Jemena Electricity Networks (Vic) Ltd

Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation

RIT-D Stage 2: Draft Project Assessment Report

An appropriate citation for this paper is:

Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation

Authorisation

Name	Job Title	Date	Signature
Reviewed by:			
Tan Bui	Principle Engineer, Future Network & Planning	16/07/2021	Endorsed via email
Approved by:			
Karl Edwards	General Manager Asset Management – Electricity Distribution	19/07/2021	Endorsed via email

History

Rev No	Date	Description of changes	Author
1	15/07/2021	Initial Document	Hung Nguyen

Owning Functional Area

Business Function Owner:	Asset & Operations – Electricity | Jemena Networks

Review Details

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

Executive summary

Jemena Electricity Networks (Vic) Ltd (JEN) is the licensed electricity distributor operating in 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 an efficient possible cost. To do this, JEN must adopt the most efficient solution when investing in and maintaining the electricity distribution network. This means choosing the solution that maximises the net economic benefit—in present value terms—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 regulatory compliance in relation to its bushfire-start mitigation obligations at Coolaroo (COO) Zone Substation. The DPAR outlines how the risks for the Coolaroo supply area have been quantified, presents possible options for economically mitigating those risks, and identifies the preferred option to enable JEN to meet its compliance obligations for the area at least cost.

Identified need

The Coolaroo supply area, located in Melbourne's outer northern suburbs, encompasses the suburbs of Roxborough Park, Meadow Heights, Greenvale, Bulla, Mickleham and surrounds. The area is supplied by electricity distribution feeders operating at a voltage level of 22 kV, emanating from the 66 kV / 22 kV COO zone substation. COO has distribution feeders supplying into declared Hazardous Bushfire Risk Areas (HBRA).

Under the Victorian Electricity Safety Act 1998 (Act) and the Electricity Safety (Bushfire Mitigation) Regulations 2013 (Regulations), JEN is obliged to ensure that all 22 kV distribution feeders originating from COO meet specified technical performance requirements by 1 May 2023. The compliance obligations effectively require all COO feeders to be protected by Rapid Earth Fault Current Limiter (REFCL) technology or otherwise requiring these feeders to be the subject of exemptions under the Act and Regulations. The compliance obligations are driven entirely by bushfire-start mitigation needs.

In the process of assessing and identifying viable options to provide the most economic and technically feasible solution to maintain compliance with the Act and Regulations, JEN is also obliged to consider the:

- customer reliability impact (unserved energy) associated with the technical limitations of the REFCL technology;
- costs to High Voltage (HV) customers to upgrade their equipment (to enable them to continue to take supply safely from a REFCL protected feeder in accordance with Clause 16 (c) of the Victorian Electricity Distribution Code (VEDC); and
- long-term load growth of the impacted area and associated network augmentation requirements.

RIT-D process

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

The RIT-D applies in circumstances where an emerging 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. In November 2017, the Australian Energy Regulator (AER) introduced a new requirement that a RIT-

D should be undertaken that includes the publication of a non-network options report for those projects greater than $11 million[1] in value, where a non-network solution is potentially viable.

Options considered

After considering its compliance obligations for COO, JEN concluded the Coolaroo supply area is a priority area for bushfire-start mitigation investment, developing a Network Development Strategy[2] in response to help explore investment options. The strategy identifies a range of credible options to address bushfire-start risks in the Coolaroo supply area and are included for assessment in this RIT-D as follows:

- Option 1: Do Nothing;
- Option 2: Install Isolation Transformers on Underground Feeders and REFCLs at COO[3];
- Option 3: Install REFCLs at COO[4];
- Option 4: Two REFCL Zone Substations in JEN[5];
- Option 5: Build a New REFCL Zone Substation ('GVE')[6]; and
- Option 6: Install Two REFCLs at COO Under a Split Bus Configuration with One High-Performance REFCL[7].

As part of the RIT-D process, JEN considered the credibility of potential non-network options as alternatives to the network options above. A Non-Network Options Screening Report, published on JEN's website on 12 April 2021, was prepared to establish whether the currently proposed works could be changed in scope or otherwise altered, in response to a non-network solution. The Non-Network Options Screening Report was predicated on the need for a non-network option to address the bushfire-start risk that would otherwise have been addressed by REFCL technology. From the consultation on the Non-Network Options Screening Report, JEN did not receive any submissions which provided a viable non-network alternative solution.

Proposed preferred option

The RIT-D options analysis concludes that:

- Option 6, installing two REFCLs at COO under a split-bus configuration with one high-performance REFCL, is the preferred network option because it addresses the identified need and maximises the present value of net market benefits compared to all the other options;
- The optimum timing of the investment is to have the preferred network option in service by 1 May 2023; 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.

It should be noted that the preferred option (Option 6) was tested under a range of sensitivities, including variations in costs, Value of Customer Reliability (VCR) and other base assumptions. Option 6 was confirmed to provide positive economic benefits in each case and is the highest-ranked option.

[1] In accordance with the AER Final Application Guidelines RIT-D (14 December 2018), from 1 January 2019 to end of December 2021, the cost threshold is $11 million. Also see AER, Final determination: Cost thresholds review, November 2018, p.14.

[2] Refer to 2021-26 Electricity Distribution Price Review Revised Proposal Attachment 04-03 "Network Development Strategy - Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation", available from https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26/revised-proposal

[3] Option 7 within the Network Development Strategy referred to in footnote reference 2.

[4] Option 11 within the Network Development Strategy referred to in footnote reference 2.

[5] Option 15 within the Network Development Strategy referred to in footnote reference 2.

[6] Option 27 within the Network Development Strategy referred to in footnote reference 2.

[7] Option 28 within the Network Development Strategy referred to in footnote reference 2.

JEN intends to proceed with the preferred network option to meet its bushfire-start mitigation obligations at COO. The preferred option has a net market benefit of $39.7 million compared to the “Do Nothing” option as shown in Table ES-1.

Table ES–1: Summary of cost-benefit analysis for preferred option (real, million $2020)

Option	“Do Nothing” Option 1	“Preferred” Option 6
Network capital investment	-	(34.8)
HV customers capital investment	-	(9.1)
Additional O&M	-	(2.2)
Expected unserved energy (EUE)	(98.7)	(12.9)
Net Present Value of Benefits	**-**	**39.7**

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 2021 Distribution Annual Planning Report. If submissions are received on this report, JEN will publish a Final Project Assessment Report (FPAR).

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 on or before 3 September 2021.

All submissions will be published on JEN’s website. If you do not wish to have your submission (or parts of the submission) published, please indicate this clearly.

Following consideration of 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 1 October 2021. 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 2021 Distribution Annual Planning Report.

Table of contents

List of tables

List of figures

Glossary

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Constraint	Refers to a constraint on network power transfers that affects customer service.
Contingency condition (or event)	Refers to the loss or failure of part of the network. An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Contingency probability	The probability that a contingency condition (or event) will occur, and typically approximated by multiplying the number of times a contingency condition occurs (usually in a year) by its duration, normalised by the total available time (in this case, a year).
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 long-term, probability-weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for cost-benefit analysis, using the Value of Customer Reliability (VCR), which reflects the economic cost per unit of unserved energy.
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 northwest greater Melbourne.
Limitation	Refers to a limitation on a network asset's capacity 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.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also, million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network 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.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Non-network	Refers to anything potentially affecting the transfer of electricity to customers that do not involve the network.
Non-network alternative	A response to growing customer demand that does not involve network augmentation.
Operations & Maintenance expenditure (O&M)	Expenditure (ongoing) for running a product, business or system.
Peak or maximum demand	The highest amount of electrical power delivered (or forecast to be delivered) for a particular period.
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.
Probabilistic method	A planning methodology applied to network types with the most significant constraints and associated augmentation costs. It involves estimating the cost of a network limitation with consideration of the likelihood and severity of network outages and operating conditions.
Rapid Earth Fault Current Limiter (REFCL)	Rapid Earth Fault Current Limiter or REFCL means any plant, equipment or technology (excluding neutral earthing resistor) which is: a) designed to reduce the effect of distribution system faults and when operating as intended may lead to a REFCL condition; and b) approved by Energy Safe Victoria in an electricity safety management scheme or bushfire mitigation plan pursuant to the Electricity Safety Act 1998 (Vic).
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 corrective action	Reliability corrective action, as defined in the National Electricity Rules, means investment by a Transmission Network Service Provider or a Distribution Network Service Provider in respect of its transmission network or distribution network for the purpose of meeting 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.
Reliability of supply	The measure of the ability of the distribution system to supply to customers.

Required Capacity	As prescribed by the Electricity Safety (Bushfire Mitigation Duties) Regulations 2018, means that in the event of a phase-to-ground fault on a polyphase electric line, then the network must have the ability:
	• to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and
	• to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to:
	  • 1900 volts within 85 milliseconds; and
	  • 750 volts within 500 milliseconds; and
	  • 250 volts within 2 seconds; and
	• during diagnostic tests for high impedance faults, to limit:
	  • fault current to 0.5 amps or less; and
	  • the thermal energy on the electric line to a maximum I^2t value of 0.10;
	where:
	• high impedance faults means a resistance value in ohms that is equal to twice the nominal phase-to-ground network voltage in volts;
	• I^2t means a measure of the thermal energy associated with the current flow, where I is the current flow in amps and t is the duration of current flow in seconds;

	• low impedance faults means a resistance value in ohms that is equal to the nominal phase-to-ground network voltage in volts divided by 31.75; and • polyphase electric line means an electric line comprised of more than one phase of electricity with a nominal voltage between 1 kV and 22 kV.
REFCL condition	An operating condition on the 22kV distribution system arising from the proper operation of a REFCL which results in the neutral reference of the distribution system moving to allow the un-faulted phase-to-earth voltage magnitude to approach a value close to the phase-to-phase voltage magnitude. The term "operating condition on the 22kV distribution system" in this term extends up to, but not beyond, any device or plant which is functionally equivalent to an isolating transformer.
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 dollar 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

Act	Electricity Safety Act 1998
AER	Australian Energy Regulator
BD	Broadmeadows Zone Substation
BMS	Broadmeadows South Zone Substation
CB	Circuit Breaker
Co	Network capacitive current
COO	Coolaroo Zone Substation
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAPR	Distribution Annual Planning Report
DM	Demand Management
EG	Embedded Generation
ESV	Energy Safe Victoria
EUE	Expected Unserved Energy
GVE	Greenvale Zone Substation
HBRA	Hazardous Bushfire Risk Area
HV	High Voltage
JEN	Jemena Electricity Network
KLO	Kalkallo Zone Substation
kV	Kilo-Volts
LBRA	Low Bushfire Risk Area
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
O&M	Operations and Maintenance
PoE	Probability of Exceedance
REFCL	Rapid Earth Fault Current Limiters
Regulations	Electricity Safety (Bushfire Mitigation) Regulations 2013
RIT-D	Regulatory Investment Test for Distribution
SBY	Sunbury Zone Substation
ST	Somerton Zone Substation
VCR	Value of Customer Reliability
VEDC	Victorian Electricity Distribution Code

