Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review Proposal

Northern Growth Corridor Network Development Strategy

ELE PL 0025

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Glossary

10% POE (summer)	Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE (summer)	Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE (winter)	50% POE and 10% POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.
Augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation is usually triggered by growing customer demand in areas of the network with limitations.
Capacity	Refers to the network's capability to transfer electricity to customers.
Continuous Rating	The permissible maximum demand to which a conductor or cable may be loaded on a continuous basis.
Cyclic Rating	The permissible maximum demand to which a conductor or cable may be loaded on a cyclic basis.
Consumer Energy Resources (CER)	Solar PV, micro-generators, batteries (including electric vehicles), flexible load and other Embedded Generation connected within the distribution network.
Discount Rate	The regulated Weighted Average Cost of Capital (WACC).
Distribution Feeders	Radial 22kV, 11kV or 6.6kV powerlines that emanate from zone substations to supply Distribution Substations or HV customers.
Exit Cable	The underground cable connected to the HV distribution feeder circuit breaker that leaves the boundary of the zone substation.
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 Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 360,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Limitation	Refers to a limitation on a network asset's ability to transfer power due to its rating, failure rate or condition.
Maximum demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Network	Refers to the physical assets required to transfer electrical energy to customers.
Non-network	Refers to anything potentially affecting the transfer of electricity to customers that does not involve the network.
Non-network alternative	A response to growing customer demand that does not involve a traditional network solution.
Open Point	An isolation device on a distribution feeder that is in a normally open state.
Operations & Maintenance expenditure (O&M)	Expenditure (ongoing) for operating and maintaining the network.

Power Factor (pf)	The ratio of active power to apparent power. A unity power factor indicates no reactive power through the element. Power factor is specified as either leading or lagging.
Present Value	The value of a cost or benefit in the future, discounted to today's value using the Discount Rate.
Probability of exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Probabilistic Planning	A planning methodology involving estimating the cost of a network limitation with consideration of demand, network capability, and the likelihood and severity of network outages and operating conditions.
Reconductor(ing)	Replacing a section of conductor with another of higher rating.
Regulatory Investment Test for Distribution (RIT-D)	A test administered 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	The measure of the duration or frequency of the distribution system to provide uninterrupted supply to customers over a defined time.
Sub-transmission	Overhead lines and underground cables connecting terminal stations to zone substations. These are operated at 66 kV.
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.
Terminal Station	Sites where transmission voltages are transformed down to sub-transmission voltages. These sites and the assets within them are not owned by JEN.
Transfer Capability	The amount of capacity available for a load transfer from one substation to another.
Transmission Connection Assets	The assets within a Terminal Station that are planned by JEN and the other DNSPs that are connected to the Terminal Station.
Utilisation	The Maximum Demand expressed as a percentage of its rating.
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	Sites where sub-transmission voltages are transformed down to distribution voltages. These sites are owned by JEN. They are the upstream supply source for HV distribution feeders.

Abbreviations

A	Ampere
AAC	All Aluminium Conductor
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BD	Broadmeadows Zone Substation (existing non-REFCL zone substation)
BESS	Battery Energy Storage System
BMS	Broadmeadows South Zone Substation (existing non-REFCL zone substation)
CB	Circuit Breaker
CBN	Craigieburn Zone Substation (proposed REFCL zone substation)
CHP	Cable Head Pole
CIC	Customer Initiated Capital
COO	Coolaroo Zone Substation (existing REFCL zone substation)
CER	Consumer Energy Resources
DM	Demand Management
(E)	Existing
EUE	Expected Unserved Energy
EV	Electric Vehicle
(F)	Future
GVE	Greenvale Zone Substation (future REFCL zone substation)
HV	High Voltage
JEN	Jemena Electricity Network
KLO	Kalkallo Zone Substation (owned by AusNet Services)
kV	kilo-Volts
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
NDS	Network Development Strategy
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules or Neutral Earthing Resistor (depending on context)
(N)	New (or system normal - all critical plant in service, depending on context)
(N-1)	Single contingency - a single critical item of plant out service
N/O	Normally Open
NPV	Net Present Value
O&M	Operations and Maintenance
OH	Overhead Line

OLTC	On-Load Tap-Changer
OOS	Out of Service
PF	Power Factor
PoE	Probability of Exceedance
PV	Present Value (or Photovoltaic, depending on context)
PVR	Present Value Ratio
RCGS	Remote Controlled Gas-insulated Switch
REFCL	Rapid Earth Fault Current Limiter
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SAPS	Standalone Power Systems
SLD	Single Line Diagram
SMTS	South Morang Terminal Station (owned by AusNet Services)
SSS	Somerton Switching Station (for Somerton Power Station)
ST	Somerton Zone Substation
TTS	Thomastown Terminal Station (owned by AusNet Services)
UG	Underground Cable
VCO	Visyboard Coolaroo (customer substation)
VCR	Value of Customer Reliability
VEDCoP	Victorian Electricity Distribution Code of Practice
WACC	Weighted Average Cost of Capital

Executive Summary

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

Our customers expect us to deliver and maintain a reliable electricity supply at an efficient cost over the lifecycle of our assets. To do this, we must choose the most prudent and efficient solutions that address current and emerging network limitations. In the context of the National Electricity Market (**NEM**), this means choosing an investment plan that maximises the present value of net economic benefits to all those who produce, consume and transport electricity.

This document articulates the Network Development Strategy (**NDS**) and the plans for the area of the JEN, north of Barry Rd Campbellfield, east of Mickleham Rd and bordered to the east and north by the AusNet service area boundary, servicing the suburbs of Mickleham, Craigieburn, Somerton, Campbellfield, Meadow Heights, Roxburgh Park, Greenvale and Coolaroo.

The area is supplied by our Coolaroo (**COO**), Somerton (**ST**), and Broadmeadows (**BD**) zone substations and AusNet Services' Kalkallo (**KLO**) zone substation by way of a network of 22 kV distribution feeders. This supply area currently services over 52,121 customers and falls within the Victorian Planning Authority's[1] Northern Growth Corridor.

This NDS presents the current and emerging limitations within this supply area over a 10-year planning horizon and identifies solutions to address identified network needs.

Identified Needs

In 2012, following the extension of the edge of the urban boundary, the Northern Growth Corridor Plan[2] was developed to set out the planning framework for increased development north along the Hume Highway/Hume Freeway corridor, and in particular areas around and immediately north of Craigieburn. Since that time, development within the Northern Growth Corridor has been progressing rapidly and this expansion is expected to continue for at least the next 10 years. Growth in the corridor has progressively been extending north and this has been evident with JEN now experiencing high volumes of customer connections and rapid load growth in the far north of its service area. Since JEN's 2015 release of this Northern Growth Corridor NDS, growth has now extended north of Craigieburn into Mickleham.

The population of Craigieburn in 2022 was 67,912 and this is forecast by Hume City Council to grow to 78,929 by 2041, an increase of 16.2%. This growth is due to additional dwellings in new housing lots and through infill and medium density development in existing residential areas. The population of Mickleham in 2022 was 17,671 and this is forecast to grow to 47,670 by 2041, an increase of 168.4%. This growth is predominantly due to new dwellings in housing lots for new subdivisions.

Maximum demand for the supply area is expected to grow on average by 3.7% per annum during the next 10-year period. Some of the existing zone substations and 22 kV distribution feeders supplying the area, will not have sufficient capacity to meet this expected increase in maximum demand. A number of existing assets in the area are already or forecast to be highly utilised, including two zone substations (COO and ST) and ten 22 kV distribution feeders (BD 08, COO23, KLO13, KLO21, KLO22, ST 11, ST 12, ST 22, ST 32 and ST 33). Staged, targeted augmentations of the network are needed to connect new customers and maintain current levels of supply reliability.

With the development of the new estates having HV underground feeders, the increased cable capacitance is expected to the deteriorate the performance of REFCL-protected feeders in the area. Network rearrangements

[1] https://vpa.vic.gov.au/

[2] Growth Corridor Plan, Managing Melbourne Growth: Growth Areas Authority Nov 2012.

will be needed to segregate overhead and underground networks so as to maintain REFCL performance at COO in compliance with Victorian bushfire safety regulations.

Options Considered

This NDS presents a range of credible options to meet the forecast demand for electricity over a 10-year planning horizon and maintain a safe and reliable supply to customers within the supply area. These include:

- Option 1: **Do Nothing** (base case);
- Option 2: **Craigieburn Plan**;
- Option 3: **Greenvale Plan;**
- Option 4: Battery Energy Storage System (BESS) Plan; and
- Option 5: Demand Management (DM) Plan.

A summary of the 20-year NPV cost-benefit analysis assessed for each option over a 10-year investment period, is presented in Table ES-1.

Table ES-1: Summary of Cost-Benefit Analysis (FY24 $M)

Option	Total Capital Cost	Present Value of Capital and O&M Cost	Present Value of Reliability Benefit	Net Present Value (NPV)	Ranking
Option 1 - Do Nothing	0	0.0	0.0	0.0	5
Option 2 – Craigieburn Plan	**49.2**	**51.6**	**489.1**	**437.5**	**1**
Option 3 - Greenvale Plan	61.7	64.7	490.9	426.3	2
Option 4 – BESS Plan	0	255.3	489.1	233.8	4
Option 5 – DM Plan	0	106.0	489.1	383.1	3

Preferred Option

The assessment demonstrates that the preferred network development plan is to implement Option 2 (Craigieburn Plan) because this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred Option 2 provides a 20-year present value net market benefit of $437 million, with a present value of $44.9 million of investment (over 10-years, 2025 to 2034). The market benefit forecast to be delivered by the preferred solution is driven by of the reduction in expected unserved energy over the analysis period.

The preferred network Option 2 to address the network limitations includes the following project components**:**

Table ES-2: Option 2 - Craigieburn Plan

Timing	Projects	Cost (FY24$)	Limitation Addressed
2026	Augment feeder BD0-008	[redacted]	ST (N & N-1) overload
2026	New feeder KLO-023		KLO13, KLO21 overload
2027	Coolaroo No.1 bus cable transfers		COO Bus No.1 REFCL
2027	Coolaroo No.2 bus feeders		COO Bus No.2 REFCL COO (N) overload COO23 overload
2027	Establish new Craigieburn (CBN) zone substation - zone substation works 66 kV sub-transmission line extension[3] Establish new Craigieburn (CBN) zone substation - HV feeder works		ST (N & N-1) overload ST feeders overload KLO22 overload
2033	Third 66/22 kV transformer at CBN		CBN (N & N-1) overload
Total		**$49.2 million**	
Present Value Total		**$44.9 million**	

The estimated total capital cost of Option 2 for JEN over 10-years to address the identified network limitations is $49.2 million (FY24$), of which $8.6 million is outside of the FY2027-31 regulatory control period. Table ES-3 lists the projects and their associated costs over the FY2027-31 regulatory control period.

