

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:

- EUE (in MWh) being the expected involuntary load shedding required assuming the credible option is completed, multiplied by the
- VCR (in $/MWh), which is calculated from the results of the Australian Energy Regulator's (**AER**) published VCRs and JEN's customer load composition.

JEN 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 credible network outage conditions.

In evaluating the EUE for involuntary load shedding and customer interruptions costs, the following assumptions are used for all the options analysed in this RIT-D for a single event:

- line outage frequency, which is 0.093 outages per kilometre of line length, per year;
- line outage average duration of 4 hours, per outage;
- double line outage frequency of 0.019 outages per length of exposed line on the same route, per year;
- double line outage duration of 4 days, per outage for the total loss of a pole and cable dig-in;

JEN has captured the reduction in involuntary load shedding as a market benefit of the credible options assessed in this RIT-D. They have been included in the net economic benefit assessments summarised in Section 7.

6.1.2 Electrical energy losses

The change in electrical energy losses between the Base Case and each option is small compared with the reliability benefit but it is material in nature. Considering the electrical energy losses may change the timing of the options given the proportionality test. Therefore, the market benefits associated with electrical energy losses are considered as part of this RIT-D, and have therefore been included in the net economic benefit assessments summarised in Section 7.

A reduction in electrical energy losses, relative to the Base Case, results in a positive contribution to the market benefits of the credible option being assessed. The electrical energy losses of a credible option are derived by the:

- Annual energy losses (in MWh), which are the amount of energy dissipated as heat as a result of electrical current flowing through electrical resistance, assuming the credible option is completed, multiplied by the
- Value of energy losses (in $/MWh), which is calculated from the most recent annual weighted average NEM wholesale electricity price.

6.2 Market benefit classes not relevant to this RIT-D

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

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

6.2.1 Timing of expenditure

JEN has assessed that 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 need in the Fairfield and Alphington supply area.

6.2.2 Voluntary load curtailment

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

An increase in voluntary load curtailment, compared with the Base Case, results in a negative contribution (a cost) to the market benefits of the credible option. JEN has assessed the potential for voluntary load curtailment in the Fairfield and Alphington supply area. This assessment showed there was insufficient potential for voluntary load curtailment to meet the need. Therefore, this market benefit was not quantified as it was considered to be not material for differentiating between options.

6.2.3 Changes in load transfer capacity and embedded generators

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

Furthermore, the location of the FF 6.6kV zone substation being surrounded mainly by 11kV zone substations means there is little opportunity to consider changes in load transfer capacity. FF is forecast to have no load transfer capability within the forecasting period.

For these reasons, this market benefit was not quantified as it was considered to be not material for differentiating between options.

6.2.4 Costs to other parties

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

6.2.5 Option value

The AER RIT-D guidelines[10] 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"*.

The Fairfield and Alphington supply area need relates to maintaining supply reliability. The area currently has sufficient load-at-risk to economically justify an augmentation and has growth levels significantly high enough from new customer connections that there is a very high probability that the existing load-at-risk will continue to grow in magnitude. With no identified non-network solutions, there is no value in retaining flexibility in this instance. JEN has therefore not attempted to estimate any additional option value market benefit for this RIT-D assessment.

6.3 Valuing market benefits and sensitivities

Clause 5.17.1 of the NER requires that the RIT-D assessment be based on a cost-benefit analysis that includes an assessment of a reasonable range of scenarios of future supply and demand.

Supply reliability has been quantified in this RIT-D for each option based on reference to the demand forecasts.

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

JEN 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; and
- discount rate.

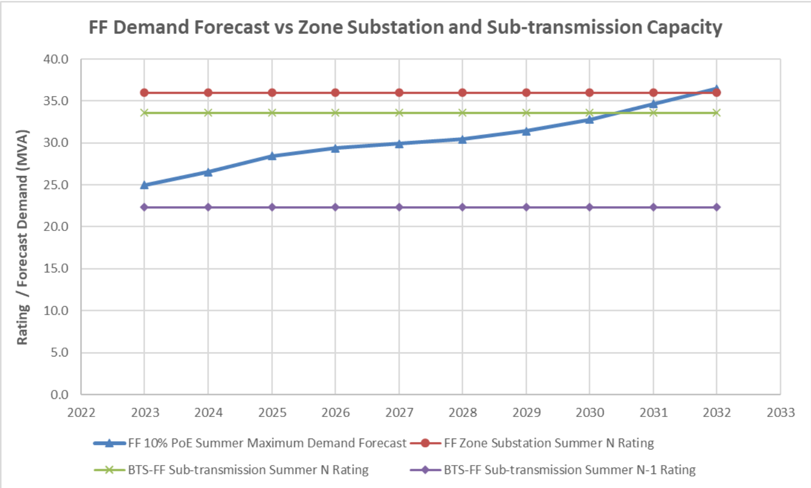
[10] AER, *Application guidelines for regulatory investment test for distribution (RIT-D)*, August 2022.