1. Introduction

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

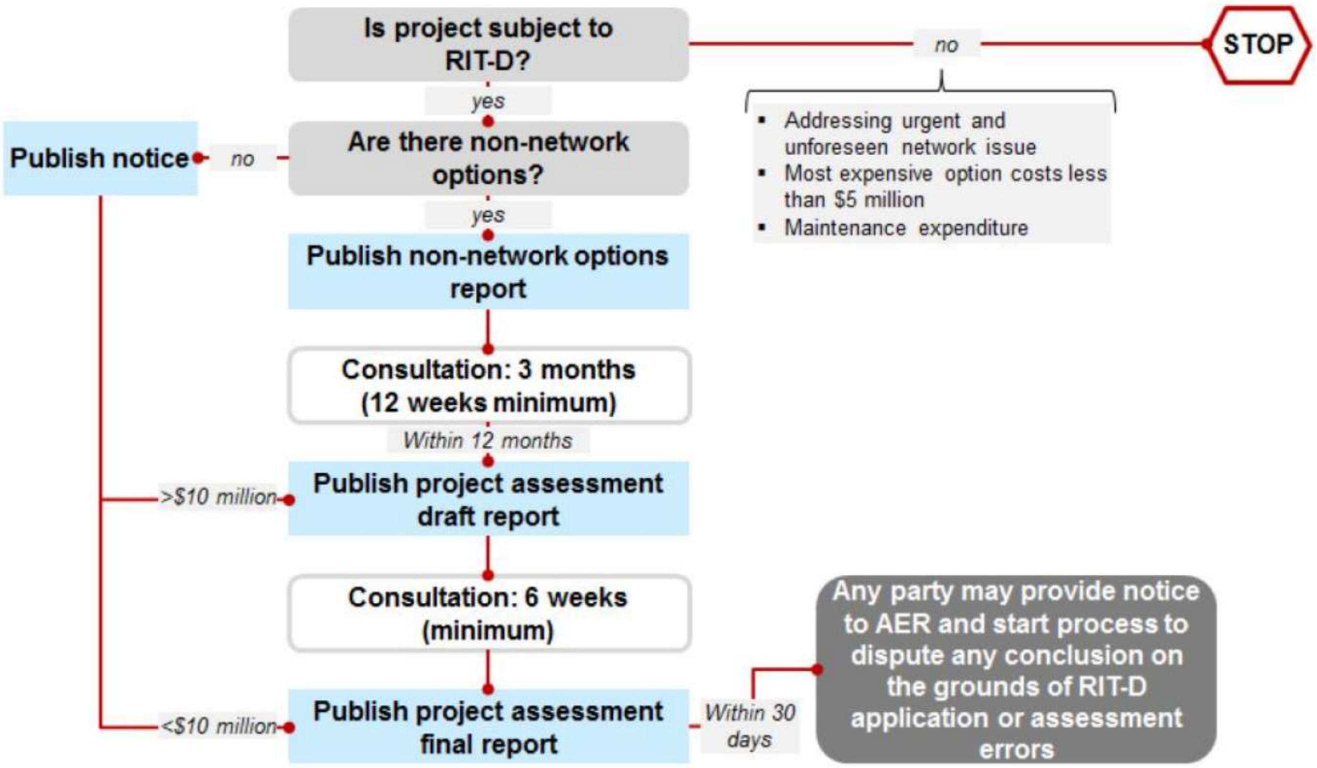
1.1 RIT-D purpose and process

Distribution businesses must conduct the RIT-D process to identify the investment option that best addresses an identified need on the network. That is, the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM (the preferred option).

The RIT-D applies when an emerging 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. In November 2017, the Australian Energy Regulator (AER) introduced a new requirement that a RIT-D should be undertaken that includes the publication of a non-network options report for those projects greater than $11 million[8] in value, where a non-network solution is potentially viable.

The RIT-D process is illustrated in Figure 1–1.

Figure 1–1: The RIT-D Process[9]



8 In accordance with the AER Final Application Guidelines RIT-D (14 December 2018), from 1 January 2019 to end of December 2021, this cost threshold is $11 million. Also see AER, Final determination: Cost thresholds review, November 2018, p.14.

9 Source: AER Final Application Guidelines RIT-D (14 December 2018) – Figure 1.

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 comply with its bushfire-start mitigation regulatory obligations at COO.

It follows on from our Non-Network Options Screening Report consultation and considers network, non-network and hybrid options based on that report.

This DAPR describes the:

- Coolaroo supply area and JEN's regulatory obligations at COO (Section 2);
- Identified need in relation to the Coolaroo supply area (Section 3);
- Potential for non-network options to address the identified need (Section 4);
- Credible network options assessed to address the identified need (Section 5);
- The method used to quantify market benefits (Section 6);
- Net present value assessment results for the potential credible options assessed (Section 7); and
- Technical characteristics of the proposed preferred credible option (Section 8).

2. Background

JEN has ownership and responsibility for managing the electricity distribution network supplying the Coolaroo supply area. This section provides an overview of JEN's regulatory obligation to mitigate bushfire-start risks within its distribution network and how these obligations apply to COO and the Coolaroo supply area more broadly.

2.1 Bushfire Mitigation Regulatory Obligations

JEN is obliged to comply with Section 120M of the Electricity Safety Act 1998 together with sub-regulation 7(1)(ha) of the Electricity Safety (Bushfire Mitigation) Regulations 2013. The compliance obligations are driven entirely by bushfire-start mitigation needs.

The Regulations require that each polyphase electric line originating from each prescribed zone substation must have the 'Required Capacity'[10], which includes the following capability in the event of a phase to a ground fault:

> *To reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to:*
>
> *i) 1900 volts within 85 milliseconds; and*
>
> *ii) 750 volts within 500 milliseconds; and*
>
> *iii) 250 volts within 2 seconds.*

The obligations also impose significant financial penalties if service performance in accordance with the timetable is not met. The Bushfire Mitigation Civil Penalties Scheme includes financial penalties of up to $2 million per point for any difference between the total number of required substation points prescribed in the Regulations and that actually achieved. The scheme also includes a daily penalty of up to $5,500 per point each day that a contravention with the Regulations continues.

Based on the bushfire risk rating of the Coolaroo supply area at the time the Regulations came into effect, COO has been designated as a one (1) point zone substation in the Electricity Safety (Bushfire Mitigation) Regulations 2013 (Schedule 2). According to the Regulations, JEN must be compliant at COO by 1 May 2023.

The compliance obligations effectively require the 22 kV distribution feeders emanating from COO to be protected by REFCL technology or otherwise requiring these feeders to be the subject of exemptions under the Act and Regulations.

In the process of assessing and identifying viable options to provide the most economic and technically feasible solution to maintain compliance with the Act and Regulations, JEN is also obliged to consider the

- customer reliability impact (unserved energy) associated with the technical limitations of the REFCL technology;
- costs to High Voltage (HV) customers to upgrade their equipment (to enable them to continue to take supply safely from a REFCL protected feeder in accordance with Clause 16 (c) of the VEDC); and
- long-term load growth and associated network augmentation requirements.

After considering these obligations, JEN has concluded the Coolaroo supply area is a priority area for bushfire-start mitigation investment.

[10] Other performance requirements are also specified in the definition of 'Required Capacity' in the Electricity Safety (Bushfire Mitigation) Regulations 2013.

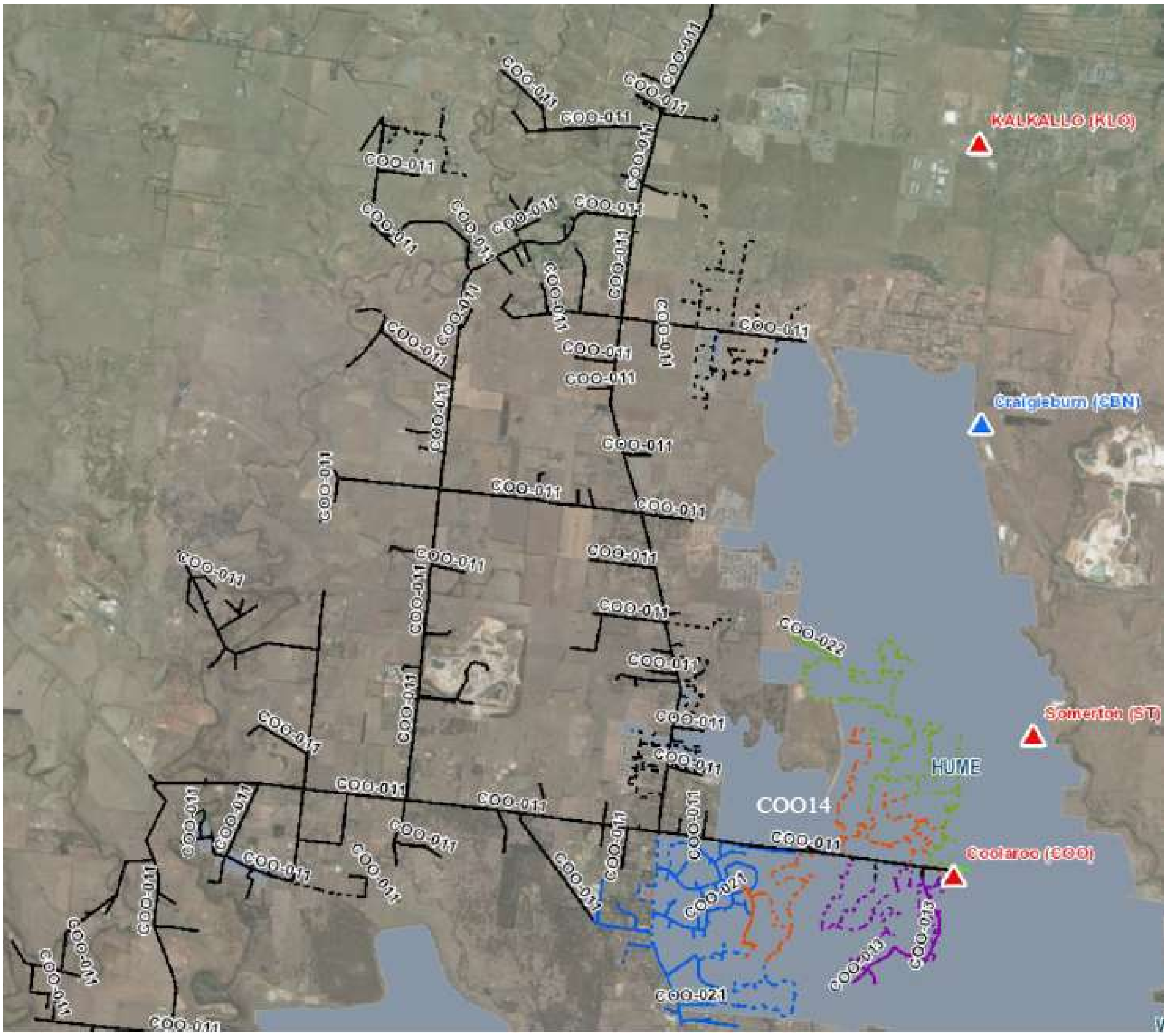
2.2 Coolaroo supply area

JEN is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The JEN service area covers 950 square kilometres of northwest greater Melbourne and includes some major transport routes and the Melbourne International Airport, which is located at the approximate physical centre of the service area. The network comprises over 6,900 kilometres of electricity distribution lines and cables, delivering approximately 4,400 GWh of energy to around 330,000 homes and businesses for a number of energy retailers. The network service area spans from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south, and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

The Coolaroo supply area within the JEN service area, located in Melbourne's outer northern suburbs, encompasses the suburbs of Roxborough Park, Meadow Heights, Greenvale, Bulla and Mickleham. The area is supplied by electricity distribution feeders operating at a voltage level of 22 kV, emanating from the two-transformer 66 kV / 22 kV COO zone substation. COO has six distribution feeders, one of which (COO-011) supplies into a declared HBRA.

Figure 2–1 shows the Coolaroo supply area and the COO 22kV distribution feeders.