A sensitivity analysis was carried out to assess the effect of changing the capital costs, discount rate and demand forecasts. The results showed that changing these variables did not change the optimal timing of the projects in the development plan neither does it change Option 2 as the preferred option.

Table ES-3: Option 2 - Craigieburn Plan, projects within FY2027-31 regulatory control period

Timing	Projects	Cost (FY24$)	Limitation Addressed

[3] The 66kV sub-transmission line extension work is planned to be completed in 2025 as part of customer initiated project and the associated cost is excluded from the development plan. Refer to Major Customers NDS for further details.

[4] A RIT-D is currently underway for this project.

2026	Augment feeder BD0-008	[redacted]	ST (N & N-1) overload
2026	New feeder KLO-023		KLO13, KLO21 overload
2027	Coolaroo No.1 bus cable transfers		COO Bus No.1 REFCL
2027	Coolaroo No.2 bus feeders		COO Bus No.2 REFCL COO (N) overload COO23 overload
2027	Establish new Craigieburn (CBN) zone substation - zone substation works 66 kV sub-transmission line extension[6] Establish new Craigieburn (CBN) zone substation - HV feeder works		ST (N & N-1) overload ST feeders overload KLO22 overload
Total		**$40.7 million**	

[5] $8.6M of the recommended plan project costs are outside the FY2027-31 regulatory control period.

[6] The 66kV sub-transmission line extension work is planned to be completed in 2025 as part of customer initiated project and the associated cost is excluded from the development plan. Refer to Major Customers NDS for further details.

[7] A RIT-D is currently underway for this project.

1. Introduction

This chapter outlines the purpose of this NDS, provides an overview of the supply area, describes the general arrangement of the electricity network, and gives a brief overview of the network limitations in this area.

1.1 Purpose

JEN is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The JEN 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, as shown in Figure 1-1.

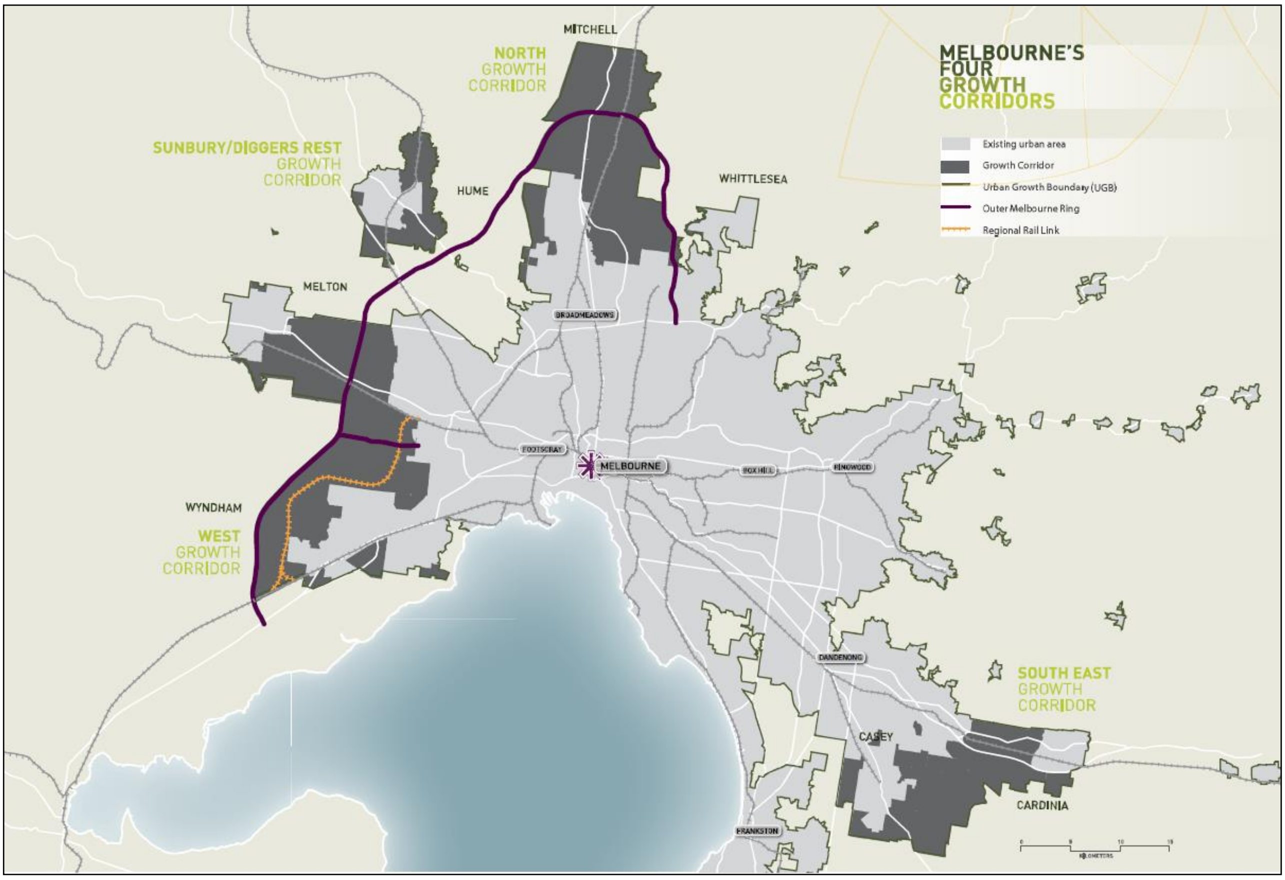
This document articulates the NDS for the electricity network north of Barry Rd Campbellfield, east of Mickleham Rd and bordered to the east and north by the AusNet service area boundary, servicing the suburbs of Mickleham, Craigieburn, Somerton, Campbellfield, Meadow Heights, Roxburgh Park, Greenvale and Coolaroo. It presents the current and emerging limitations within this supply area over a 10-year planning horizon and identifies options to resolve these constraints

Figure 1-1 NDS Supply Area within the JEN Service Area

1.2 Supply Area Overview

The Growth Areas Authority (now known as the Victorian Planning Authority[8]) identified four new areas to meet Melbourne's urban development and population growth between now and 2030. As part of this process, the urban boundaries were expanded and planning documents were developed to guide their development. The growth corridors are the Northern Growth Corridor, the Sunbury/Diggers Rest growth corridor, the West Growth Corridor and the South East Growth Corridor.

Figure 1-2 Melbourne Growth Corridors



The Northern Growth Corridor and the North-western Growth Corridor impact JEN's planning and investment as 40% of the former and 100% of the latter fall within the area supplied by JEN.

The Northern Growth Corridor Plan covers the areas of Greenvale, Craigieburn, Mickleham, Donnybrook, Kalkallo, Mernda, Wollert and Beveridge. It was estimated that, over the next 20-30 years, the area's population will increase to between 260,000 and 330,000 people, its number of dwellings will increase to between 93,000 and 117,000 and that jobs will increase to between 83,000 and 105,000[9].

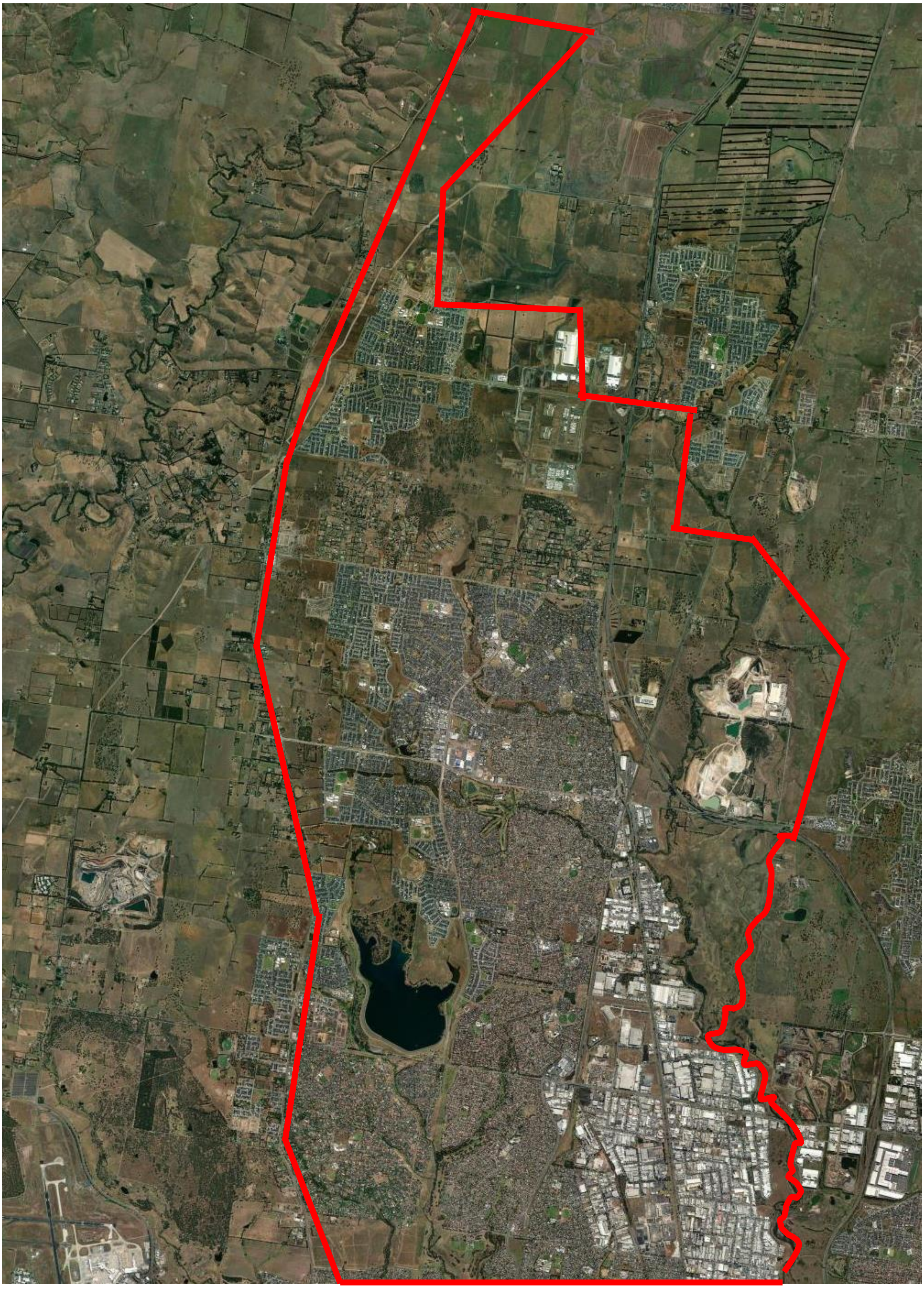
A large part of the Northern Growth Corridor is within the Municipal area of Hume and falls within the JEN service area. The plan makes provision for approximately 500 hectares of industrial land, 1550 hectares of residential land and 70 hectares of commercial land within the JEN area.