6.3.1 Maximum demand growth rate

The electricity maximum demand forecasts used in the preparation of this report are JEN's 2022 maximum demand forecasts. Our central forecast for maximum demand at the FF zone substation is an average increase of 4.2% over the next five-year period.

Figure 6–1 shows the forecast summer peak demand for FF under 10% POE conditions relative to the zone substation and subtransmission ratings.

Figure 6–1: Summer maximum demand forecast vs capacity for FF and its subtransmission lines



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

6.3.2 Value of Customer Reliability (VCR)

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[11] published in December 2022. Therefore, the composite VCR for FF has been derived as shown in Table 6–1.

Table 6–1: VCR for FF

Sector	AER VCR ($/kWh)	Annual Energy consumption (%)	Energy Consumption weighted VCR ($/kWh)
Residential (Climate zone 6 CBD and Suburban)	22.86	57	12.96
Agricultural	40.74	0	0.00
Commercial	47.9	38	18.30
Industrial	68.63	5	3.50
Composite of all sectors (2022)			**34.76**

Sensitivities to the base VCR of ±10% have been considered.

11 AER, Values of Customer Reliability Final Report on VCR values, December 2022.

6.3.3 Capital costs

The network project capital costs have been estimated by JEN's internal estimation teams. Consideration has been given to recent similar projects and expected costs based on site-specific construction complexities and industry experience. Capital costs are presented in real 2023 dollars.

These capital cost estimates have been prepared for planning purposes and are therefore subject to an estimated range of ±30%. A range of +30% to -10% of the base capital cost has been applied to the sensitivity studies for this RIT-D.

6.3.4 Discount rate

A discount rate of 5.17% has been applied in assessing the Net Present Value (NPV) assessment of credible options and calculation of annualised costs. 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 of ±1% have been considered.

6.3.5 Value of energy losses

The value of energy losses assumed in this assessment is $60/MWh from the most recent annual weighted average NEM wholesale electricity price.

No sensitivities are applied to the losses in this assessment because no credible change in the value of losses changes the preferred option or its optimum timing.

7. Options analysis

This section presents the Base Case and summarises the economic analysis results of the credible options. The net economic benefit analysis has been assessed considering the network reliability risks and expected costs for the ten years from 2023 to 2032. Each potential option has been ranked according to its net economic benefit, which is the difference between the present value of market benefits and the present value of costs within the assessment period.

7.1 Involuntary load shedding and energy losses

7.1.1 Option 1: "Do Nothing" (Base Case)

This option considers the impact of a "Do Nothing" scenario, which would include no additional investment in the Fairfield and Alphington supply area. The capability of the subtransmission lines in the area for the Base Case is presented in Table 3-1.

The network capacity limitations under the Base Case are highlighted in Table 3-2 and

Table 3-3 against each forecast maximum demand. The value of the network limitations under Option 1 is presented in Table 3–5.

7.1.2 Option 2: Reinforce supply to FF from HB

Under Option 2, it is expected that there will be a net load transfer of up to 10 MW by the end of the forecast period from FF to HB to reduce the EUE. The capability of the subtransmission lines in the area for Option 2 is presented in Table 3-1.

The forecast maximum demand following completion of Option 2, and any residual network capacity limitations (highlighted in red) are presented in Table 7-1, Table 7-2 and Table 7-3 for N, N-1 and N-2 conditions respectively.