Figure 2–1: Coolaroo Supply Area

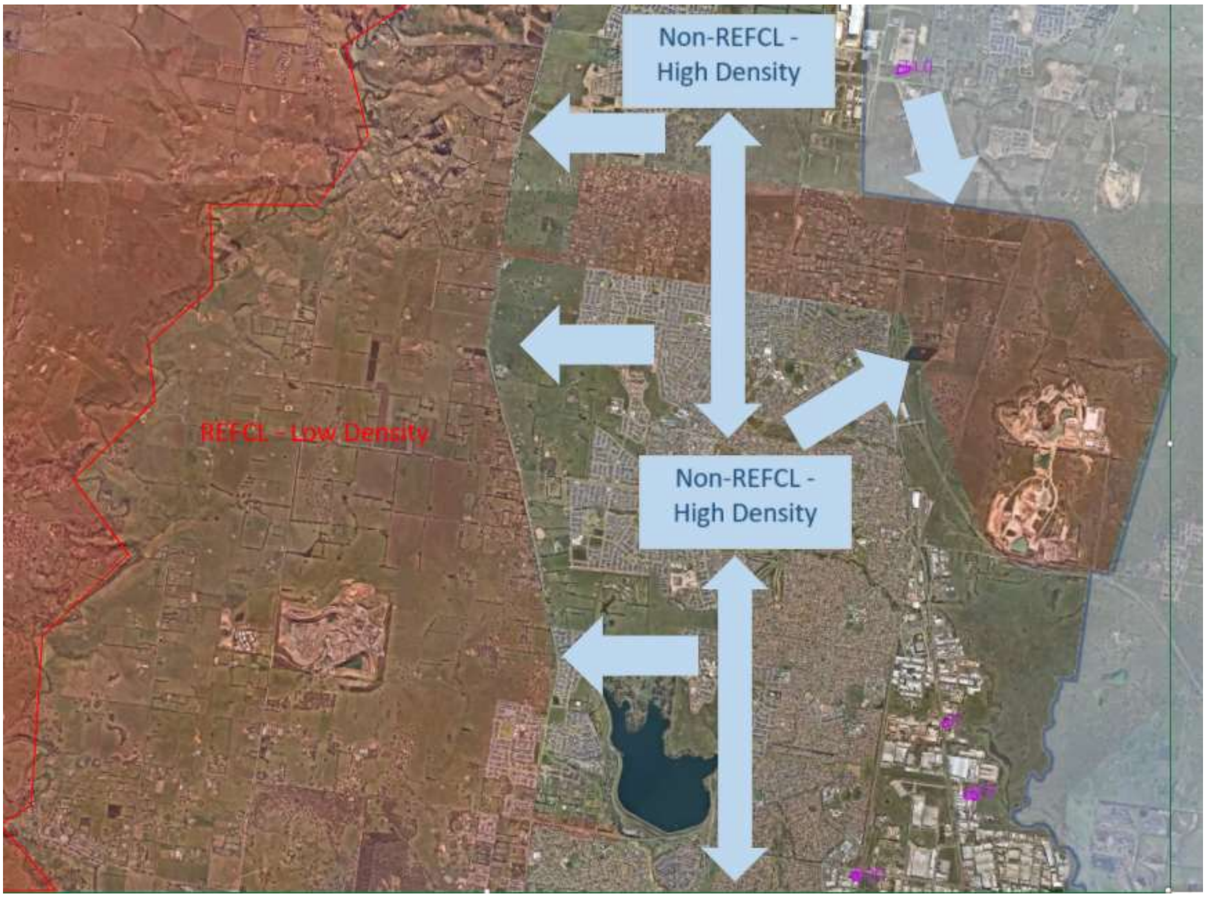


The network area fed by COO is a mix of underground and overhead feeders. The underground feeder areas are urban and are all within the Low Bushfire Risk Area, as depicted by the grey areas in Figure 2-2 below. COO11 represents the vast majority of the COO 22 kV network and has 36.7km of underground cable and 133.3km of overhead network, where COO 22 kV network totals are 99.8km and 156.7km respectively.

There are two HV customers within the COO LBRA, located on COO12 and BD14 (ex. COO13), and one in the COO HBRA, on COO 11. These customers or 'substation points' are still subject to the requirements of the Act and Regulations due to having been part of the COO network on the date as specified within the Act and Regulations.

COO is located in the North Growth Corridor[11] of Melbourne and supplies a mix of high density urban and low-density rural areas. The urban areas within the Coolaroo supply area supplied by COO, are expected to continue to grow towards the urban growth boundary. In contrast, the rural areas supplied by COO are expected to experience low levels of growth in the short to medium term. These differences are highlighted in Figure 2-2, where the high density non-REFCL areas are indicated as pushing out in the direction of the blue arrows.

Figure 2-2: Network Growth Opportunity



The Coolaroo supply area is bordered by non-REFCL zone substations Airport West (AW) and Broadmeadows (BD) to the south, Sunbury (SBY) to the west, Somerton (ST) to the east and AusNet's REFCL zone substation Kalkallo (KLO) to the north. Sections of the network may be transferred to adjacent zone substations temporarily during a planned or unplanned outage or permanently in response to load growth. A REFCL implementation must ensure all network assets are maintained within their safe loading limits and maintain the reliability of the network. Where existing transfers between REFCL and non-REFCL networks are no longer technically feasible due to installation of the REFCL[12], the probability and consequence of a supply outage must be assessed, and network augmentation or exemption may be required.

11 Refer to "Growth Corridor Plans – Managing Melbourne's Growth" available at https://vpa.vic.gov.au/greenfield/growth-corridor-plans/

12 For example, due to capacitive current limits or the requirement for network hardening and balancing.

3. Identified need

JEN has identified the Coolaroo supply area as a priority for investment based on the bushfire-start risk that COO's distribution feeders pose to parts of the supply area. COO has been designated in the Regulations as needing to be compliant by 1 May 2023.

3.1 First identified need - Bushfire-start mitigation regulatory compliance

The primary need is related to mitigating bushfire-start risks from JEN's electricity network assets for the public. JEN's approach to safety-based needs categorises the risk into three categories - intolerable, As-Far-As-Practicable (AFAP) and tolerable. The AFAP principle recommends risk reduction measures be implemented at least cost unless the cost, time, or trouble of the risk reduction measures is grossly disproportionate to the benefit gained from the reduced risk. Consistent with the AFAP principle, JEN proposes adopting a REFCL technology option for the Coolaroo supply area. The risk to the public arising from potential bushfire-starts is considered significant, and hence the benefits of the REFCL technology for the Coolaroo supply area, which substantially reduces this risk, would also be substantial.

Bushfires ignited by powerlines contributed to the devastating 2009 Victorian Black Saturday bushfires. In the ensuing Royal Commission, REFCLs have been demonstrated to prevent faulted 22 kV powerlines from starting fires. Subsequently, the Victorian Government has mandated REFCL protection of higher risk feeders through amendments to the Electricity Safety (Bushfire Mitigation) Regulations 2013.

The 2009 Victorian Bushfires Royal Commission (Royal Commission) investigated the causes and responses to the bushfires. In its July 2010 Final Report, the Royal Commission concluded that powerlines started five of the major fires that it investigated. The Royal Commission made 67 recommendations, of which eight (Recommendations 27 to 34) related to reducing the likelihood of powerlines starting catastrophic bushfires.

The Powerline Bushfire Safety Taskforce (PBST) was established in August 2010 to recommend to the Victorian Government how to maximise the value to Victorians from the Royal Commission recommendations. The PBST presented its final report to the Victorian Government on 30 September 2011. The Victorian Government accepted PBST's recommendations and, in December 2011, announced a package of initiatives. Among these initiatives was a rollout of REFCL technology in selected zone substations prone to bushfire-start risk, subject to further trials on a real network to confirm their effectiveness in reducing fire risk.

REFCLs can reduce the risk of bushfire-starts from distribution feeders which experience a phase-to-earth fault. They reduce the current in any one phase which experiences an earth fault. As the devices act in milliseconds, they are designed to reduce customer supply interruptions without the need for human intervention whilst reducing the risk of starting a fire.

The REFCL fire ignition test project initiated by the Department of State Development Business and Innovation (DSDBI) and conducted in 2014 confirmed that the REFCL technology reduces the fire ignition risk associated with bare-wire overhead power lines. Current regulations have mandated the installation of REFCL technology with prescribed earth fault protection sensitivity described as the 'Required Capacity' at selected zone substations supplying into areas with extreme fire risk consequences. The Regulations came into operation on 1 May 2016.

The Victorian Government also introduced significant financial penalties if service performance in accordance with the timetable is not met. The Bushfire Mitigation Civil Penalties Scheme includes financial penalties of up to $2 million per point for any difference between the total number of required substation points prescribed in the Regulations and that actually achieved. The scheme also includes a daily penalty of up to $5,500 per point for each day that a contravention with the Regulations continues.

Provision has been made in the Act and Regulations for distributors to seek exemptions for sections of the network. Applying for exemptions is only feasible where bushfire ignition risk can be neutral compared to REFCL protection of these sections (e.g. underground cables or other forms of bushfire mitigation). The cost of compliance is high.

JEN is obliged to comply with Section 120M of the Electricity Safety Act 1998 together with sub-regulation 7(1)(ha) of the Electricity Safety (Bushfire Mitigation) Regulations 2013 for COO by 1 May 2023. COO has been allocated one (1) point in Schedule 2 of the Regulations.

3.2 Second identified need - Reliability of supply

In line with the purpose of the RIT-D, as outlined in Clause 5.17.1 (b) of the National Electricity Rules (NER), the identified need to address the COO compliance issue is an increase in the sum of customer and producer surplus in the NEM; that is an increase in the net economic benefit. This net economic benefits increase is realised through the second identified need to reduce the cost of Expected Unserved Energy (EUE) (predominantly by a change in the amount of involuntary load shedding in this case), and balancing this benefit against each development option's cost, to identify the optimal solution and timing.

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

- Directly measures customer (economic) outcomes associated with future network limitations;
- Provides a thorough cost-benefit analysis when evaluating network or non-network augmentation options; and,
- Estimates EUE, which is defined in terms of megawatt hours (MWh) per annum, and expresses this economically by applying a VCR ($/MWh).

JEN uses this approach to identify, quantify and prioritise investment in the distribution asset. Typically, the EUE is calculated by understanding the load-at-risk for each zone substation, the difference between the demand and the asset capacity rating. This is usually calculated through modelling load-at-risk under system normal condition and if any single item of equipment was out of service (called a normal minus one or N-1 scenario). A credible non-network solution should maintain a level of supply reliability that is consistent with regulatory obligations. Hence, the minimum capacity of a solution would be the capacity to supply all load under an N and N-1 network reliability scenario, in which the annualised cost of EUE exceeds the annualised cost of the investment.

In accordance with clause 5.17.1(b) of the NER, JEN's investment decisions aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM. To achieve this objective, JEN applies a probabilistic planning methodology that considers the likelihood and severity of critical network conditions and outages using asset failure rates and restoration times. The method compares the forecast cost to consumers of losing supply (e.g., when there is a feeder outage and it can't be transferred to an adjacent feeder due to the REFCL technical limitations) against the proposed investment cost to mitigate the supply reliability risk. The annual cost to consumers is calculated by multiplying the EUE (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the VCR. The present value of this expected benefit is then compared with the costs of the feasible options.

The complexities and technical limitations associated with REFCL equipment can introduce several constraints during network operations—for example, limiting the ability to undertake emergency load transfers between feeders may lead to significant supply interruptions under some circumstances. Each option considered, including "Do nothing" have different reliability outcomes. This provides an opportunity to realise market benefits. In essence, the total cost for each option includes the following:

- Project cost to comply with the Act and Regulations by 1 May 2023;
- Annual ongoing operating and maintenance expenditure (O&M) to maintain compliance;
- HV customer costs to comply with the Act and Regulations by 1 May 2023; and
- Present value of the cost of EUE.

The impacts of load growth are factored into the annual cost of EUE considered in the analysis.

3.3 Credible solution requirements

Credible solutions are required under the Regulations to provide the 'Required Capacity' meaning that, in the event of a phase-to-ground fault on a polyphase electric line, the network must have the ability:

- to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for high impedance faults to 250 volts within 2 seconds; and
- to reduce the voltage on the faulted conductor in relation to the station earth when measured at the corresponding zone substation for low impedance faults to:
  - 1900 volts within 85 milliseconds; and
  - 750 volts within 500 milliseconds; and
  - 250 volts within 2 seconds; and
- during diagnostic tests for high impedance faults, to limit:
  - fault current to 0.5 amps or less; and
  - the thermal energy on the electric line to a maximum I^2t value of 0.10;

where:

- high impedance faults means a resistance value in ohms that is equal to twice the nominal phase-to-ground network voltage in volts;
- I^2t means a measure of the thermal energy associated with the current flow, where I is the current flow in amps and t is the duration of current flow in seconds;
- low impedance faults means a resistance value in ohms that is equal to the nominal phase-to-ground network voltage in volts divided by 31.75; and
- polyphase electric line means an electric line comprised of more than one phase of electricity with a nominal voltage between 1 kV and 22 kV.