The parts of the Northern Growth Corridor that lie within the JEN electricity distribution network service area (and is within the scope of this NDS) is bounded by Barry Rd in the south, Mickleham Rd in the west, JEN's northern service area boundary with AusNet Services, and Merri Creek in the east as shown in Figure 1-3.

[8] https://vpa.vic.gov.au/

[9] Growth Corridor Plan, Managing Melbourne Growth: Growth Areas Authority Nov 2012.

Figure 1-3 NDS Supply Area



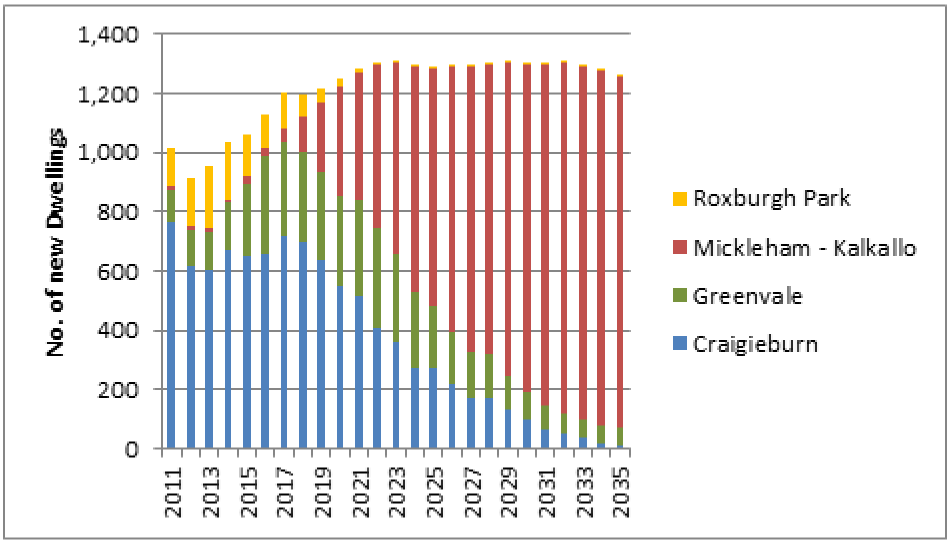
Growth in the corridor is now expanding further north and this has been evident with JEN now experiencing high volumes of customer connections and rapid load growth in the far north of its service area. Whilst the focus for the growth areas identified in our 2015 NDS were in Craigieburn, this latest NDS increases the focus on the new growth areas in Mickleham.

Hume City Council whose area contains both the Sunbury/Diggers Rest and Northern Growth Corridor has between 2 to 3 times the population growth of most other municipal areas. The population of Craigieburn in 2022 is 67,912 and this is forecast by Hume City Council to grow to 78,929 by 2041, an increase of 16.2%. This growth is due to additional dwellings in new housing lots and through infill and medium density development in existing residential areas. The population of Mickleham in 2022 is 17,671 and this is forecast to grow to 47,670 by 2041, an increase of 168.4%. This growth is predominantly due to new dwellings in housing lots in new subdivisions.

The development of new residential estates around the Mickleham, Greenvale and Craigieburn areas is driving the present rapid customer and load growth. Growth in the Northern Growth Corridor is predicted to remain strong until at least 2030 with new estates being developed around the Kalkallo and Mickleham as the available land around Craigieburn is being exhausted.

The Hume City Council[10] has predicted that approximately 1,250 new dwellings will be established within the areas of Roxburgh Park, Greenvale, Craigieburn and Mickleham each year until 2036 as shown in the Figure 1–4. The initial development in the area was around Craigieburn. This is now transitioning into the Mickleham area.

Figure 1–4: Forecast new dwellings Hume City Council



The major developments planned (or underway) within the NDS supply area include:

- Merrifield – commercial, residential and business park development sites in Mickleham;
- Botanical – Residential estate in Mickleham adjacent to the Annadale, Waratah and Trijena estates;
- Woodsong – Residential estate in Mickleham between Whites Lane and Mickleham Rd;
- Arena – Residential estate in Roxburgh Park;
- Fusion – A business park development along Donnybrook Rd in Mickleham;
- Highlands – Brookrise in Mickleham and other remaining residential development sites in Craigieburn;
- Amaroo – A business park development along Amaroo Rd in Craigieburn;
- Montview – Residential estate in Craigieburn
- 650 Hume Hwy – A business park development along the Hume Hwy in Craigieburn;
- Craigieburn West and Aston Estates – Residential developments bordering Craigieburn and Mickleham;
- True North and The Maples Estates – Residential developments in Greenvale;

[10] See http://forecast2.id.com.au/default.aspx?id=216&pg=5230&gid=610

- 680a Somerton Rd – mixed commercial and residential development in Greenvale;
- Austrak Business Park – Business Park redevelopment in Somerton;
- Ford Site Redevelopment – Business redevelopment of the assembly plant site in Campbellfield;
- Rex Rd Redevelopment – Business redevelopment of this industrial site in Campbellfield; and
- Various other smaller developments.

Several industrial and commercial businesses located along the Hume Highway in Somerton and Campbellfield lie within the former urban boundary. Vacant land is currently available in Somerton and Campbellfield for industrial and commercial development and JEN is seeing a steady stream of applications for new load, although this new load is offset by load decreases from decommissioned legacy industrial and commercial sites. Hence load growth in the brownfield development areas is likely to remain low (or marginally negative) until 2032 and will not be the main driver of net load growth for the supply area.

Growth in population (infill and greenfield residential development) and electrification is expected to have the largest contribution to growth in electricity demand in the supply area as shown in Table 1-1. Maximum demand for the supply area is expected to grow on average by 3.7% per annum during the next 10-year period (2025-34), however the level of growth is significantly skewed towards the northern part of the supply area where the bulk of greenfield sites are being developed. The expected increase in maximum demand is mainly driven by new customer connections across the area with vast areas of greenfield sites now under development or planned for development.

Table 1-1: Supply Area Resident Population[11]

Suburb	Actual 2021	Forecast 2041	Increase	% Increase (pa)
Mickleham	17,689	52,919	35,230	8.3%
Craigieburn	66,088	78,040	11,952	0.8%
Somerton / Campbellfield	5,332	5,988	656	0.5%
Meadow Heights	15,078	16,073	995	0.3%
Roxburgh Park	24,412	23,365	(1,047)	-0.2%
Greenvale / Yuroke	21,961	31,651	9,690	1.8%
Coolaroo	3,237	3,575	338	0.4%
TOTAL	**153,797**	**211,611**	**57,814**	**1.6%**

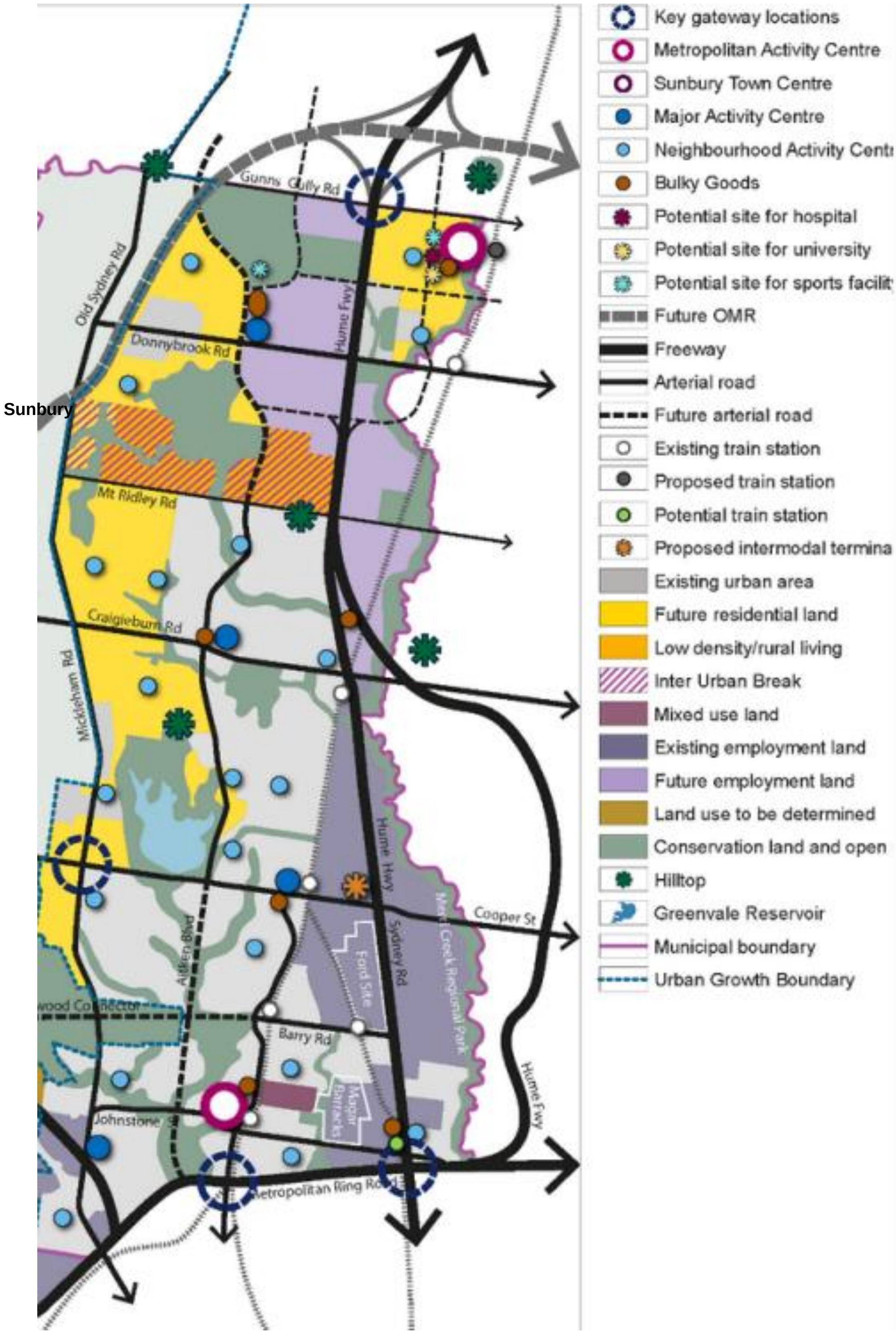
The largest increases in population are expected to occur in Mickleham and Craigieburn respectively, with the highest growth rate expected in the Mickleham area. Population growth in the supply area is predominantly being accommodated by new greenfield low and medium residential developments.