Table 7-1: Subtransmission line 10% PoE MD forecast (MVA) under system normal (N) – Option 2

Line	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	3.9	4.3	4.5	4.7	4.8	5.1	5.4	5.8	6.3
BTS-FF 188	6.1	6.8	7.2	7.4	7.6	8.0	8.5	9.2	9.9
BTS-FF 184	6.3	7.0	7.3	7.6	7.8	8.1	8.6	9.4	10.1

Table 7-2: Subtransmission line 10% PoE MD forecast (MVA) under outage (N-1) – Option 2

Line	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	6.4	7.2	7.5	7.7	8.0	8.4	8.9	9.7	10.4
BTS-FF 188	10.1	11.3	11.9	12.2	12.6	13.2	14.1	15.3	16.4
BTS-FF 184	10.2	11.4	12.0	12.3	12.8	13.3	14.2	15.4	16.6

Table 7-3: Subtransmission line 10% PoE MD forecast (MVA) under outage (N-2) – Option 2

Line	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	16.1	18.0	19.0	19.5	20.0	21.0	22.4	24.3	26.1
BTS-FF 188	16.1	18.0	19.0	19.5	20.0	21.0	22.4	24.3	26.1

The value of the residual network capacity limitations and energy losses after completion of Option 2 is presented in Table 7–4.

Table 7–4: Annual forecast reliability of supply risk and energy losses – Option 2

Year	(N-1) Load-at-risk (MVA)	(N-1) Hours at Risk (h)	(N-2) Load-at-risk (MVA)	(N-2) Hours at Risk (h)	Expected Unserved Energy (EUE) (MWh)	Cost of Expected Unserved Energy ($k)[12]	Annual Energy Losses (MWh)	Cost of Annual Energy Losses ($k)[10]
2024	0.0	0	4.7	461	1	32	864	52
2025	0.0	0	6.6	541	2	67	992	60
2026	0.0	0	7.6	569	3	93	1052	63
2027	0.0	0	8.1	585	3	115	1097	66
2028	0.0	0	8.6	600	4	139	1141	68
2029	0.2	2	9.6	623	5	183	1216	73
2030	1.1	9	11.0	660	8	267	1317	79
2031	2.3	19	12.9	706	12	430	1480	89
2032	3.5	21	14.7	747	22	758	1638	98

7.1.3 Option 3: Augment BTS-FF 22kV loop with fourth 22 kV line (single cable)

Under Option 3, it is expected that there will be an increase in subtransmission capacity to FF, reducing the EUE. The capability of the subtransmission lines in the area for Option 3 is presented in Table 5-1.

The forecast maximum demand following completion of Option 3, and any residual network capacity limitations (highlighted in red) are presented in Table 7-5, Table 7-6 and Table 7-7 for N, N-1 and N-2 conditions respectively.

Table 7-5: Subtransmission line 10% PoE MD forecast (MVA) under system normal (N) – Option 3

Line	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	4.3	4.6	4.7	4.8	4.9	5.1	5.3	5.6	5.9
BTS-FF 188	6.7	7.2	7.4	7.5	7.7	8.0	8.3	8.8	9.2
BTS-FF 184	6.9	7.4	7.6	7.8	7.9	8.2	8.5	9.0	9.5
BTS-FF 180	8.8	9.4	9.7	9.9	10.1	10.4	10.9	11.5	12.1

Table 7-6: Subtransmission line 10% PoE MD forecast (MVA) under outage (N-1) – Option 3

Line	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	6.4	6.8	7.0	7.2	7.3	7.6	7.9	8.3	8.8
BTS-FF 188	10.0	10.7	11.0	11.3	11.5	11.9	12.3	13.1	13.8
BTS-FF 184	10.3	11.0	11.4	11.6	11.8	12.2	12.7	13.5	14.2
BTS-FF 180	11.9	12.7	13.1	13.4	13.6	14.1	14.7	15.5	16.3

12 Real 2023 dollars.

Table 7-7: Subtransmission line 10% PoE MD forecast (MVA) under outage (N-2) – Option 3

Line	2024	2025	2026	2027	2028	2029	2030	2031	2032
BTS-FF 181	8.7	9.3	9.6	9.8	10.0	10.3	10.7	11.4	12.0
BTS-FF 180	18.0	19.2	19.8	20.2	20.6	21.3	22.2	23.5	24.7

The value of the residual network capacity limitations and energy losses after completion of Option 3 is presented in Table 7–8.