In practical terms, generally, these performance requirements can only be achieved through the installation of REFCL technology. REFCLs consists of four main components; an Arc Suppression Coil, Residual Current Compensator, Grid Balancing Unit and Control System.

In addition, the following works are required on the 22 kV feeders:

- feeder augmentation/reconfiguration to maintain each REFCL within its capacitive current limit, i.e., a maximum of 80A per 22 kV feeder, 100A per bus and 200A per zone substation, and to maintain the reliability of supply to homes and businesses;
- network capacitive balancing of single-phase (two-wire) spurs to facilitate correct REFCL operation, which includes installations of capacitor banks, third phase wires and re-phasing of some sections;
- line hardening to withstand the increased voltages on the non-faulted phases during REFCL operation, which includes the replacement of surge arrestors and some sections of underground cable with higher rated equipment; and
- replacement of some network equipment to be compatible with REFCL protected networks, including automatic circuit reclosers (ACRs), voltage regulators and sectionalisers.

In addition to achieving the 'Required Capacity', the following must also be taken into consideration:

- The level of reliability in the supply area must be maintained and managed in light of the REFCL technical limitations;

- Long-term load growth must be considered and catered for. In essence, the proposed solution needs to align with the network growth strategy;
- Lifecycle cost, including both the upfront cost of compliance and the ongoing cost of maintaining and operating the network; and
- The cost to HV customers of hardening their installations to withstand the increased voltages during REFCL operation in accordance with Clause 16(c)[13] of VEDC.

In the case of the Coolaroo supply area, the Regulations require each polyphase electric line originating from COO to comply with the performance standards specified in the Regulations by 1 May 2023. In response, JEN developed a Network Development Strategy[14] to identify options to address the identified need to comply with bushfire-start mitigation obligations at COO. As an output from the strategy, several options were identified to achieve the ‘Required Capacity’.

The network options to comply with bushfire-start mitigation obligations at COO could be changed in scope or otherwise altered in response to a viable non-network solution. JEN investigated and tested whether viable non-network solutions exist by publishing a Non-Network Options Screening Report and requested stakeholder submissions. No submissions with a viable non-network alternative solution were received. The network-specific nature of this performance standard is such that it cannot be practically met by a non-network option, such as an embedded generator or demand-side response, unless the network itself can be switched off. The use of REFCL technology is the only technically feasible solution currently available that can satisfy the performance requirements specified in the Regulations.

13 Clause 16 (c) of VEDC states that “*A **business customer** must take reasonable precautions to minimise the risk of loss or damage to any equipment, premises or business of the **business customer** which may result from poor quality or reliability of electricity **supply** or the **distribution system** operating under the **REFCL condition** in accordance with clause 4.2.2A*”

14 Refer to 2021-26 Electricity Distribution Price Review Revised Proposal Attachment 04-03 “Network Development Strategy - Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation”, available from https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26/revised-proposal

4. Screening for non-network options

Potential non-network options that could meet the project objectives (as envisaged in the AER RIT-D Application Guidelines Section 6.1) were considered based on two alternatives - Generation/Storage and Demand Management. The National Electricity Rules requires RIT-D project proponents to investigate whether a non-network option (or combination of non-network measures) can avoid the need for investment in a network solution or at least allow 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 comply with the Regulations and achieve the 'Required Capacity' for COO.

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

The Non-Network Options Screening Report for complying with bushfire mitigation obligations at COO 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

A non-network option would need to address the bushfire-start risk that would otherwise have been addressed by REFCL technology. The Non-Network Options Screening Report published on JEN's website concluded that it was unlikely that a non-network solution could (either on its own or in combination with a network solution) provide a viable alternative. JEN did not receive any submissions on the Non-Network Options Screening Report that proposed a viable non-network alternative solution.

JEN has determined that no non-network option is potentially credible or that it forms a significant part of a potential credible option to address the identified need.

The reasons for this determination are:

1. The network-specific nature of this regulatory performance standard is such that a non-network option cannot meet it unless the network is switched off and all customers connected to the network have standby, standalone power supplies to avoid the interruption;
2. The proposed capital works on JEN's electricity distribution network is required to ensure that REFCL operation does not compromise the safety and reliability of the network; and
3. As the preferred network option addresses the impact of REFCL operation on JEN's distribution network and its service performance, non-network solutions cannot provide an effective substitute for the preferred network option.

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

5. Network options considered in this RIT-D

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

Recognising the interrelationships between adjacent zone substations COO and KLO, in 2019 JEN and AusNet Services engaged the consultant WSP to assist in a joint planning exercise to examine several technical design options and determine the most efficient cost of meeting the requirements of the Act and Regulations across both COO and KLO supply areas over the long-term. This exercise identified 26 options.

JEN developed a Network Development Strategy[15] to shortlist the 26 options down to the most credible options to address bushfire-start risk in the Coolaroo supply area. This RIT-T examines these shortlisted options from the strategy as follows:

- Option 1: Do Nothing;
- Option 2: Install Isolation Transformers on Underground Feeders and REFCLs at COO;
- Option 3: Install REFCLs at COO;
- Option 4: Two REFCL Zone Substations in JEN;
- Option 5: Build a New REFCL Zone Substation (‘GVE’); and
- Option 6: Install Two REFCLs at COO Under a Split Bus Configuration with One High-Performance REFCL.

The option to have a simple REFCL installation at COO without network rearrangement is not possible due to the inherent technical limitations of REFCLs, including:

- A limit of only one Arc Suppression Coil (ASC) per 22 kV bus;
- A limit of 100A of network capacitive current (Co) per ASC due to network damping ratios. This means that the Co for each 22 kV bus must not exceed 100A;
- A limit of 80A Co per 22 kV feeder; and
- A limit of two REFCLs per zone substation (i.e., maximum zone substation Co of 200A).

COO is a two-transformer zone substation with six feeders; the network capacitance (Co) of each is tabulated in Table 5-1.

Table 5-1: Co of COO Zone Substation 22 kV feeders

Feeder	Co (A)	Underground (km)	Overhead (km)	Comments
COO-11	105	36.7	133.3	Exceeds maximum feeder Co of 80A.
COO-12	2	0.5	0.3	
COO-13	52	11.4	3.9	
COO-14	51	16.5	1.4	
COO-21	45	13.5	17.1	
COO-22	65	21.2	0.7	Heavily loaded
TOTAL	**320**	**99.8**	**156.7**	

[15] Refer to 2021-26 Electricity Distribution Price Review Revised Proposal Attachment 04-03 “Network Development Strategy - Comply with Bushfire Mitigation Obligations at Coolaroo Zone Substation”, available from https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26/revised-proposal

It is clear from Table 5-1 that the existing 320A of Co cannot be accommodated with a simple configuration of two REFCLs at COO zone substation without some form of network rearrangement and significant augmentation. Furthermore, the COO supply area forms part of the Melbourne northern growth corridor, and network Co is forecast to increase to 410A by 2029 due to network growth, further exacerbating the high Co issue.

5.1 Option 1: “Do Nothing” (Base Case)

The assessment of credible options is based on a cost-benefit analysis that considers the forecast EUE of each credible option compared with the Base Case, where no option is implemented. A “Do Nothing” option is explored in this report simply for comparison to assess the other options. Not delivering against the requirement—as suggestions under option 1—is not feasible because it is a legal requirement to do so.

Under this Base Case, the action required to ensure that the ‘Required Capacity’ is achieved is by involuntary load shedding of JEN’s customers. The cost of involuntary load shedding is calculated using the VCR.

The Base Case option gives the basis for comparing the cost-benefit assessment of each credible augmentation 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.

Since there is no capital cost associated with the Base Case (“Do Nothing”) option, this option is assumed to have zero benefits.

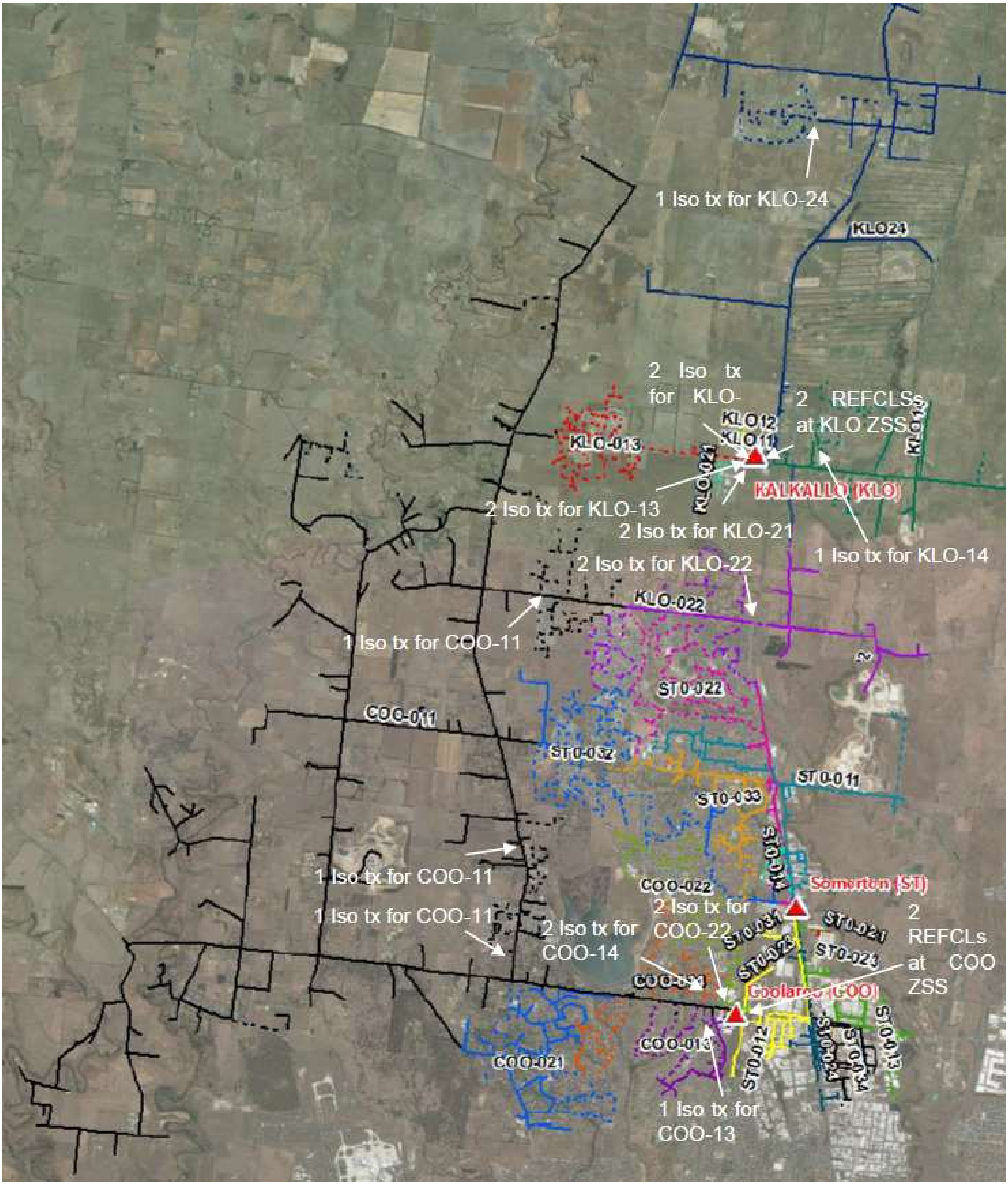
5.2 Option 2: Install Isolation Transformers on Underground Feeders and REFCLs at COO

This option involves segregating the underground network at COO (which is not contributing to bushfire-start risk) from the overhead components which are subject to the “Required Capacity”. This option is technically feasible and entails installing isolation transformers on underground feeders (to isolate them from the operation of the REFCL, allowing the REFCL costs to be reduced) and installing REFCLs at the COO zone substation to provide protection on the COO overhead network.

This option aims to provide REFCL protection for all overhead conductors and seeks exemption for all underground cables, particularly for the sections underground cables that are isolated.