Development in the supply area is governed by the Hume[12] City Councils' Planning Scheme as illustrated in Figure 1–5.

[11] See https://forecast.id.com.au/hume.

[12] See https://planning-schemes.app.planning.vic.gov.au/static/1695670541404/pdf/2907411.pdf

Figure 1–5: Hume Planning Scheme strategic framework plan (Northern Growth Corridor)



Source: Hume Planning Scheme

The supply area is serviced by our Coolaroo (**COO**), Somerton (**ST**), Broadmeadows (**BD**) and AusNet's Kalkallo (**KLO**) zone substations by a network of 22 kV distribution feeders. The supply area currently services over 52,121

JEN electricity distribution customers. JEN relies on distribution feeders established out of KLO to supply much of the Mickleham area around Donnybrook Rd.

Table 1-2: Supply Area Electricity Distribution Customers[13]

Coolaroo (COO) Zone Substation	Actual 2022	Somerton (ST Zone Substation	Actual 2022	Broadmeadows (BD) Zone Substation	Actual 2022	Kalkallo (KLO) Zone Substation	Actual 2022
COO11	3,283	ST 11	3614	BD 01	141	KLO13	5057
COO12	3,502	ST 12	440	BD 02	1	KLO21	7
COO13	1	ST 13	505	BD 04	574	KLO22	5691
COO14	0	ST 14	170	BD 06	1	KLO23	1
COO21	1	ST 21	2	BD 08	832		
COO22	3,714	ST 22	4522	BD 09	687		
COO23	3,374	ST 23	154	BD 13	315		
COO24	3,572	ST 24	1	BD 14	2036		
		ST 31	1				
		ST 32	5780				
		ST 33	3681				
		ST 34	461				
17,447		**19,331**		**4,587**		**10,756**	
52,121							

Some of the existing zone substations and 22 kV distribution feeders supplying the area will not have sufficient capacity to meet this expected increase in maximum demand. A number of existing assets in the area are already (or forecast to be) highly utilised including two zone substations and nine 22 kV distribution feeders. Staged, targeted augmentations of the network are needed, to connect new customers and maintain current levels of supply reliability.

With the development of the new estates having HV underground feeders, the increased cable capacitance is expected to reduce performance of REFCL-protected feeders in the area. Network rearrangements will be needed to segregate overhead and underground networks so as to maintain REFCL performance at COO, a requirement of the Victorian bushfire safety regulations.

[13] Jemena Annual Regulatory Information Notice (RIN) 2021-22, tab 3.6.8.

1.3 Network Overview

The NDS supply area is currently serviced by:

- 4 x zone substations
    - 66/22 kV Somerton Zone Substation (**ST**)
    - 66/22 kV Coolaroo Zone Substation (**COO**)
    - 66/22 kV Broadmeadows Zone Substation (**BD**)
    - 66/22 kV Kalkallo Zone Substation (**KLO**) – AusNet owned
- 9 x JEN-owned 66kV sub-transmission lines forming 2 sub-transmission loops
    - SMTS-ST-SSS-SMTS
        - SMTS-ST
        - SMTS-SSS
        - SSS-ST
    - TTS-COO-VCO-BD-BMS-TTS
        - TTS-COO
        - TTS-BD
        - TTS-BMS
        - COO-VCO
        - BD-VCO
        - BD-BMS
- 18 x 11 kV distribution feeders (excluding spare CBs)
    - 12 ex ST – 11, 12, 13, 14, 21, 22, 23, 24, 31, 32, 33 and 34.
    - 8 ex COO – 11, 12, 13, 14, 21, 22, 23 and 24.
    - 8 ex BD – 01, 02, 04, 06, 08, 09, 13 and 14. *Note BD 03, 07, 10, 11, 15 and 16 are outside the southern boundary of the NDS supply area.*
    - 4 ex KLO[14] – 13, 21, 22 and 23. *Note, feeders for AusNet Services are excluded from the NDS supply area*.

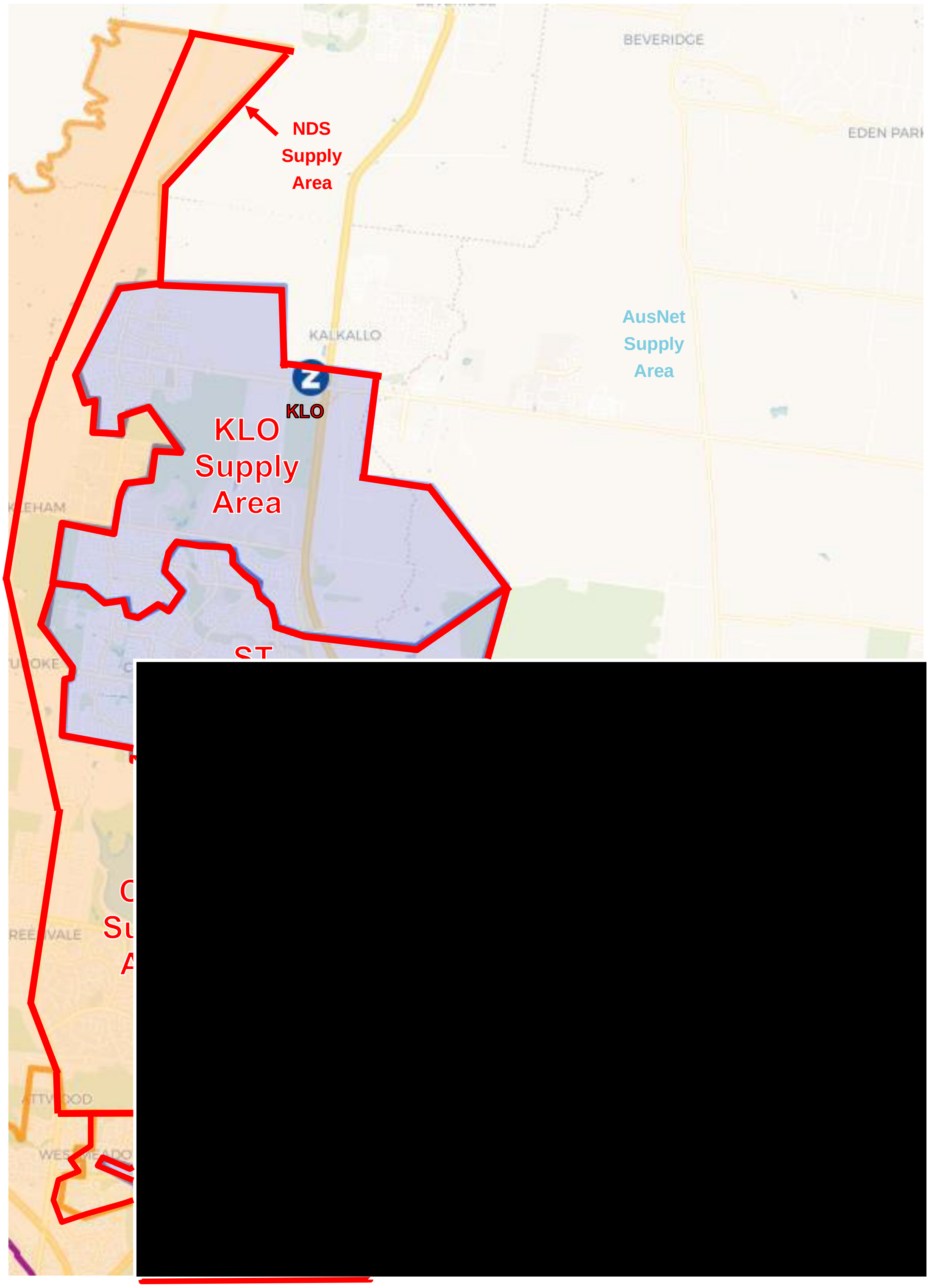
Single-line diagrams, network area maps and details of the existing network are outlined below.

[14] 'KLO' is AusNet's Kalkallo Zone Substation which supplies four 22 kV distribution feeders into the supply area.

1.3.1 Zone substation network

The supply boundaries of the zone substations contained within the NDS supply area (shaded) are shown in Figure 1-6, showing the location of the zone substations and their sub-transmission lines (purple).

Figure 1-6 Zone Substation Boundaries



There is currently only one zone substation located in the northern high-growth section of the NDS supply area, being KLO. The zone substation closest to KLO that provides remote support for the growth areas is ST, located towards the southern section of the NDS supply area. CBN is a site reservation for a proposed future Craigieburn zone substation located midway between KLO and ST. BD and ST support the loads in the establish areas in the southern section of the NDS supply area.

1.3.1.1 Somerton (ST) zone substation

ST is a fully developed indoor zone substation located on the south-eastern side of the Hume Hwy and the corner of Patullos Lane, supplied from South Morang Terminal Station (SMTS). ST comprising three 66/22 kV 20/33 MVA transformers and three 22 kV buses supplying twelve 22 kV distribution feeders. Within the NDS supply area, ST supplies both the residential areas of Craigieburn, Roxburgh Park, and Greenvale to the west of the Hume Highway, and a mixture of industrial and commercial load predominantly located on either side of the highway in the Somerton and Campbellfield areas. ST Zone Substation currently supplies over 19,331 customers with several major customers including Craigieburn Shopping Centre, Australian Tube Mills, Austrak Business Park and Notes Printing Australia. The ST single line diagram is shown in Figure 1-7 with its aerial view. The zone substation has no 66 kV line incomer circuit breakers, such that in the event of a line fault, a transformer will also be taken out of service until it can be manually restored. ST has 6 MVAr and 8 MVAr capacitor banks with provision for a third capacitor bank in its ultimate design. ST has no spare 22 kV circuit breakers for additional feeders, although the spare capacitor bank CB could be utilised as an additional feeder in future. The station also has a neutral earthing resistor (NER) to reduce the 22 kV line to ground fault levels in the ST supply area.