Table 7–8: Annual forecast reliability of supply risk and energy losses – Option 3

Year	(N-1) Load-at-risk (MVA)	(N-1) Hours at Risk (h)	(N-2) Load-at-risk (MVA)	(N-2) Hours at Risk (h)	Expected Unserved Energy (EUE) (MWh)	Cost of Expected Unserved Energy ($k)[13]	Annual Energy Losses (MWh)	Cost of Annual Energy Losses ($k)[11]
2024	0.0	0	2.8	360	0	17	648	39
2025	0.0	0	4.0	461	1	36	744	45
2026	0.0	0	4.6	541	1	51	789	47
2027	0.0	0	5.0	569	2	63	823	50
2028	0.0	0	5.4	585	2	76	856	51
2029	0.0	0	6.1	600	3	100	912	55
2030	0.0	0	7.0	623	4	145	988	59
2031	1.5	2	8.3	660	7	234	1110	67
2032	4.5	5	9.5	706	12	414	1229	74

7.1.4 Option 4: Augment BTS-FF 22kV loop with fourth 22 kV line (twin cable)

Under Option 4, it is expected that there will be an increase in subtransmission capacity to FF, reducing the EUE. The capability of the subtransmission lines in the area for Option 4 is presented in Table 5-2.

The forecast maximum demand following completion of Option 4, and any residual network capacity limitations (highlighted in red) are presented in Table 7-9, Table 7-10 and Table 7-11 for N, N-1 and N-2 conditions respectively.

Table 7-9: Subtransmission line 10% PoE MD forecast (MVA) under system normal (N) – Option 4

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031
BTS-FF 181	3.1	3.3	3.5	3.6	3.7	3.7	3.7	3.7	3.7
BTS-FF 188	4.9	5.1	5.4	5.6	5.7	5.8	5.8	5.8	5.8
BTS-FF 184	5.0	5.3	5.6	5.8	5.9	6.0	6.0	6.0	6.0
BTS-FF 180	12.9	13.7	14.5	15.0	15.3	15.5	15.5	15.6	15.6

[13] Real 2023 dollars.

Table 7-10: Subtransmission line 10% PoE MD forecast (MVA) under outage (N-1) – Option 4

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031
BTS-FF 181	6.2	6.5	6.9	7.2	7.3	7.4	7.4	7.4	7.4
BTS-FF 188	9.7	10.3	10.9	11.3	11.5	11.6	11.6	11.7	11.7
BTS-FF 184	10.0	10.6	11.2	11.6	11.8	12.0	12.0	12.0	12.0
BTS-FF 180	16.0	17.0	17.9	18.6	19.0	19.2	19.2	19.3	19.3

Table 7-11: Subtransmission line 10% PoE MD forecast (MVA) under outage (N-2) – Option 4

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031
BTS-FF 181	6.2	6.5	6.9	7.2	7.3	7.4	7.4	7.4	7.4
BTS-FF 180	20.9	22.1	23.4	24.3	24.7	25.0	25.1	25.1	25.1

The value of the residual network capacity limitations and energy losses after completion of Option 4 is presented in Table 7–12.

Table 7–12: Annual forecast reliability of supply risk and energy losses – Option 4

Year	(N-1) Load-at-risk (MVA)	(N-1) Hours at Risk (h)	(N-2) Load-at-risk (MVA)	(N-2) Hours at Risk (h)	Expected Unserved Energy (EUE) (MWh)	Cost of Expected Unserved Energy ($k)[14]	Annual Energy Losses (MWh)	Cost of Annual Energy Losses ($k)[12]
2024	0.0	0.0	0.0	0.0	0.0	0.0	518	31
2025	0.0	0.0	0.0	0.0	0.0	0.0	595	36
2026	0.0	0.0	0.0	0.0	0.0	0.0	631	38
2027	0.0	0.0	0.0	0.0	0.0	0.0	658	40
2028	0.0	0.0	0.0	0.0	0.0	0.0	685	41
2029	0.0	0.0	0.0	0.0	0.0	0.0	730	44
2030	0.0	0.0	0.0	0.0	0.0	0.0	790	47
2031	0.0	0.0	0.0	0.0	0.0	0.0	888	53
2032	0.0	0.0	0.0	0.0	0.0	0.0	983	59

7.1.5 Option 5: Combine BTS-FF 184 and BTS-FF 188 and Augment BTS-FF 22kV loop with a third 22 kV line (twin cable)

Under Option 5, it is expected that there will be an increase in subtransmission capacity to FF, reducing the EUE. The capability of the subtransmission lines in the area for Option 5 is presented in Table 5-3.

The forecast maximum demand following the completion of Option 5, and any residual network capacity limitations (highlighted in red) are presented in Table 7-13, and Table 7-14 for N and N-1 conditions respectively. There are no N-2 contingencies for this option.

[14] Real 2023 dollars.