Figure 5-1 provides a high-level diagrammatic overview of the scope of works.

Figure 5-1: Option 2 - High Level Scope of Works



The high-level scope of works required by JEN are:

- Install 2 REFCLs at COO zone substation, including network hardening and balancing
- For COO-11 feeder:
  - Underground 1.8km of overhead line on Mt Ridley Road
  - Install one isolation transformer, five kiosks and one Ring Main Unit on Mt Ridley Road

  - Install 370m of 22 kV cable
  - Install two isolation transformers at the start of the underground section on Mickleham Road
- For COO-13 feeder:
  - Install 2 x 170m 22 kV cable and one Ring Main Unit
  - Install one isolation transformer at the start of an underground section of the feeder
- For COO-14 feeder:
  - Transfer 1.4km of overhead conductor on COO-14 to COO-21
  - Install two isolation transformers at the start of an underground section of the feeder
  - Transfer the entire feeder to spare COO-23 CB to balance the capacitance on the COO zone substation bus so that the REFCL constraint limits are maintained
- For COO-22 feeder:
  - Underground 0.7km of overhead conductor
  - Install 2 kiosks
  - Install two isolation transformers at the start of the feeder
- Seek exemptions under the Act and Regulations for all isolated underground cables.

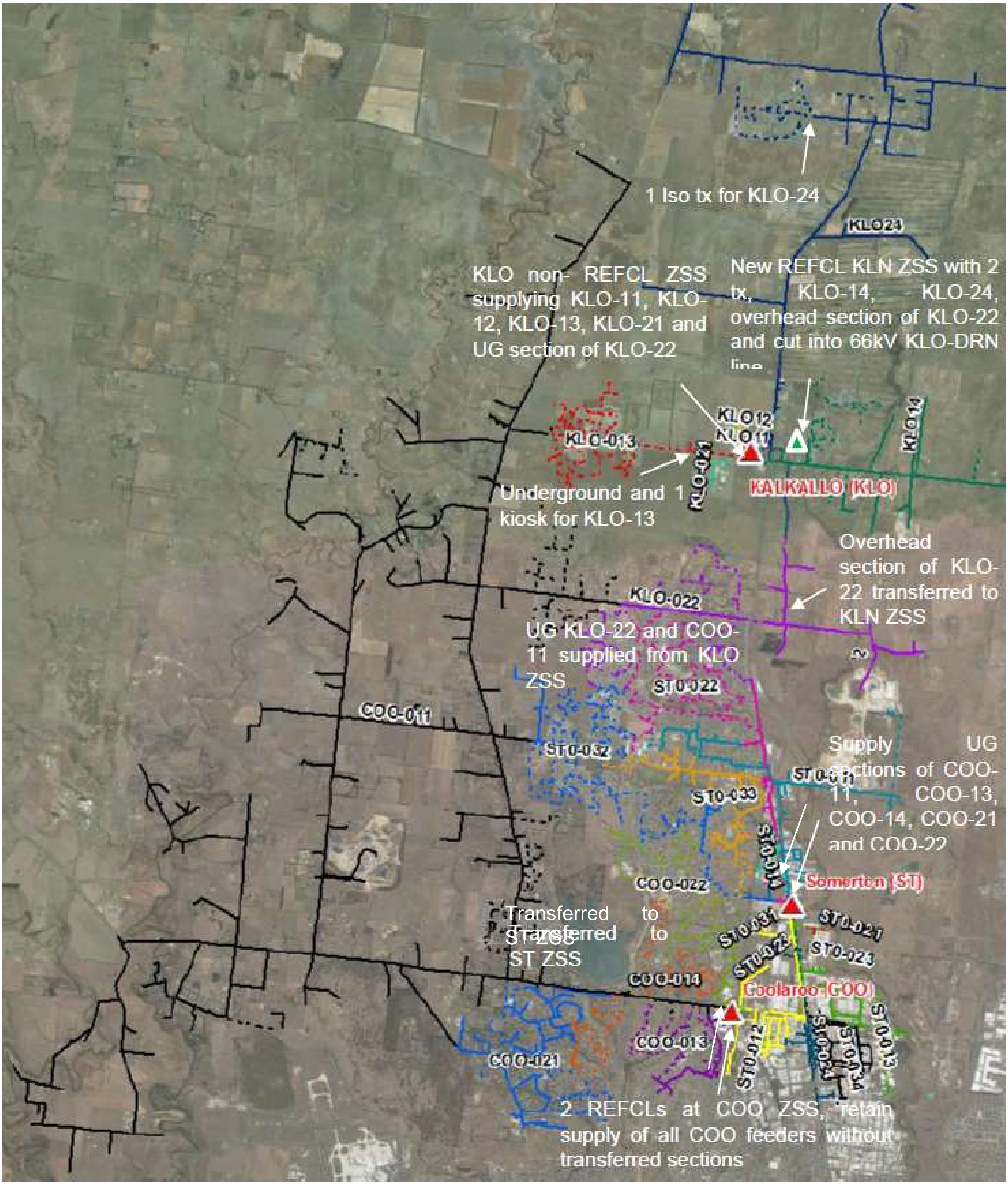
The total capital cost of Option 2 is $27.1 million ($2020), with an additional O&M expenditure for REFCL compliance testing of $0.31 million per annum. The total cost for HV customers in the Coolaroo supply area to comply with the Regulations is $9.3 million.

5.3 Option 3: Install REFCLs at COO

This option is technically feasible and entails installing REFCLs at COO and transferring its underground 22 kV feeders from COO to the adjacent zone substation ST. This option aims to provide REFCL protection for all overhead conductors and seek exemption for all underground cables.

Figure 5-2 provides a high-level diagrammatic overview of this option.

Figure 5-2: Option 3 - High Level Scope of Works



The high-level scope of works required by JEN are:

- 1.06km of new 22 kV cables to connect underground sections of COO-11 on Mt Ridley Road to KLO-22 and one Ring Main Unit. This will transfer the supply of this underground section from COO to KLO and will assist COO in meeting REFCL compliance by reducing the capacitance at the zone substation
- Install 2 REFCLs at COO, including network hardening and balancing
- Transfer underground sections of COO-11, COO-13, COO-14, COO-21 and COO-22 to ST zone substation

- Seek exemptions under the Act and Regulations for the COO feeders transferred to ST on the basis that they are all underground cables

The total capital cost of Option 3 is $24.7 million ($2020), with an additional O&M expenditure for REFCL compliance testing of $0.31 million per annum. The total cost for HV customers in the Coolaroo supply area to comply with the Regulations is $9.3 million.

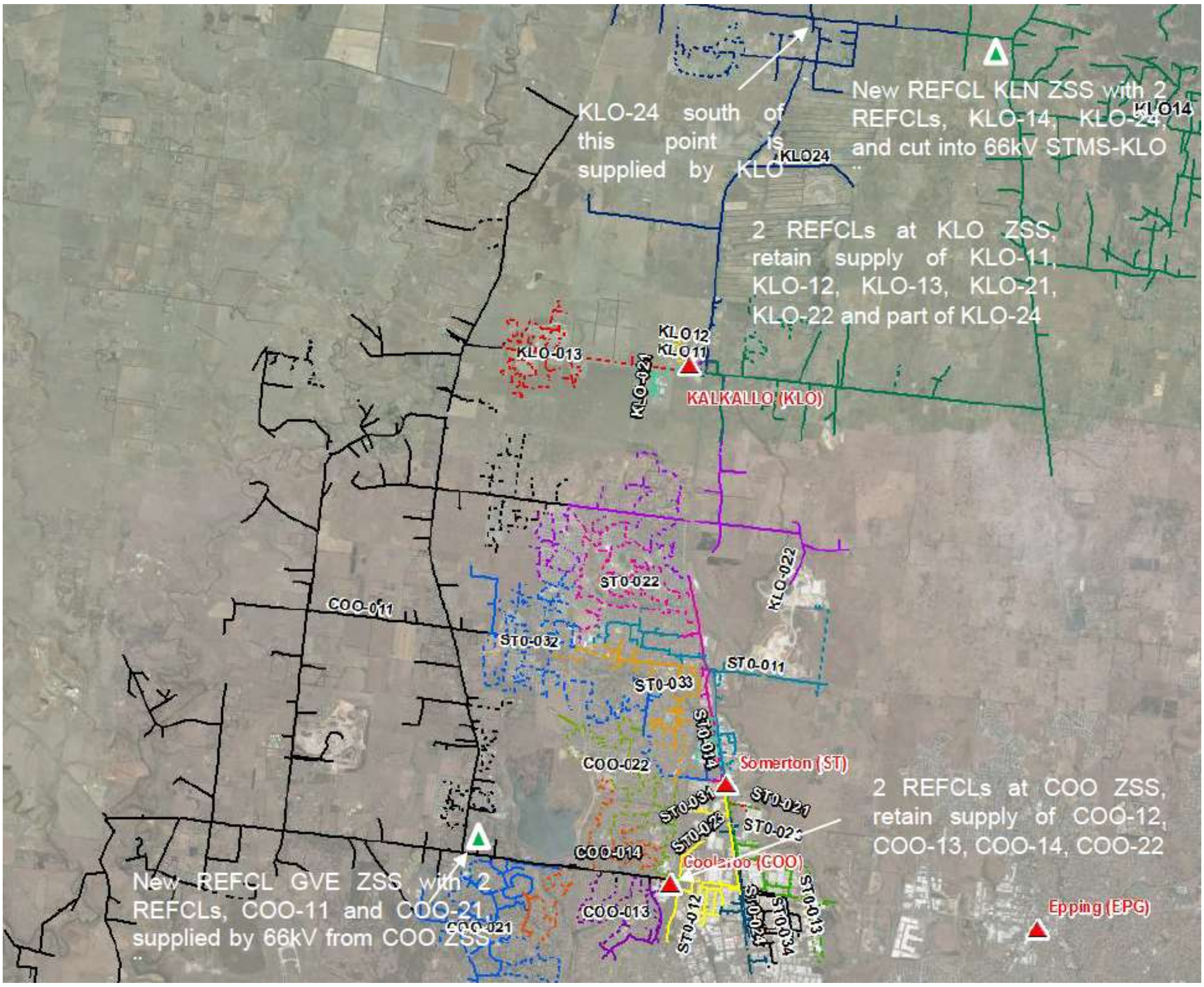
5.4 Option 4: Two REFCL Zone Substations in JEN

This option is technically feasible and does not require any exemption to the Act and Regulations. It entails two REFCL Zone Substations, COO and a new Greenvale Zone Substation ('GVE') to be built in the Greenvale area within JEN's supply area.

This option aims to provide REFCL protection for all overhead conductors and underground cables and accommodates growth in the underground cable network.

Figure 5-3 provides a high-level diagrammatic overview of this option.

Figure 5-3: Option 4 - High Level Scope of Works



The high-level scope of works required by JEN are:

1 GVE REFCL zone substation scope of works

- Build a new REFCL GVE zone substation with two transformers and 2 REFCLs which will supply COO-11 and COO-21
- New 10km of 66 kV overhead lines to supply GVE zone substation from COO
- Short sections of 22 kV underground cable and overhead line to connect COO-11 and COO-21 to GVE zone substation

2 COO REFCL zone substation scope of works

- Install 2 REFCLs at existing COO, including network hardening and balancing
- COO retains supply to COO-12, COO-13, COO-14 and COO-22
- Transfer 4km of underground cable from COO-14 to COO-22 to balance Co on both COO 22 kV buses within the 100A Co bus limit

The total capital cost of Option 4 is $51.9 million ($2020), with an additional O&M expenditure for REFCL compliance testing of $0.31 million per annum. The total cost for HV customers in the Coolaroo supply area to comply with the Regulations is $9.3 million.

Through the joint JEN and AusNet Services planning process, JEN identified that this was the only option that did not require any exemptions from the requirements of the Act and Regulations. However, this option involved significantly higher expenditure than other options due to significant technical limitations of the REFCL technology. For this reason, JEN investigated alternative solutions to the installation of a REFCL at COO and proposed an approach that will result in a level of residual bushfire-start risk that it considers is commensurate with that which the Act and Regulations originally intended, but at a lower cost to customers than if no exemptions to the Act or Regulations were granted. We considered that such alternative options would likely be more preferable in customers' long-term interests than this option.