Figure 1-7 ST Single Line Diagram

[redacted]

Figure 1-8 ST Aerial View

1.3.1.2 Coolaroo (COO) zone substation

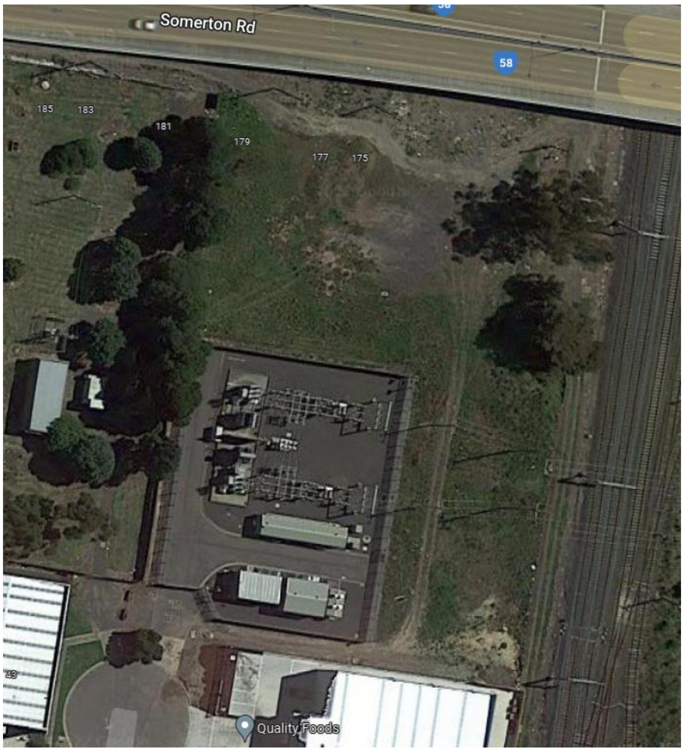
COO was established in 2008 as a 20/33 MVA single transformer zone substation to cater for load growth in the Roxburgh Park area. Installation of a second 20/33 MVA transformer and two new 22 kV feeders at COO was completed in late 2012. Despite the installation of the second transformer, which was also used to offload ST, rapid load growth in the area has meant the summer demand at COO is already marginally above its N-1 rating. COO was designed as a two-transformer ultimate zone substation. The installation of a third transformer is not feasible due to earth grid design issues associated with a main water pipeline located in the vacant land north of the zone substation. The zone substation has 66 kV line incomer circuit breakers, such that in the event of a line fault, a transformer will not be taken out of service.

COO is located in Zakwell Ct, Coolaroo and is bounded by Somerton Rd and the Craigieburn railway line. COO comprises two 66/22 kV 20/33 MVA transformers and two 22 kV buses supplying six 22 kV feeder lines. COO supplies more than 17,447 customers in the areas of Coolaroo, Meadow Heights, Greenvale, Roxburgh Park and Oaklands Junction. Within the NDS supply area it services the suburbs of Meadow Heights, Roxburgh Park, Greenvale and Coolaroo. COO is supplied from Thomastown Terminal Station (**TTS**).

Figure 1-9 shows the single line diagram of COO and its aerial view.

[redacted]

Figure 1-10 COO Aerial View



With some open paddocks and overhead 22 kV lines within its supply area, COO is at a higher bushfire risk than most of JEN's supply area. JEN was required to install Rapid Earth Fault Current Limiters (REFCL) at COO by 1 May 2023 to comply with the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013 and avoid penalty under the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017. REFCL regulation applies to all feeders that were normally supplied from COO on 1 May 2016. A project to install a high-performance REFCL has been completed with flexibility to enable it for either 22 kV COO bus. The high performance REFCL settings for bushfire mitigation will normally be applied on the No. 1 22 kV Bus supplying COO11 and COO12. The No. 2 22 kV bus has the base-level REFCL settings normally applied, with the 22 kV bus tie CB normally open on days of total fire ban

Following the REFCL installation and distribution feeder rearrangements (completed in 2023), COO is close to the capacitive current (**Ico**) design limit of the REFCL, so new HV underground cable on COO needs to be minimised. The Ico limit determines the maximum threshold at which the REFCL is still able to achieve its required performance under the Victorian bushfire safety regulations. Therefore, new developments will need to be connected to KLO or ST distribution feeders, except where it is only a very small amount of cable (e.g., from pole to nearby kiosk) or where there is no other alternative (e.g., road widening requiring overhead line to be relocated underground where there is no space for it to remain as an overhead line).

1.3.1.3 Broadmeadows (BD) zone substation

BD is a fully developed 66/22 kV zone substation with two 20/30 MVA transformers and two 20/33 MVA transformers located on the corner of Barry Rd and Maffra St in in Coolaroo. BD has three 22 kV buses supplying fourteen 22 kV distribution feeders. BD supplies the suburbs of Broadmeadows, Meadow Heights, Jacana and Campbellfield. For those BD feeders supporting the NDS supply area, BD supplies more than 4,587 customers in the suburbs of Campbellfield and Coolaroo. BD is supplied from TTS. Figure 1-11 shows the single line diagram of BD.

Figure 1-11 BD Single Line Diagram

[redacted]

Figure 1-12 BD Aerial View

1.3.2 Sub-transmission network

Three 66 kV sub-transmission networks service the area, one from TTS (for BD and COO), and two from SMTS (for ST and KLO), as shown in Figure 1-13.

Figure 1-13: 66kV Sub-transmission Lines in the Supply Area - Schematic

[redacted]

1.3.2.1 SMTS-ST-SSS-SMTS

The SMTS-ST 66 kV line runs along O'Hearns Road and passes by SSS en route to ST. It then runs along the east side of the Hume Highway from O'Hearns Road to Patullos Lane. ST is an indoor zone substation located on the corner of Hume Highway and Patullos Lane. Entry of the 66 kV line into ST is via wall bushings located on the south wall of the zone substation.

The SMTS-SSS 66 kV line approaches sub SSS from the south along the east side of the Hume Highway. SSS-ST is a high capacity 66 kV line, built as a dual conductor line with conductors running in parallel. It predominately runs from SSS to ST along the west side of the Hume Highway, crossing at Patulous Lane and connecting into the ST via wall bushings mounted on the north wall of the substation.

The existing sub-transmission system is shown schematically in Figure 1-14.

Figure 1-14: SMTS-ST-SSS-SMTS 66kV Sub-transmission Loop

[redacted]

Somerton Power Station is a gas-turbine power station connected into SSS. It has 160 MW in total generating capacity. SSS does not supply any JEN load customers in the area, but serves as a switching substation for connection of the Somerton Power Station into the 66 kV sub-transmission network. There is no network support agreement currently in place between JEN and Somerton Power Station to alleviate any network limitations.

1.3.2.2 TTS-COO-VCO-BD-BMS-TTS

The TTS-COO 66 kV line runs along much of the same route on double circuit poles with SMTS-SSS which supports ST. Entry of the line into COO is by an overhead 66 kV line via Somerton Road.

The TTS-BD 66 kV line runs along an easement to Mahoneys Road, then up Hume Highway to Barry Road along a single circuit 66 kV overhead pole line. Entry of the line into BD is by an overhead 66 kV line.

The TTS-BMS 66 kV line runs along an easement to the Western Ring Road, sharing much of its route to Camp Road on double circuit poles with AusNet Services' SMTS-KMS-SMR 66 kV line which supports KLO. Entry of the line into BMS is by an overhead 66 kV line.

The existing sub-transmission system is shown schematically in Figure 1-15.

Figure 1-15: TTS- COO-VCO-BD-BMS-TTS 66kV Sub-transmission Loop

[redacted]

1.3.3 HV distribution feeder network

JEN's 22 kV distribution feeder network for the NDS supply area is illustrated schematically in Figure 1-16.

Multiple 22 kV inter-feeder tie points exist between JEN feeders on KLO, COO, ST, and BD (via feeders KLO22 – ST 11, ST 11, ST 22 & ST 33; ST 24 – BD 09; ST 23 – BD 01; ST 34 – BD 13; ST 13 – BD 08; ST 21 & ST 32 – COO22 & COO24).

Note: Ties with COO Bus No.1 feeders are only available under contingency conditions due to COO being a REFCL zone substation.

Figure 1-16: 22 kV Distribution Feeders

[redacted]

1.4 Non-network alternatives

The NER requires us to consider non-network and standalone power systems (SAPS) solutions for addressing identified limitations on our network. In developing this NDS, we have considered the possibility of credible non-network or SAPS solutions, for meeting each of the existing and emerging network capacity limitations identified within the supply area.

Non-network and SAPS solutions could be delivered through embedded generation, storage, or demand-side management programs (or combination thereof), to defer or reduce in scope, traditional network augmentation solutions. Such solutions need to have a sufficient number of proponents participating, to provide the aggregate level of dispatchable capacity needed, to defer an augmentation by at least one year. This could then address the identified capacity limitations, and avoid supply interruptions or asset overload damage which may otherwise result without adequate network support.

Demand management solutions are targeted at reducing the peak demand by reducing customer load. This includes solutions such as direct load control (including for example, air-conditioning, pool pumps and electric vehicle charging), or customer behavioural demand response programs. By comparison, embedded generation and/or storage solutions are targeted at supplying the peak demand by offsetting part of the customers' load using local generation sources. This includes dispatchable blocks of embedded generators and/or energy storage systems (including for example, virtual power plants, community storage, standby/grid connected generation).

The aim when defining potential credible non-network and SAPS options, is to test whether non-network or SAPS solutions (or combination of) is a viable way to avoid or reduce the scale of a network investment, in a way that efficiently addresses the identified need. The criteria we use to assess the potential credibility of non-network or SAPS solutions includes:

- **Addressing the identified need**: being able to reduce or eliminate the supply reliability risk (EUE) associated with the identified need.
- **Technically feasible**: there being no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or potentially better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

We intend to pursue a blend of prudent, targeted investments in network and non-network solutions to reduce EUE within the NDS supply area, consistent with NER clause 6.5.7. This approach provides us with greater option value (in some cases) to manage uncertainty in our forecasts of maximum demand growth. As such, for each of the major solutions identified in the preferred network development plan of this NDS, we intend to consult the market (through the RIT-D process) to identify credible non-network or SAPS solutions.