Table 7-13: Subtransmission line 10% PoE MD forecast (MVA) under system normal (N) – Option 5

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031
BTS-FF 181	3.1	3.3	3.5	3.6	3.7	3.7	3.7	3.7	3.7
BTS-FF 188	9.9	10.4	11.0	11.5	11.6	11.8	11.8	11.9	11.9
BTS-FF 184	12.9	13.7	14.5	15.0	15.3	15.5	15.5	15.6	15.6

Table 7-14: Subtransmission line 10% PoE MD forecast (MVA) under outage (N-1) – Option 5

Line	2023	2024	2025	2026	2027	2028	2029	2030	2031
BTS-FF 181	6.2	6.5	6.9	7.2	7.3	7.4	7.4	7.4	7.4
BTS-FF 188	14.7	15.6	16.4	17.1	17.4	17.6	17.6	17.7	17.7
BTS-FF 184	20.9	22.1	23.4	24.3	24.7	25.0	25.1	25.1	25.1

The value of the residual network capacity limitations and energy losses after completion of Option 5 is presented in Table 7–15.

Table 7–15: Annual forecast reliability of supply risk and energy losses – Option 5

Year	(N-1) Load-at-risk (MVA)	(N-1) Hours at Risk (h)	(N-2) Load-at-risk (MVA)	(N-2) Hours at Risk (h)	Expected Unserved Energy (EUE) (MWh)	Cost of Expected Unserved Energy ($k)[15]	Annual Energy Losses (MWh)	Cost of Annual Energy Losses ($k)[13]
2024	0.0	0.0	0.0	0.0	0.0	0.0	518	31
2025	0.0	0.0	0.0	0.0	0.0	0.0	595	36
2026	0.0	0.0	0.0	0.0	0.0	0.0	631	38
2027	0.0	0.0	0.0	0.0	0.0	0.0	658	40
2028	0.0	0.0	0.0	0.0	0.0	0.0	685	41
2029	0.0	0.0	0.0	0.0	0.0	0.0	730	44
2030	0.0	0.0	0.0	0.0	0.0	0.0	790	47
2031	0.0	0.0	0.0	0.0	0.0	0.0	888	53
2032	0.0	0.0	0.0	0.0	0.0	0.0	983	59

7.2 Net economic benefits

JEN's options assessment considered project and ongoing incremental operational costs, EUE (reliability) costs based on forecast demand and network capability, and energy loss costs. A summary of the present value cost analysis assessed for each option is presented in Table 7-16.

15 Real 2023 dollars.

Table 7-16: Summary of Present Value Cost Analysis (real million, $2023)

Option	Capital Cost	Incremental O&M	EUE Cost	Losses Cost	Total Cost	Ranking
Option 1	0.0	0.0	68.86	1.25	70.11	5
Option 2	21.45	3.01	11.02	1.25	37.78	4
Option 3	9.38	1.42	4.02	0.94	15.85	3
Option 4	10.35	1.64	0.00	0.75	13.36	2
Option 5	10.06	1.52	0.00	0.75	12.43	**1**

Net economic benefits are the market benefits (avoided EUE costs relative to "Do Nothing") less the costs to implement the credible option. The assessment results in Table 7–17 show that the feasible option that maximises the net economic benefit is Option 5. This option is JEN's proposed preferred option because it addresses the identified need and maximises the net economic benefit compared with the other options considered in this RIT-D.

Table 7–17: Present Value of Net Economic Benefits of each option (real million, $2023)

Option	PV Cost	PV Benefits	NPV	Ranking
Option 1: Do Nothing (Base Case)	0.00	0.00	0.00	5
Option 2: Reinforce supply to FF from HB	24.09	47.73	23.64	4
Option 3: Augment BTS-FF 22kV loop with fourth 22 kV line (single cable)	10.65	56.71	46.05	3
Option 4: Augment BTS-FF 22kV loop with fourth 22 kV line (twin cable)	11.69	59.80	48.11	2
Option 5: Combine BTS-FF 184 and BTS-FF 188 and Augment BTS-FF 22kV loop with a third 22 kV line (twin cable)	11.42	60.37	48.95	**1**

7.3 Preferred option optimal timing

The optimum timing occurs in the year when the benefits of the preferred option (Option 5) summarised in Table 7–18 exceed its annualised cost. The annualised cost of the preferred option of **$0.55 million** (real, 2023) is exceeded by the benefits in 2025 (i.e., summer 2024-25).