5.5 Option 5: Build a New REFCL Zone Substation ('GVE')

Based on the outputs of the joint planning report[16] prepared by the engineering consultant WSP in December 2019 (and published as part of JEN's regulatory proposal on 31 January 2020), and further works undertaken by JEN since then, JEN identified this option to build a New REFCL Zone Substation ('GVE'), as the preferred option in its initial Network Development Strategy prepared in late November 2020.

This option aims to:

- provide REFCL protection for all overhead conductors and some underground cables in the HBRA from the new GVE zone substation; and
- seek exemption for all underground cables and overhead conductors within an urban environment supplied by COO (as a non-REFCL zone substation) and undertake various bushfire-start mitigation activities for the remaining overhead conductors (supplied by COO) that pose some risk to a fire ignition that could propagate to a bushfire.

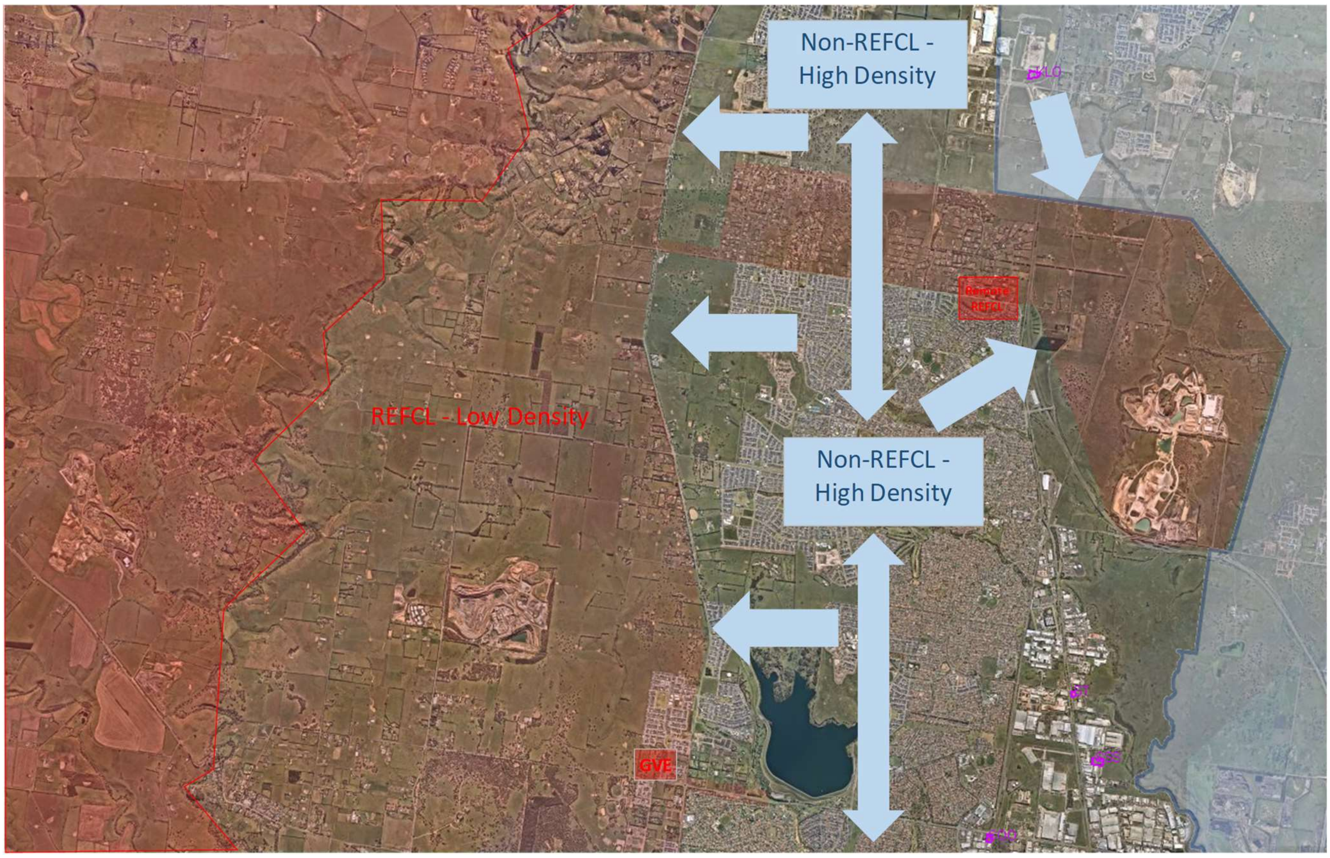
By separating the current COO supply area into a low-density rural area (or HBRA) to be REFCL protected and a high-density area within an urban environment to be a non-REFCL network, the capacity of COO can be fully utilised and integrated with its neighbouring ST and BD zone substations – the reverse also applies. This arrangement would allow JEN to avoid a decrease in network reliability levels for customers in the COO and neighbouring ST and BD supply areas.

[16] Refer to "Economic Options to Maintain REFCL Compliance at Kalkallo and Coolaroo Zone Substations, Joint Planning Report, December 2019" report.

This solution provides a bushfire risk-neutral outcome when compared to the installation of REFCL protection at COO. JEN lodged its exemption applications in May 2020 to both the ESV and DELWP for this solution at COO, and the exemptions from the Act and the Regulations were granted in November 2020.

Figure 5-4 provides a high-level geographic overview of this option.

Figure 5-4: Option 5 - Proposed 'GVE' Zone Substation



This option includes the following works:

- Construct a new zone substation with REFCL capability in the Greenvale area and transfer those sections of the existing COO 22 kV network with high bushfire-start risk, mainly COO-11, to the new zone substation – thereby providing REFCL protection to those 22 kV feeders in compliance with the Act and the Regulations, and
- Engage CSIRO to assess the bushfire-start risk associated with those sections of the COO 22 kV feeder network that will remain supplied by COO (as a non-REFCL zone substation) and obtain exemptions from the Act and Regulations for these network sections on the basis that:
    - For those polyphase electric lines (or parts thereof) of an underground construction, which pose an insignificant bushfire-start risk, the implementation of REFCL protection would not reduce the bushfire-start risk associated with these lines – and therefore, not implementing REFCL protection for these lines represents a bushfire risk-neutral outcome;
    - For those polyphase electric lines of an overhead construction within an urban environment that, following expert assessment by CSIRO, poses no risk of a fire ignition that could propagate to a bushfire – that not implementing REFCL protection for these lines represents a bushfire risk-neutral outcome; and
    - For those polyphase electric lines of an overhead construction that pose some risk to a fire ignition that could propagate to a bushfire, JEN would undertake various alternative bushfire mitigation activities to reduce this risk – resulting in a bushfire risk-neutral outcome.

JEN progressed the actions necessary to procure the land required for a new zone substation in the Greenvale area. However, the sale of land negotiations has stalled, and the procurement is now unlikely to be completed within a timeframe that would allow JEN to comply with the Act and Regulations by 1 May 2023. For this reason, JEN considers this option to be no longer technically feasible. JEN has therefore developed an alternative solution (the next Option 6) involving a conceptually similar REFCL solution, network layout and strategy and associated mitigation works while avoiding the need to procure land in the Greenvale area.

The total capital cost of Option 5 is $36.9 million ($2020), with an additional O&M expenditure for REFCL compliance testing of $0.31 million per annum. The total cost for HV customers in the Coolaroo supply area to comply with the Regulations is $1.3 million.

5.6 Option 6: Install Two REFCLs at COO Under a Split Bus Configuration with One High Performance REFCL

This option proposes installing two REFCLs at COO under a split-bus configuration, with one of the REFCLs being high performance to meet the 'Required Capacity'. This option aims to:

- provide high performance REFCL protection for all overhead conductors and some underground cables in the HBRA from COO Transformer No.1; and
- seek exemption for all underground cables and overhead conductors within an urban environment supplied by COO Transformer No.2 (as a base performance REFCL) or BD zone substation (as a non-REFCL network), and undertake various bushfire-start mitigation activities for the remaining overhead conductors (supplied by COO Transformer No.2 or BD zone substation) that pose some risk to a fire ignition that could propagate to a bushfire.

By separating the current COO supply area into a low-density rural area (incorporating the HBRA) to be high-performance-REFCL protected and a high-density area within an urban environment to be a base-performance-REFCL or non-REFCL network, the capacity of COO can be fully utilised and be integrated with its neighbouring ST and BD zone substations – the reverse also applies. This arrangement would allow JEN to minimise any decrease in network reliability levels for customers in the COO and neighbouring ST and BD supply areas.

This option is technically feasible and includes the following works:

- Install two REFCLs at COO under a split bus configuration—that is, one REFCL on COO Transformer No.1 with high performance settings to meet the 'Required Capacity', and one REFCL on COO Transformer No.2 with base performance settings which will be operated below the 'Required Capacity', with the 22kV bus-tie CB normally open. This arrangement will ensure the station will operate correctly by reducing the earth fault current on the COO Transformer No.2 side to a sufficiently low level that will avoid inadvertent tripping of COO Transformer No.1 side;
- Transfer those sections of the existing COO 22kV network with high bushfire-start risk, mainly COO-011, to COO Transformer No.1 (high performance REFCL)—thereby providing REFCL protection to those 22 kV feeders in compliance with the Act and the Regulations. The remaining sections of COO supply area will be transferred to COO Transformer No. 2 (base performance REFCL) and neighbouring non-REFCL BD zone substation to reduce the capacitance level to within acceptable design level on the base performance REFCL; and
- Undertake various bushfire-start mitigation activities to reduce the bushfire-start risk for those polyphase electric lines of an overhead construction within an urban environment that pose some risk to a fire ignition that could propagate to a bushfire—therefore resulting in a bushfire risk-neutral outcome—and obtain exemptions under the Act and Regulations in respect of these lines.

This solution provides a bushfire risk-neutral outcome when compared to the installation of REFCL protection at COO under Option 4.

JEN had previously lodged exemption applications in May 2020 to both the ESV and DELWP based on the Option 5 solution. Subsequently, the exemptions from the Act and the Regulations were granted in November 2020, with associated conditions requiring mitigation works to be undertaken. Following discussions with ESV in December 2020, it is likely that the granted exemptions published in the Government Gazette remain valid for this proposed Option 6 as this solution involves a conceptually similar REFCL solution, network layout and strategy and associated mitigation works to Option 5. JEN is currently working with ESV to confirm this position.

This option also facilitates JEN's general network growth strategy for the area.

The total capital cost of Option 6 is $36.5 million[17] ($2020), with an additional O&M expenditure for REFCL compliance testing of $0.31 million per annum. The total cost for HV customers in the Coolaroo supply area to comply with the Regulations is $9.3 million.

[17] Project cost for option 6 is $36.9M (real, $2021).

6. Market benefit assessment method

This section outlines JEN's method 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 outline 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, therefore, quantified.

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

- Involuntary load shedding and customer interruptions only.

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 maintaining network loading within asset capabilities. A credible option, either a network or non-network solution, aims to reduce the amount of involuntary load shedding expected compared to 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 quantity (in MWh) of 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 AER published VCRs and JEN's customer load composition.

JEN forecasts and models hourly load for the planning period and quantifies the EUE (involuntary load shedding) by comparing forecast load to network capabilities under system normal and credible network outage conditions.

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

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 the load;
- Costs to other parties;
- Option value; and

- Electrical energy losses.

6.2.1 Timing of expenditure

Under the Victorian Electricity Safety Act 1998 (Act) and the Electricity Safety (Bushfire Mitigation) Regulations 2013 (Regulations), JEN is obliged to ensure that all 22 kV distribution feeders originating from COO meet specified technical performance requirements by 1 May 2023. The compliance obligations effectively require these feeders to be protected by REFCL technology or otherwise requiring these feeders to be the subject of exemptions under the Act and Regulations. The timing for regulatory compliance is the same under each credible option.