Given the needs for non-network solutions for this NDS are known, we are yet to identify (from the market) credible non-network solutions for each limitation. We intend to fund any identified preferred option non-network solutions through capex to opex substitution during the regulatory control period, rather than request step changes to our operational expenditure regulatory allowance.

Notwithstanding our approach to seeking efficient solutions to project augmentation, we have undertaken a high-level assessment of non-network options by considering the benefits of deferring expenditure by one year against a plausible alternative of procuring capacity from the market based on recent RIT-D responses. Applying this methodology to distributed storage solutions, we determined that the installed costs[15] of $255.3 million[16] is greater than the $51.6 million installed costs of the preferred network option. Furthermore, applying this methodology to the lowest-cost demand response solution, we determined that the costs of $5.1 million pa[17] is also greater than the network augmentation deferral benefit of $2.7 million pa[18]. Therefore, the non-network options are not the preferred approach based on program-wide network benefits alone.

[15] Table B.8 "Storage current cost data by source, total cost basis", from the CSIRO 2023-24 GenCost Report, located at https://www.csiro.au/en/research/technology-space/energy/GenCost.

[16] Installed cost of $500/kWh x $489 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $255.3 million.

[17] Dispatch cost of $10/kWh x $489 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $5.1 million pa.

[18] Preferred network option cost of 51.6 million present value of capital and O&M costs x 5.18% discount rate = $2.7 million pa.

2. Identified Need

There are two key drivers for an asset management intervention in the NDS supply area.

- The first driver relates to existing and emerging asset utilisation limitations associated with maximum demand growth (**reliability**).
- The second driver relates to the management of underground cable lengths on Rapid Earth Fault Current Limited (**REFCL**) protected feeders to maintain the required REFCL performance at COO (**Victorian bushfire safety regulations compliance**).

2.1 Network Utilisation

Maximum demand for the supply area is expected to grow on average by 4.0% per annum during the next 10-year period (2025-34) based on underlying growth within the distribution network. The expected increase in maximum demand is mainly driven by population growth from residential infill and greenfield estate development, and electric vehicle usage and electrification of gas across the area, with some major customer developments.

Some of the existing zone substations and 22 kV distribution feeders supplying the area, will not have sufficient capacity to meet this expected increase in maximum demand. A number of existing assets in the area are already (or forecast to be) highly utilised including two zone substations and nine 22 kV distribution feeders. Staged, targeted augmentations of the network are needed to connect new customers and maintain current levels of supply reliability.

2.1.1 Network Ratings

This section details the network capacity ratings that are available for customers to use during system normal (**N**) conditions and single contingency (**N-1**) conditions with one network asset out of service (forced or planned outage), for summer (worst case) and winter (best case) seasons. Table 2-1 present the ratings of zone substations servicing the supply area.

Table 2-1: Zone Substation Ratings (MVA)

Zone Substation	Summer (N)	Winter (N)	Summer (N-1)	Winter (N-1)
ST	95.2	95.2	79.7	89.3
BD	123.0	123.0	123.7	125.1
COO	46.5	47.6	38.0	39.6

Table 2-2 present the ratings of sub-transmission lines servicing the supply area.

Table 2-2: Sub-transmission Ratings (MVA)

Sub-transmission Network	Summer	Winter	Line Section
SMTS-ST-SSS	**190**	**200**	**Overall N Rating**
	117	**126**	**Overall N-1 Rating**
	117	126	SMTS-SSS
	117	126	SMTS-ST
	142	182	SSS-ST
TTS-COO-VCO-BD-BMS	**280**	**300**	**Overall N Rating**
	196	**217**	**Overall N-1 Rating**
	101.7	104.6	TTS-BMS
	117.2	126.3	TTS-BD
	101.7	112.6	TTS-COO
	89.7	93.1	BMS-BD
	90.3	98.0	COO-VCO
	89.7	93.1	BD-VCO

Table 2-3 presents the ratings of 22 kV distribution feeders servicing the NDS supply area.

Table 2-3: 22kV Distribution Feeder Ratings (MVA)

Feeder	Summer	Winter	Feeder	Summer	Winter
BD 01	14.3	14.3	KLO13	14.3	14.5
BD 02	22.5	22.5	KLO21	14.3	14.5
BD 04	11.6	11.6	KLO22	14.3	14.3
BD 06	22.5	22.5	KLO23	14.3	14.3
BD 08	11.6	11.6	ST 11	22.5	22.6
BD 09	13.1	13.1	ST 12	14.3	14.6
BD 13	12.0	12.0	ST 13	14.3	14.3
BD 14	12.0	12.0	ST 14	14.3	14.3
COO11	10.9	10.9	ST 21	14.3	14.3
COO12	14.3	14.3	ST 22	22.5	22.5

Feeder	Summer	Winter
COO13	12.0	12.0
COO14	12.0	12.0
COO21	14.3	14.3
COO22	12.0	12.0
COO23	14.3	14.3
COO24	12.2	12.2

Feeder	Summer	Winter
ST 23	22.5	22.5
ST 24	14.3	14.3
ST 31	22.5	22.5
ST 32	12.4	12.6
ST 33	12.5	12.5
ST 34	14.3	14.3

2.1.2 Historical Maximum Demand

Table 2-4 and Table 2-5 present the historical actual summer maximum demand on our assets in the area. Values highlighted in red exceed the (N-1) cyclic rating and **bold red** exceed the (N) rating, noting that 2021 was a mild ambient temperature (and hence an abnormally low maximum demand) summer.

Table 2-4: Actual Historical Summer Maximum Demand (MVA)

Network Asset	N Rating	N-1 Rating	2020	2021	2022	2023
ST	**95.2**	**79.7**	76.4	65.6	71.1	70.4
BD	**123**	**123**	72.4	64.0	68.0	70.5
COO	**46.5**	**38.0**	43.7	40.8	44.3	37.0
SMTS-ST-SSS	**190**	**117**	76.4	65.6	71.1	70.4
TTS-COO-VCO-BD-BMS	**280**	**196**	170	157	169	166

Table 2-5: Distribution Feeder Actual Historical Summer Maximum Demand (MVA)

Feeder	Rating	2020	2021	2022	2023
BD 01	**14.3**	5.8	7.2	7.3	7.0
BD 02	**22.5**	1.6	0.6	0.8	0.0
BD 04	**11.6**	3.4	3.1	3.5	3.0
BD 06	**22.5**	1.3	0.8	0.3	0.0
BD 08	**11.6**	8.5	8.5	8.3	8.3
BD 09	**13.1**	5.0	4.6	4.2	11.5
BD 13	**12.0**	7.3	7.5	7.7	7.8
BD 14	**12.0**	7.2	6.7	7.4	8.3
COO11	**10.9**	12.2	9.5	10.4	6.0
COO12	**14.3**	6.6	4.8	5.3	4.2
COO13	**12.0**	7.5	6.4	6.6	5.4
COO14	**12.0**	9.0	8.2	7.6	6.8
COO21	**14.3**	8.7	7.5	9.8	4.9
COO22	**12.0**	10.3	10.0	10.2	6.1
COO23	**14.3**	0.0	0.0	0.0	10.1
COO24	**12.2**	0.0	0.0	0.0	7.8

Feeder	Rating	2020	2021	2022	2023
KLO13	**14.3**	5.3	5.7	8.2	10.0
KLO21	**14.3**	1.0	1.1	2.2	2.1
KLO22	**14.3**	6.8	7.5	9.0	9.8
KLO23	**14.3**	0.0	0.6	1.0	1.2
ST 11	**22.5**	12.0	13.5	14.4	16.2
ST 12	**14.3**	8.2	6.5	7.0	7.0
ST 13	**14.3**	7.7	7.3	7.8	7.4
ST 14	**14.3**	7.7	7.4	7.5	6.7
ST 21	**14.3**	1.4	1.2	1.3	1.2
ST 22	**22.5**	13.3	11.6	11.6	12.1
ST 23	**22.5**	9.4	9.1	7.6	7.5
ST 24	**14.3**	1.9	2.4	2.4	2.4
ST 31	**22.5**	2.3	2.3	2.8	2.4
ST 32	**12.4**	9.1	8.4	10.0	10.7
ST 33	**12.5**	11.6	11.1	10.6	11.2
ST 34	**14.3**	9.2	8.8	9.0	9.8

2.1.3 Maximum Demand Forecast

This section presents the maximum demand forecast over the next 10 years for the NDS supply area, taking into account new loads, underlying growth, and the impacts of Consumer Energy Resources (CER) and the Victorian Government's gas substitution road map.[19] The maximum demand forecasts are developed under different ambient temperature conditions, designated by a Probability of Exceedance (**PoE**), using internally prepared bottom-up forecasts which are reconciled to externally prepared top-down econometric forecasts[20].

Table 2-6 presents the 10% PoE summer maximum demand forecast for the forward 10-year planning period. Values highlighted and are an identified network limitation with red exceeding the (N-1) rating and **bold red** exceeding the (N) rating. Both ST and COO are forecast to exceed their N and N-1 ratings within the 10-year period.

19 https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap

20 Refer to Section 2.3 of JEN DAPR https://www.jemena.com.au/siteassets/asset-folder/documents/electricity/2023-distribution-annual-planning-report.pdf

Table 2-6: 10% PoE Summer Maximum Demand Forecast (MVA) - Do Nothing

Network Asset	N Rating	N-1 Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ST	**95.2**	**79.7**	80.7	85.3	90.6	95.0	**98.2**	**101**	**103**	**106**	**109**	**111**
BD	**123**	**123**	75.4	78.7	81.7	83.7	84.3	85.4	86.7	88.0	89.3	90.2
COO	**46.5**	**38.0**	**46.8**	**48.3**	**49.5**	**50.3**	**50.9**	**52.0**	**53.2**	**54.5**	**55.7**	**56.7**
SMTS-ST-SSS	**190**	**117**	80.7	85.3	90.6	95.0	98.2	101	103	106	109	111
TTS-COO-VCO-BD-BMS	**280**	**196**	185	190	194	197	199	201	205	208	212	215

Table 2-7 presents the 10% PoE winter maximum demand forecast for the forward 10-year planning period. Values highlighted and are an identified network limitation with red exceeding the (N-1) rating and **bold red** exceeding the (N) rating.