Table 7–18: Optimum timing analysis of preferred option (real million, $2023)

Year	Base Case EUE and Losses	Option 5 Residual EUE and Losses	Benefit of Option 5
2024	0.34	0.00	0.0
2025	0.67	0.04	0.63
2026	0.91	0.04	0.87
2027	1.11	0.04	1.07
2028	1.33	0.04	1.29
2029	1.73	0.04	1.69
2030	2.50	0.05	2.46
2031	4.00	0.05	3.94
2032	6.99	0.06	6.93

The RIT-D options analysis concludes that:

- Option 5, to combine BTS-FF 184 and BTS-FF 188 and augment BTS-FF 22kV loop with a third 22 kV line (twin cable) is the preferred network option because it addresses the identified need and maximises the present value of net market benefits compared with all the other options;
- The optimum timing of the investment is to have the preferred network option in service by 1 November 2024 to align with the start of the 2024-25 summer peak demand period. However, given the lead time for project construction and commissioning, the completion of the preferred network option is by 1 November 2025; and
- There are no credible non-network options or combinations of non-network options with network options that could be used to defer the need for the preferred network option.

The preferred option (Option 5) was tested under a range of sensitivities including variations in costs, VCR and other base assumptions. In each case, Option 5 was confirmed to provide positive economic benefits, and is the highest-ranked option as shown in Table 7–19 below.

Table 7–19: Net Present Value (NPV) Economic Benefits sensitivities (real million, $2023)

Option	Higher Costs +30%	Lower VCR -10%	Lower Growth -20%	Higher Disc Rate +1%	Lower Costs -10%	Higher VCR +10%	Higher Growth +10%	Lower Disc Rate -1%
Option 1	n/a							
Option 2	17.02	19.20	18.91	19.11	26.05	28.41	26.00	29.62
Option 3	43.04	40.48	36.84	39.23	47.12	51.70	50.66	54.26
Option 4	44.64	42.17	38.49	40.85	49.27	54.03	52.92	56.72
Option 5	**45.72**	**43.03**	**39.16**	**41.69**	**50.09**	**54.94**	**53.84**	**57.68**

8. Conclusions and next steps

This section details the preferred option and next steps in the RIT-D consultation process.

8.1 Preferred option

In line with the assessment, the preferred option is Option 5, as this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. This solution will deliver a reliability-maintained outcome and is in the long-term interests of JEN's customers.

Option 5, to combine BTS-FF 184 and BTS-FF 188 and augment BTS-FF 22kV loop with a third 22 kV line (twin cable) includes the following works:

- parallel the sections of BTS-FF 184 and BTS-FF 188 that are in a common cable trench or on shared double circuit poles (3,500m in total), by relocating the existing BTS-FF 184 cable at BTS to the BTS-FF 188 CB, and connecting the two circuits at pole 31, to form a combined BTS-FF 188 feeder;
- reconductor the 750 m section of BTS-FF 188 undersized overhead line between FF and pole 31 with 37/3.75AAC to increase the summer rating of BTS-FF 188 to 700A (26.6 MVA);
- retire the existing 600 m section of BTS-FF 184 overhead conductor sharing the same poles as BTS-FF 181 from pole 78 to FF, and disconnect from the BTS-FF 184 incomer connection at FF; and
- supply and install approximately 4.1 km of new 2 x 3c 300mm^2 Al XLPE underground cable from BTS-FF 184 feeder CB at BTS, and connect to BTS-FF 184 incomer at FF.

The total capital cost of Option 5 is $10.58 million (real, 2023 including overheads) with an additional O&M expenditure of $0.1 million per annum (real, 2023).

8.2 Next steps

JEN invites written submissions on this report from Registered Participants, interested parties, AEMO and non-network solution providers. All submissions and enquiries should be directed to:

Email: PlanningRequest@jemena.com.au
Phone: (03) 9173 7000

Submissions should be lodged on or before 20 October 2023. All submissions will be published on JEN's website. Please indicate if you do not wish to have your submission (or parts of the submission) published.

Following our consideration of any submissions on this DPAR, we will proceed to prepare a FPAR. This report will include a summary of, and commentary on, any submissions to this report, and present the final preferred solution to address the identified need. Publishing the FPAR will be the final stage in the RIT-D process.

JEN intends to publish the FPAR by 30 October 2023. Note that if no submissions are received on this report, JEN will discharge its obligation to publish the FPAR, and instead include the final decision in the 2023 DAPR.