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 to make the load available for curtailment and actually have it curtailed during a network event. A credible demand-side reduction option leads to a change in the amount of voluntary load curtailment.

Compared to the Base Case, an increase in voluntary load curtailment 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 Coolaroo supply area. This assessment showed there was insufficient potential for voluntary load curtailment to meet the 'Required Capacity' of the Regulations. Therefore, this market benefit was not quantified as it not was considered material with respect to differentiating between options.

6.2.3 Changes in load transfer capacity and embedded generators

JEN has assessed the potential for customers to use the standby and standalone generation and/or storage solutions in the Coolaroo supply area. This assessment showed insufficient potential for generation or storage to meet the 'Required Capacity' of the Regulations. Therefore, this market benefit was not quantified as it was not considered material with respect to differentiating between options.

6.2.4 Costs to other parties

The Coolaroo Area primary need relates to meeting Regulatory obligations by a prescribed date. 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 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 Coolaroo supply area primary need relates to meeting regulatory compliance obligations by a prescribed date. It is considered that in this case, there no value in retaining flexibility. JEN has therefore not attempted to estimate any additional option value market benefit for this RIT-D assessment.

6.2.6 Electrical energy losses

The change in electrical energy losses between the options is immaterial. The consideration of electrical energy losses would not change the rankings of the options given the proportionality test. Therefore, the market benefits associated with electrical energy losses are not considered part of this RIT-D and have consequently been excluded from the market benefit assessments.

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.

Since this RIT-D is driven primarily by a bushfire-start mitigation regulatory compliance need, demand growth is not the major consideration. Nonetheless, as the reliability of supply is a second identified need, 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 include:

- VCR;
- Capital costs; and
- Discount rate.

6.3.1 Value of Customer Reliability

The cost of unserved energy 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 constraints on its network, JEN applies VCR values based on the AER's value of customer reliability review and applying JEN's customer load composition, comprising an approximate 32% residential, 44% commercial and 24% industrial split. JEN's composite VCR figure is $41,738/MWh. Sensitivities to the base VCR of ±10% have been considered.

6.3.2 Capital costs

JEN's internal estimation teams have estimated the network project capital costs. Consideration has been given to similar projects and expected costs based on site-specific construction complexities and industry experience. Capital costs are presented in real 2020 dollars.

These capital cost estimates have been prepared for planning purposes and are therefore subject to an estimated range of ±30%. A range of +50% to -10% been applied to the sensitivity studies for this RIT-D.

6.3.3 Discount rate

A discount rate of 2.5% has been applied in assessing the Net Present Value (NPV) assessment of credible options. Sensitivities to the base discount rate of ±1% have been considered.

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 2021 to 2030. Each potential option has been ranked according to its net economic benefit, being 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 customer interruptions costs

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:

- The average distribution feeder outage rate is calculated based on JEN historic data;
- The average feeder outage repair time (or supply restoration time) for underground assets is 8 hours, and overhead assets are 4 hours;
- The average feeder operational response time to perform load transfers to adjacent feeders is 1 hour;
- Feeder average demand is used to determine EUE for a feeder outage that cannot be transferred to adjacent feeders due to REFCL technical limitations;
- Feeder load factor of 0.55 and power factor of 0.93 lag;
- Sub-transmission line outage frequency, which is 0.1 outages per kilometre of line length per year; and
- Sub-transmission line outage average duration of 6 hours per outage.

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

This option considers the impact of a "Do Nothing" scenario, including no additional investment in the Coolaroo supply area. The current capability of the zone substations in the area are presented in Table 7–1.

Table 7–1: Option 1 – Summer Ratings (MVA)

Zone Substation	BD	BMS	COO	ST
'N' Rating	123.0	47.6	47.6	95.2
'N-1' Rating	123.7	38.0	38.0	79.7

The network limitations under the Base Case are highlighted in Table 7–2 against each forecast maximum demand.

Table 7–2: Option 1 – Summer 10% and 50% PoE Forecast Maximum Demand (MVA)

Zone Sub.	BD		BMS		COO		ST	
Year	**10PoE**	**50PoE**	**10PoE**	**50PoE**	**10PoE**	**50PoE**	**10PoE**	**50PoE**
2020 (Actual)	72.4		29.1		43.7		76.4	
2021	79.0	71.6	31.0	28.1	49.4	43.0	82.0	75.1
2022	79.2	71.9	30.9	28.1	51.0	44.4	83.4	76.6
2023	78.8	71.5	30.9	28.0	52.1	45.3	83.9	77.0
2024	77.9	70.9	30.7	27.9	52.7	46.0	83.3	76.6
2025	77.5	70.6	30.6	27.9	53.2	46.5	83.3	76.7

Zone Sub.	BD		BMS		COO		ST	
Year	**10PoE**	**50PoE**	**10PoE**	**50PoE**	**10PoE**	**50PoE**	**10PoE**	**50PoE**
2026	77.3	70.0	30.5	27.7	53.5	46.4	84.1	76.9
2027	76.7	69.8	30.3	27.6	53.5	46.7	84.3	77.6
2028	76.7	69.6	30.2	27.5	53.9	46.9	85.2	78.2
2029	76.4	69.3	30.1	27.3	54.2	47.2	85.9	78.8
2030+	75.7	69.1	29.8	27.2	54.2	47.4	86.1	79.5

The incremental impact of the network limitations under Option 1 (assuming that under "Do Nothing", the network needs to be de-energised to meet the 'Required Capacity') is presented in Table 7–3.

Table 7–3: Option 1 - Cost of Expected Unserved Energy (real million, $2020)

Single Contingency Event	Impact of Contingency Event	Option 1
System normal	Forced de-energisation of COO zone substation because of Regulatory requirement to comply with the 'Required Capacity'. Approx. 50% of COO zone substation load (22MVA) at risk for 24 hours per annum[18].	98.7
Feeder COO-11	Nil	0.0
Feeder COO-12	Nil	0.0
Feeder COO-13	Nil	0.0
Feeder COO-14	Nil	0.0
Feeder COO-21	Nil	0.0
Feeder COO-22	Nil	0.0
One COO transformer	Nil	0.0
One sub-transmission line	Nil	0.0
Present Value Cost		**98.7**

7.1.2 Option 2: Install Isolation Transformers on Underground Feeders and REFCLs at COO

Under Option 2, the maximum demand forecasts for BD, BMS, COO and ST zone substations over the forward 10-year planning period remain the same. The incremental impact of the network limitations under Option 2 is presented in Table 7–4.

Table 7–4: Option 2 - Cost of Expected Unserved Energy (real million, $2020)

Single Contingency Event	Impact of Contingency Event	Option 2
Feeder COO-11	100% of customers cannot be transferred to COO-21 because of COO Bus #2 capacitance limit until the fault is repaired.	38.59
Feeder COO-12	100% of customers cannot be transferred to COO-11 due to the thermal capacity limit.	0.31
Feeder COO-13	70% of customers cannot be transferred to COO-11 or ST-31 because of the capacitance limit (80A) on COO-11 and the thermal capacity limit on ST-31, until the fault is repaired.	2.15
Feeder COO-14	25% of customers cannot be transferred to adjacent feeders. Isolation transformer provides 75% of customer transfer to COO-22 and ST-32.	0.03
Feeder COO-21	100% of customers cannot be transferred to adjacent feeders COO-11 or COO-14 due to the capacitance limit on COO-11 or COO-14 as non-REFCL via an isolation transformer.	18.37
Feeder COO-22	25% of customers cannot be transferred to adjacent feeders. Isolation transformer provides 75% of customer transfer to COO-14 and ST-32.	0.04

18 For the purpose of this economic assessment, a conservative 24 hour per annum duration have been assumed, however in practice this duration would generally be much greater as it would be applied to the bushfire season and on total fire ban days.

Single Contingency Event	Impact of Contingency Event	Option 2
One COO transformer	0MVA of load transfer from COO zone substation to ST zone substation.	1.30
One sub-transmission line	No customer is at risk.	0.0
Present Value Cost		**60.8**

7.1.3 Option 3: Install REFCLs at COO

Under Option 3, it is expected that there will be a net load transfer from COO to ST of approximately 11MVA from summer 2024 onwards. This outcome results in the demand reduction at COO, which will likely mean avoiding the need for any augmentation work to meet load growth requirement for COO within the forward 10-year planning period. However, the increase in demand at ST would necessitate augmentation work or alternative non-network solution to address the emerging capacity constraint within the planning period. There is no change to the BD and BMS demand forecast

Table 7–5: Option 3 – Summer 10% and 50% PoE Forecast Maximum Demand (MVA)

Zone Substation	COO		ST	
Year	10PoE	50PoE	10PoE	50PoE
2020 (Actual)	43.7		76.4	
2021	49.4	43.0	82.0	75.1
2022	51.0	44.4	83.4	76.6
2023	52.1	45.3	83.9	77.0
2024	41.7	36.4	94.3	86.2
2025	42.2	36.9	94.3	86.3
2026	42.5	36.8	95.1	86.5
2027	42.5	37.1	95.3	87.2
2028	42.9	37.3	96.2	87.8
2029	43.2	37.6	96.9	88.4
2030+	43.2	37.8	97.1	89.1

The incremental impact of the network limitations under Option 3 is presented in Table 7–6.

Table 7–6: Option 3 - Cost of Expected Unserved Energy (real million, $2020)

Single Contingency Event	Impact of Contingency Event	Option 3
Feeder COO-11	100% of customers cannot be transferred to COO-21 because of COO Bus #2 capacitance limit until the fault is repaired.	38.59
Feeder COO-12	100% of customers cannot be transferred to COO-11 due to the thermal capacity limit.	0.31
Feeder COO-13	70% of customers cannot be transferred to COO-11 or ST-31 because of the capacitance limit (80A) on COO-11 and the thermal capacity limit on ST-31, until the fault is repaired.	2.15
Feeder COO-14	50% of customers cannot be transferred to COO-22, ST-31 or ST-32 because of the capacitance limit on COO Bus #2 and the thermal capacity limit on ST-31 and ST-32, until the fault is repaired.	0.17
Feeder COO-21	100% of customers cannot be transferred to adjacent feeders COO-11 or ST-31 due to the capacitance limit on COO-11 or ST-31 being a non-REFCL feeder.	18.37
Feeder COO-22	50% of customers cannot be transferred to adjacent feeders due to the capacity limit on ST-31 and ST-32.	0.44
One COO transformer	Approximately 11MVA of load transfer from COO zone substation to ST zone substation.	0.20

Single Contingency Event	Impact of Contingency Event	Option 3
One sub-transmission line	No customer is at risk.	0.0
Present Value Cost		**60.2**

7.1.4 Option 4: Two REFCL Zone Substations in JEN

Under Option 4, it is expected that there will be a net load transfer from COO to the new GVE of approximately 15MVA from summer 2024 onwards. This results in the demand reduction at COO, which will avoid any augmentation work to meet the load growth requirement for COO. The new GVE zone substation will also have sufficient capacity[19] to meet its ongoing load growth over the forward 10-year planning period. There is no change to the ST, BD and BMS demand forecast.

Table 7–7: Option 4 – Summer 10% and 50% PoE Forecast Maximum Demand (MVA)

Zone Substation	COO		GVE	
Year	10PoE	50PoE	10PoE	50PoE
2020 (Actual)	43.7		0.0	
2021	49.4	43.0	0.0	0.0
2022	51.0	44.4	0.0	0.0
2023	52.1	45.3	0.0	0.0
2024	37.7	32.9	15.0	13.1
2025	38.2	33.4	15.0	13.1
2026	38.5	33.4	15.0	13.1
2027	38.5	33.6	15.0	13.1
2028	38.9	33.8	15.0	13.1
2029	39.2	34.1	15.0	13.1
2030+	39.2	34.3	15.0	13.1

The incremental impact of the network limitations under Option 4 is presented in Table 7–8.