Table 2-7: 10% PoE Winter Maximum Demand Forecast (MVA) - Do Nothing

Network Asset	N Rating	N-1 Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ST	**95.2**	**89.3**	82.0	87.9	94.0	**99.0**	**102**	**105**	**107**	**109**	**111**	**114**
BD	**123**	**125**	78.4	83.1	87.1	89.6	90.6	91.7	92.8	93.8	94.8	95.9
COO	**47.6**	**39.6**	34.7	37.1	38.9	40.1	41.0	42.1	42.9	43.9	44.9	45.9
SMTS-ST-SSS	**200**	**126**	82.0	88	94	99	102	105	107	109	111	114
TTS-COO-VCO-BD-BMS	**300**	**217**	177	185	192	196	198	200	203	204	207	209

Table 2-8 presents the distribution feeder 10% PoE summer maximum demand forecast for the forward 10-year planning period. Values highlighted in in **bold red** exceed 100% of the rating (i.e., exceed the N rating) and are an identified network limitation.

Table 2-8: Distribution Feeder 10% PoE Summer Maximum Demand Forecast (MVA) - Do Nothing

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
BD 01	**14.3**	7.7	9.2	10.5	11.0	11.1	11.2	11.4	11.6	11.7	11.8
BD 02	**22.5**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BD 04	**11.6**	6.3	6.6	7.0	7.3	7.4	7.6	7.8	8.0	8.2	8.3
BD 06	**22.5**	0.0	0.8	1.9	2.7	2.7	2.8	2.8	2.8	2.9	2.9
BD 08	**11.6**	9.0	9.5	9.9	10.0	10.1	10.2	10.3	10.5	10.6	10.8
BD 09	**13.1**	4.2	4.4	4.5	4.6	4.6	4.6	4.7	4.8	4.9	4.9
BD 13	**12.0**	8.1	8.2	8.3	8.5	8.5	8.6	8.7	8.9	9.0	9.1
BD 14	**12.0**	9.1	9.0	9.0	9.0	9.1	9.2	9.3	9.5	9.6	9.7
COO11	**10.9**	5.5	5.6	5.7	5.8	5.8	5.9	6.1	6.2	6.4	6.5
COO12	**14.3**	6.7	7.5	8.2	8.3	8.4	8.6	8.8	9.0	9.2	9.3
COO13	**12.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COO14	**12.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COO21	**14.3**	4.6	4.6	4.6	4.6	4.6	4.7	4.7	4.8	4.9	4.9
COO22	**12.0**	9.1	9.1	9.2	9.2	9.3	9.5	9.7	9.9	10.2	10.3
COO23	**14.3**	13.8	**16.1**	**17.8**	**18.9**	**19.5**	**20.3**	**20.9**	**21.6**	**22.3**	**22.9**
COO24	**12.2**	10.3	10.2	10.2	10.3	10.4	10.6	10.8	11.1	11.3	11.5
KLO13	**14.5**	11.8	**15.0**	**16.3**	**16.9**	**17.2**	**17.9**	**18.6**	**19.5**	**20.3**	**21.1**
KLO21	**14.5**	11.2	13.9	**16.5**	**18.6**	**19.9**	**21.4**	**22.3**	**23.2**	**24.2**	**25.2**
KLO22	**14.3**	10.0	13.0	**16.0**	**19.2**	**21.3**	**23.5**	**25.8**	**27.9**	**30.1**	**31.9**
KLO23	**14.3**	1.1	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4
ST 11	**22.6**	13.9	14.6	15.6	15.9	16.2	16.7	17.2	17.8	18.4	18.9
ST 12	**14.6**	13.6	**16.1**	**19.3**	**22.4**	**25.2**	**27.6**	**29.4**	**30.8**	**32.2**	**33.5**
ST 13	**14.3**	8.8	9.7	10.6	11.0	11.1	11.3	11.6	11.8	12.1	12.3
ST 14	**14.3**	7.6	7.5	7.5	8.2	9.0	9.9	10.1	10.3	10.5	10.7
ST 21	**14.3**	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ST 22	**22.5**	14.6	17.6	20.7	**23.0**	**24.7**	**25.7**	**26.8**	**28.0**	**29.2**	**30.3**
ST 23	**22.5**	11.0	12.1	13.4	13.7	13.8	14.0	14.2	14.5	14.7	14.9
ST 24	**14.3**	7.0	7.3	7.7	8.2	8.2	8.3	8.4	8.5	8.6	8.7
ST 31	**22.5**	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8
ST 32	**12.6**	8.0	8.2	8.3	8.4	8.5	8.9	9.3	9.7	10.1	10.5
ST 33	**12.5**	9.9	9.9	10.0	10.0	10.1	10.3	10.6	10.8	11.1	11.3
ST 34	**14.3**	12.0	12.5	12.8	13.0	13.1	13.4	13.7	14.0	14.3	**14.6**

Table 2-9 presents the distribution feeder 10% PoE winter maximum demand forecast for the forward 10-year planning period. Values highlighted in in **bold red** exceed 100% of the rating (i.e., exceed the N rating) and are an identified network limitation.

Table 2-9: Distribution Feeder 10% PoE Winter Maximum Demand Forecast (MVA) - Do Nothing

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
BD 01	**14.3**	8.0	9.8	11.4	12.0	12.1	12.3	12.4	12.6	12.7	12.9
BD 02	**22.5**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BD 04	**11.6**	5.7	6.1	6.6	7.0	7.2	7.4	7.6	7.8	8.0	8.2
BD 06	**22.5**	0.0	0.8	1.9	2.7	2.8	2.9	3.0	3.0	3.1	3.1
BD 08	**11.6**	10.2	10.7	11.1	11.3	11.3	11.3	11.3	11.3	11.3	11.4
BD 09	**13.1**	4.9	5.3	5.6	5.6	5.7	5.8	5.9	5.9	6.0	6.1
BD 13	**12.0**	9.2	9.6	9.9	10.1	10.2	10.4	10.5	10.6	10.7	10.9
BD 14	**12.0**	9.2	9.3	9.4	9.5	9.6	9.8	9.9	10.0	10.1	10.2
COO11	**10.9**	5.1	5.4	5.5	5.7	5.8	5.9	6.1	6.3	6.4	6.6
COO12	**14.3**	7.5	8.7	9.6	9.9	10.1	10.4	10.7	10.9	11.2	11.5
COO13	**12.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COO14	**12.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
COO21	**14.3**	7.4	7.4	7.4	7.4	7.4	7.4	7.5	7.5	7.5	7.5
COO22	**12.0**	7.9	8.2	8.4	8.5	8.7	8.9	9.2	9.4	9.6	9.9
COO23	**14.3**	10.2	12.8	**14.8**	**16.2**	**17.1**	**18.1**	**18.7**	**19.4**	**20.1**	**20.7**

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
COO24	**12.2**	8.8	8.9	9.1	9.3	9.5	9.7	10.0	10.2	10.5	10.7
KLO13	**14.5**	9.2	12.1	13.4	14.1	**14.6**	**15.5**	**16.3**	**17.0**	**17.8**	**18.5**
KLO21	**14.5**	12.2	**15.6**	**18.9**	**21.7**	**23.7**	**25.8**	**27.1**	**28.3**	**29.6**	**30.8**
KLO22	**14.3**	9.7	13.0	**16.4**	**20.0**	**22.6**	**25.4**	**28.0**	**30.4**	**32.8**	**34.9**
KLO23	**14.3**	1.4	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.9
ST 11	**22.6**	17.3	18.6	20.2	21.0	21.5	22.3	**23.1**	**24.0**	**24.8**	**25.7**
ST 12	**14.6**	13.2	**16.0**	**19.7**	**23.3**	**26.7**	**29.7**	**31.8**	**33.4**	**35.1**	**36.6**
ST 13	**14.3**	10.0	11.2	12.3	12.6	12.7	12.8	12.9	13.1	13.2	13.3
ST 14	**14.3**	7.0	7.0	7.0	7.7	8.4	9.2	9.2	9.3	9.3	9.4
ST 21	**14.3**	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
ST 22	**22.5**	15.1	18.8	22.4	**25.3**	**27.4**	**28.7**	**30.0**	**31.4**	**32.8**	**34.3**
ST 23	**22.5**	11.0	12.4	13.9	14.3	14.5	14.7	15.0	15.2	15.4	15.6
ST 24	**14.3**	7.4	7.8	8.3	8.8	8.8	8.8	8.8	8.8	8.7	8.7
ST 31	**22.5**	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
ST 32	**12.6**	7.3	7.7	7.9	8.2	8.5	9.0	9.5	9.9	10.3	10.8
ST 33	**12.5**	9.0	9.2	9.5	9.6	9.8	10.1	10.4	10.6	10.9	11.2
ST 34	**14.3**	13.2	14.0	14.2	**14.4**	**14.5**	**14.6**	**14.8**	**14.9**	**15.1**	**15.2**

Several 22 kV feeders are forecast to exceed their N rating within the 10-year planning period including COO23, KLO13, KLO21, KLO22, ST 11, ST 12, ST 22, and ST 34.

2.2 REFCL Performance

With the development of new greenfield estates having HV underground feeders, the increased cable capacitance is expected to deteriorate the performance of Rapid Earth Fault Current Limiter (REFCL)-protected feeders in the area, that is, feeders supplied by the COO REFCL zone substation. Network rearrangements are already being undertaken and will continue to be needed to segregate overhead and underground networks so as to maintain REFCL performance. Maintaining REFCL performance means limiting the amount of new HV underground cable connected to REFCL-protected feeders.

Table 2-10 presents the forecast levels of cable capacitance current (Ico) expected at COO zone substation over the next 10-years based on a “Do nothing” approach. The increases in Ico are due to the installation of new HV underground cable in the COO supply area. Values in **bold red** indicate the level of Ico is forecast to exceed the design rating of the REFCL.

Table 2-10: Existing and forecast Ico at COO (Amps) - Do Nothing

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
COO11	-	68	70	72	73	75	77	78	80	82	83
COO12	-	43	45	46	48	50	52	53	55	57	58
COO13	-	0	0	0	0	0	0	0	0	0	0
COO14	-	0	0	0	0	0	0	0	0	0	0
BUS No.1	**120**	**111**	**115**	**118**	**122**	**125**	**129**	**132**	**135**	**139**	**142**
COO21	-	2	2	2	2	2	2	2	2	2	2
COO22	-	106	109	112	115	118	121	124	127	131	134
COO23	-	104	112	121	130	139	149	160	170	181	193
COO24	-	64	64	64	64	64	64	64	64	64	64
BUS No.2	**300**	**276**	**287**	**299**	**311**	**323**	**336**	**350**	**364**	**378**	**393**

The limits of Ico on each bus are exceeded in 2028 for the high performance REFCL Bus No.1, and 2028 for the base performance REFCL Bus No.2.