Table 7–8: Option 4 - Cost of Expected Unserved Energy (real million, $2020)

Single Contingency Event	Impact of Contingency Event	Option 4
Feeder COO-11	Reliability risk reduced to 1/3 compares with Options 7 and 11 because COO-11 is split into 3 feeders, reducing exposure by 2/3.	12.92
Feeder COO-12	100% of customers can be transferred to COO-11.	0.0
Feeder COO-13	100% of customers can be transferred to COO-11.	0.0
Feeder COO-14	No customer is at risk with the prolonged outage, as there are likely to be transfers to adjacent feeders on the same bus.	0.0
Feeder COO-21	No customer is at risk with the prolonged outage, as there are likely to be transfers available to adjacent feeders on the same bus.	0.0
Feeder COO-22	No customer is at risk with the prolonged outage, as there are likely to be transfers available to adjacent feeders on the same bus.	0.0
One COO transformer	Approximately 15MVA of load transfer from COO zone substation to GVE zone substation.	0.01
One sub-transmission line	No customer is at risk.	0.0
Present Value Cost		**12.9**

[19] 'GVE' ratings would be the same as COO.

7.1.5 Option 5: Build a New REFCL Zone Substation ('GVE')

Under Option 5, it is expected that there will be a net load transfer from COO to the new GVE of approximately 15MVA from summer 2024 onwards. This results in the demand reduction at COO, which will avoid any augmentation work to meet the load growth requirement for COO. The new GVE zone substation will also have sufficient capacity[20] to meet its ongoing load growth over the forward 10-year planning period. There is no change to the ST, BD and BMS demand forecast.

Table 7–9: Option 5 – Summer 10% and 50% PoE Forecast Maximum Demand (MVA)

Zone Substation	COO		GVE	
Year	10PoE	50PoE	10PoE	50PoE
2020 (Actual)	43.7		0.0	
2021	49.4	43.0	0.0	0.0
2022	51.0	44.4	0.0	0.0
2023	52.1	45.3	0.0	0.0
2024	37.7	32.9	15.0	13.1
2025	38.2	33.4	15.0	13.1
2026	38.5	33.4	15.0	13.1
2027	38.5	33.6	15.0	13.1
2028	38.9	33.8	15.0	13.1
2029	39.2	34.1	15.0	13.1
2030+	39.2	34.3	15.0	13.1

The incremental impact of the network limitations under Option 5 is presented in Table 7–10.

Table 7–10: Option 5 - Cost of Expected Unserved Energy (real million, $2020)

Single Contingency Event	Impact of Contingency Event	Option 5
Feeder COO-11	Reliability risk reduced to 1/3 compares with Options 7 and 11 because COO-11 is split into three feeders, reducing exposure by 2/3.	12.92
Feeder COO-12	100% of customers can be transferred to COO-11 or ST-12.	0.0
Feeder COO-13	100% of customers can be transferred to COO-11 or BD-14.	0.0
Feeder COO-14	No customer is at risk with the prolonged outage, as there are transfers to COO-21, COO-22, GVE-12 and GVE-13.	0.0
Feeder COO-21	No customer is at risk with the prolonged outage, as there are transfers available to COO-11, COO-14, GVE-11, GVE-12 and GVE-13.	0.0
Feeder COO-22	25% of customers cannot be transferred to adjacent feeders – 75% transfers to COO-14 and ST-32, indirect to COO-21, GVE-12, GVE-13.	0.04
One COO transformer	Approximately 15MVA of load transfer from COO zone substation to GVE zone substation.	0.01
One sub-transmission line	Customers at GVE zone substation is at risk of load shedding.	7.7
Present Value Cost		**20.7**

7.1.6 Option 6: Install Two REFCLs at COO Under a Split Bus Configuration with One High-Performance REFCL

Under Option 6, it is expected that there will be a net load transfer from COO to BD of approximately 7.5MVA and from BD to BMS of approximately 3.3MVA from summer 2024 onwards. COO zone substation will also be reconfigured to operate as two separate transformer and bus groups, known as COO Transformer No.1 and COO

[20] 'GVE' ratings would be the same as COO.

Transformer No.2; each will have a rating of 33MVA. This results in a demand reduction at COO, which will avoid any augmentation work to meet the load growth requirement for COO. The new COO Transformer No.1, COO Transformer No.2, BD and BMS zone substations will have sufficient capacity to meet its ongoing load growth over the forward 10-year planning period. There is no change to ST demand forecast.

Table 7–11: Option 6 – Summer 10% and 50% PoE Forecast Maximum Demand (MVA)

Zone Sub.	BD		BMS		COO 1		COO 2	
Year	10PoE	50PoE	10PoE	50PoE	10PoE	50PoE	10PoE	50PoE
2020 (Actual)	72.4		29.1		43.7			
2021	79.0	71.6	31.0	28.1	49.4	43.0		
2022	79.2	71.9	30.9	28.1	51.0	44.4		
2023	78.8	71.5	30.9	28.0	52.1	45.3		
2024	82.1	74.6	34.0	31.0	15.0	13.1	30.2	26.1
2025	81.7	74.3	33.9	31.0	15.0	13.1	30.7	26.6
2026	81.5	73.7	33.8	30.7	15.0	13.1	31.0	26.6
2027	80.9	73.5	33.5	30.7	15.0	13.1	31.1	26.8
2028	80.8	73.3	33.5	30.5	15.0	13.1	31.5	27.1
2029	80.6	73.1	33.3	30.4	15.0	13.1	31.8	27.4
2030+	79.9	72.8	33.0	30.3	15.0	13.1	31.8	27.5

The incremental impact of the network limitations under Option 6 is presented in Table 7–12.

Table 7–12: Option 6 - Cost of Expected Unserved Energy (real million, $2020)

Single Contingency Event	Impact of Contingency Event	Option 6
Feeder COO-11	Reliability risk reduced to 1/3 compared with Options 7 and 11 because COO-11 is split into three feeders, reducing exposure by 2/3.	12.92
Feeder COO-12	100% of customers can be transferred to BD-4 or ST-12.	0.0
Feeder COO-13	100% of customers can be transferred to COO-21 or BD-14.	0.0
Feeder COO-14	No customer is at risk with the prolonged outage, as there are transfers to COO-012, COO-23, COO-24, and ST21.	0.0
Feeder COO-21	No customer is at risk with the prolonged outage, as there are transfers available to COO-11, COO-12, COO-22 and BD-4.	0.0
Feeder COO-22	No customer is at risk with the prolonged outage, as there are load transfers available to ST-021, ST-32 and new COO-22.	0.0
One COO transformer	7.5MVA of load transfer from COO to BD, and 3.3MVA from BD to BMS. COO reconfigured as COO Transformer No.1 and COO No.2.	0.01
One sub-transmission line	No customer is at risk.	0.0
Present Value Cost		**12.9**

7.2 Net economic benefits

JEN's options assessment considered project and ongoing incremental operational costs, HV customer costs to comply, and EUE (reliability) costs based on forecast demand and network capability. A summary of the present value cost analysis assessed for each option is presented in Table 7-13.

Table 7-13: Summary of Present Value Cost Analysis (real million, $2020)

Option	Capital Cost	Incremental O&M	HV Customer Cost	EUE Cost	Total Cost	Ranking
Option 1	0.0	0.0	0.0	98.7	98.7	5
Option 2	25.8	2.2	9.1	60.8	97.8	4
Option 3	23.6	2.2	9.1	60.2	95.1	3
Option 4	49.5	2.2	9.1	12.9	73.7	2
Option 5	35.2	2.2	1.3	20.7	59.3	N/A[21]
Option 6	34.8[22]	2.2	9.1	12.9	59.0	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 7–14 show that the feasible option that maximises the net economic benefit is Option 6. This option is JEN's proposed preferred option because it addresses the identified need and maximises the net economic benefit compared to the other options considered in this RIT-D.

Table 7–14: Present Value of Net Economic Benefits of each option (real million, $2020)

Option	PV Cost	PV Benefits	NPV	Ranking
Option 1: Do Nothing	0.0	0.0	0.0	5
Option 2: Install Isolation Transformers on Underground Feeders and REFCLs at COO	37.1	37.9	0.8	4
Option 3: Install REFCLs at COO	34.9	38.5	3.6	3
Option 4: Two REFCL Zone Substations in JEN	60.8	85.8	25.0	2
Option 5: Build a New REFCL Zone Substation ('GVE')	38.5	78.0	39.3	N/A
Option 6: Install Two REFCLs at COO Under a Split Bus Configuration with One High-Performance REFCL	46.1	85.8	39.7	1

The analysis also demonstrated that the conclusion of Option 6 being the preferred option was not sensitive to credible movements in key assumptions, as shown in Table 7–15 below.

[21] No longer feasible.

[22] Project cost for option 6 is $36.9M (real, $2021).

Table 7–15: Net Economic Benefits sensitivities (real million, $2020)

Scenario	High cost, low VCR and low discount rate				Low cost, high VCR and high discount rate			
Option	Cost	Benefits	NPV	Ranking	Cost	Benefits	NPV	Ranking
Option 1	0.0	0.0	0.0	2	0.0	0.0	0.0	5
Option 2	50.9	40.8	-10.1	5	33.9	35.4	1.5	4
Option 3	47.6	41.4	-6.2	4	31.9	36.0	4.1	3
Option 4	87.1	86.4	-0.7	3	54.8	85.2	30.4	2
Option 5	57.4	78.8	21.4	N/A	34.5	77.3	42.8	N/A
Option 6	64.7	86.4	21.7	1	41.8	85.2	43.4	1

7.3 Preferred option optimal timing

The RIT-D options analysis concludes that:

- Option 6, installing two REFCLs at COO under a split-bus configuration with one high-performance REFCL, is the preferred network option because it addresses the identified need and maximises the present value of net market benefits compared to all the other options;
- The optimum timing of the investment is to have the preferred network option in service by 1 May 2023 to align with the timing of the bushfire-start mitigation regulatory obligations prescribed for COO; 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 6) was tested under a range of sensitivities, including variations in costs, VCR and other base assumptions. Option 6 was confirmed to provide positive economic benefits in each case and is the highest-ranked option.

8. Conclusions and next steps

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

8.1 Preferred solution

In line with the assessment, the recommended solution is Option 6, 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 bushfire risk-neutral outcome and is in the long-term interests of JEN's customers.

Option 6 (installing two REFCLs at COO under a split-bus configuration with one high-performance REFCL) includes the following works:

- Install two REFCLs at COO under a split bus configuration—that is, one REFCL on COO Transformer No.1 with high-performance settings to meet the 'Required Capacity', and one REFCL on COO Transformer No.2 with base performance settings which will be operated below the 'Required Capacity', with the 22kV bus tie CB normally open. This arrangement will ensure the station will operate correctly by reducing the earth fault current on the COO Transformer No.2 side to a sufficiently low level that will avoid inadvertent tripping of COO Transformer No.1 side;
- Transfer sections of the existing COO 22kV network with high bushfire-start risk, mainly COO-011, to COO Transformer No.1 (high-performance REFCL)—thereby providing REFCL protection to those 22kV feeders in compliance with the Act and the Regulations. The remaining sections of the COO supply area will be transferred to COO Transformer No. 2 (base performance REFCL) and neighbouring non-REFCL BD zone substation to reduce the capacitance level to within acceptable design level on the base performance REFCL; and
- Undertake various bushfire mitigation activities to reduce the bushfire risk for those polyphase electric lines of an overhead construction within an urban environment that pose some risk to a fire ignition that could propagate to a bushfire—therefore resulting in a bushfire risk-neutral outcome—and obtain exemptions under the Act and Regulations in respect of these lines.

The total capital cost of Option 6 is $36.9 million (real $2021 including overheads), with an additional O&M expenditure for REFCL compliance testing of $0.31 million per annum. The total cost for HV customers in the Coolaroo supply area to comply with the Regulations is $9.3 million.

8.2 Next steps

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

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

Submissions should be lodged on or before 3 September 2021. All submissions will be published on JEN's website. If you do not wish to have your submission (or parts of the submission) published, please indicate this clearly.

Following our consideration of any submissions on this DPAR, we 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 the final stage in the RIT-D process.

JEN intends to publish the FPAR by 1 October 2021. 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 2021 Distribution Annual Planning Report.