2.3 Summary of Network Limitations

This NDS will assess the technical and economic viability of solutions to alleviate the network utilisation issues. A summary of credible solutions is presented in Table 2-11 that address the identified limitations. Further details and diagrams of the scope of the solutions is provided in the Appendices.

Table 2-11: Summary of identified network limitations and possible options

Network Asset	Limitation	From	Screening of credible network options to address the need[21]
COO 22 kV Bus No.1	REFCL safety	2028	Coolaroo No.1 bus cable transfers
COO 22 kV Bus No.2	REFCL safety	2028	Coolaroo No.2 bus feeders
COO	N-1 Overload N Overload	Existing 2025	Coolaroo No.2 bus feeders BESS and/or demand management in COO 22 kV distribution network
ST	N-1 Overload N Overload	2025 2028	Load transfers from ST 24 to BD 09 – close 17960, open ST 24 CB[22] Augment feeder BD0-008 Establish new Craigieburn (CBN) zone substation - zone substation works & Establish new Craigieburn (CBN) zone substation - HV feeder works New 66/22 kV zone substation at GVE & New 22 kV feeders at GVE Load transfers from ST to CBN (post CBN) Load transfers from ST to GVE via COO (post GVE) BESS and/or demand management in ST 22 kV distribution network
COO23	Overload	2026	Coolaroo No.2 bus feeders BESS and/or demand management in COO 23 22 kV distribution network
KLO13	Overload	2026	New feeder KLO-023 BESS and/or demand management in KLO 13 & KLO 21 22 kV distribution networks
KLO21	Overload	2026	
KLO22	Overload	2027	New feeder from ST or KLO Establish new Craigieburn (CBN) zone substation - zone substation works & Establish new Craigieburn (CBN) zone substation - HV feeder works New 66/22 kV zone substation at GVE & New 22 kV feeders at GVE Load transfers from ST & KLO feeders to CBN (post CBN) Load transfers from ST & KLO feeders to GVE & via COO (post GVE) Augment feeder BD0-008 BESS and/or demand management in ST & KLO 22 kV distribution networks
ST 11	Overload	2031	
ST 12	Overload	2026	
ST 22	Overload	2028	
ST 34	Overload	2028	

The effectiveness of each solution to address an identified need is evaluated within this NDS by comparing its costs and benefits against the status quo (do nothing), used as a reference base case.

Where multiple potential solutions are indicated above to address an identified limitation, those solutions are separated into different options in this NDS for further comparative technical and economic evaluation.

[21] Refer to section 2.4 for details on non-network alternatives.

[22] This load transfer applied for all options, including do nothing as it assumed to have zero cost.

2.4 Non-network alternatives

The NER requires us to consider non-network and standalone power systems (SAPS) solutions for addressing identified limitations on our network. In developing this NDS, we have considered the possibility of credible non-network or SAPS solutions, for meeting each of the existing and emerging network capacity limitations identified within the supply area.

Non-network and SAPS solutions could be delivered through embedded generation, storage, or demand-side management programs (or combination thereof), to defer or reduce in scope, traditional network augmentation solutions. Such solutions need to have a sufficient number of proponents participating, to provide the aggregate level of dispatchable capacity needed, to defer an augmentation by at least one year. This could then address the identified capacity limitations, and avoid supply interruptions or asset overload damage which may otherwise result without adequate network support.

Demand management solutions are targeted at reducing the peak demand by reducing customer load. This includes solutions such as direct load control (including for example, air-conditioning, pool pumps and electric vehicle charging), or customer behavioural demand response programs. By comparison, embedded generation and/or storage solutions are targeted at supplying the peak demand by offsetting part of the customers' load using local generation sources. This includes dispatchable blocks of embedded generators and/or energy storage systems (including for example, virtual power plants, community storage, standby/grid connected generation).

The aim when defining potential credible non-network and SAPS options, is to test whether non-network or SAPS solutions (or combination of) is a viable way to avoid or reduce the scale of a network investment, in a way that efficiently addresses the identified need. The criteria we use to assess the potential credibility of non-network or SAPS solutions includes:

- **Addressing the identified need**: being able to reduce or eliminate the supply reliability risk (EUE) associated with the identified need.
- **Technically feasible**: there being no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or potentially better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

We intend to pursue a blend of prudent, targeted investments in network and non-network solutions to reduce EUE within the NDS supply area, consistent with NER clause 6.5.7. This approach provides us with greater option value (in some cases) to manage uncertainty in our forecasts of maximum demand growth. As such, for each of the major solutions identified in the preferred network development plan of this NDS, we intend to consult the market (through the RIT-D process) to identify credible non-network or SAPS solutions.

Given the needs for non-network solutions for this NDS are known, we are yet to identify (from the market) credible non-network solutions for each limitation. We intend to fund any identified preferred option non-network solutions through capex to opex substitution during the regulatory control period, rather than request step changes to our operational expenditure regulatory allowance.

Notwithstanding our approach to seeking efficient solutions to project augmentation, we have undertaken a high-level assessment of non-network options by considering the benefits of deferring expenditure by one year against a plausible alternative of procuring capacity from the market based on recent RIT-D responses. Applying this methodology to distributed storage solutions, we determined that the installed costs of $255.3 million is greater than the $51.6 million installed costs of the preferred network option. Furthermore, applying this methodology to the lowest-cost demand response solution, we determined that the costs of $5.3 million pa is also greater than the network augmentation deferral benefit of $2.7 million pa. Therefore, the non-network options are not the preferred approach based on program-wide network benefits alone.

2.5 Consumer Energy Resources

Decentralisation, digitisation, decarbonisation and electrification are fundamentally changing the structure and function of the electricity system. Our network will need to continue to evolve from a network which provides one-directional flow to the crucial platform which underpins energy use in our network area.

Given the expanded role of our network – in terms of scale, function and criticality – we are keen ensure we also take advantage of the available opportunities to make the most of our existing network before building more.

A key aspect of this is our Consumer Energy Resources (CER) Strategy which includes:

- **Modernising the grid** – enable and support the uptake of CER on the network, including flexible services using Dynamic Operating Envelopes (**DOE**) to remove static export and import limits, reduce CER curtailment, improve CER exports, and improve voltage, supply quality and system security compliance.
- **Seeding the market** – stimulate growth in the efficient use of CER to support the broader market, including data visibility for customers, enhanced tariffs such as for solar soak and EV charging, and use common communication protocols to support CER aggregation by market service providers.

Our demand forecast is premised on the roll-out of our CER strategy. For example, it takes into account the continued impact of solar in reducing peak demand (until the peak demand shifts later in the evening) and moderates the impact of EV charging overtime, based on expected roll-out of cost-reflective tariffs and consumers who opt-into forms of managed charging. Or put another way, the network constraints identified already incorporate the impact of our CER strategy.

This strategy also considers a sensitivity where our CER strategy is more effective than anticipated (all EV charging load is removed from our demand forecast). This sensitivity shows the impact of what could occur if all EV charging was subject to dynamic operating envelopes, considered as part of our CER strategy.

3. Assessment Methodology and Assumptions

This section outlines the method that we apply in assessing its network risks and limitations for each credible solution and of the feasible options. It presents key assumptions and input information applied to the assessments in this document.

3.1 Probabilistic Planning

In accordance with clause 5.17.1(b) of the National Electricity Rules, our augmentation investment decisions are aligned with the Regulatory Investment Test for Distribution (RIT-D). This test aims 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 method that considers the likelihood and severity of critical network conditions and outages and their duration. The method compares the forecast cost to consumers of a loss of energy supply due to a network limitation, against the proposed augmentation cost to mitigate the energy supply risk.

The annual cost to consumers is calculated by multiplying the expected unserved energy (**EUE**) (the expected energy not supplied based on the probability and duration of the supply capacity limitation occurring in a year - a proxy for supply reliability) by the Value of Customer Reliability (**VCR**).

The present value of this expected benefit is then compared with the costs of the feasible solutions and options. In essence, the total lifecycle cost for each credible solution and option includes the project capital cost, the annual on-going operating and maintenance expenditure (**O&M**), and the annual cost of the EUE.

3.2 Assessment Assumptions

In evaluating net economic benefits, the following assumptions are used to calculate the annualised value of expected unserved energy for all the options analysed in this paper:

- Value of Customer Reliability (VCR) of $47,905 per MWh (FY24$);
- Average feeder outage rate is calculated based on recent years of JEN's actual historic reliability data;
- Sub-transmission line outage frequency, which is 0.09 outages per kilometre of line length per year;
- Sub-transmission line outage average duration of 4 hours per outage;
- Power transformer outage frequency, which is 0.01 outages per year;
- Power transformer outage average duration of 2.65 months per outage;
- Regulatory discount rate of 5.18%;
- Economic analysis period for cost-benefit analysis set at 20 years;
- Distribution feeder EUE based on 6-year demand forecast, held constant thereafter;
- Zone substation and sub-transmission EUE based on 10-year demand forecast, held constant thereafter; and
- 70% weighting on 50% PoE, and 30% weighting on 10% PoE for calculation of the EUE.

4. Base Case

The base case Option 1 (do nothing) assumes no additional investment into the network to address the existing and forecast network limitations identified in section 2.3.

Table 4-1 details the zone substation EUE for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-1: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 1

Asset	ST	COO	COO Bus No.1 REFCL[23]	COO Bus No.2 REFCL[23]	Total
2025	0.0	0.5	0.0	0.0	**0.5**
2026	0.0	0.7	0.0	0.0	**0.7**
2027	0.0	1.5	0.0	0.0	**1.6**
2028	0.3	2.1	0.1	0.5	**3.0**
2029	0.7	2.7	0.2	1.4	**5.1**
2030	1.6	4.7	0.5	3.1	**9.9**
2031	5.2	7.6	0.8	6.2	**19.8**
2032	19.2	12.0	1.3	11.9	**44.4**
2033	67.7	17.7	2.1	20.6	**108**
2034	193	24.8	3.4	34.0	**255**

Table 4-2 details the distribution feeder EUE for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-2: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 1

Asset	COO23	KLO13	KLO21	KLO22	ST 11	ST 12	ST 22	ST 32	ST 33	ST 34	Total
2025	0.0	24.0	3.8	0.0	1.9	0.0	0.0	0.0	0.0	0.0	**29.6**
2026	2.1	31.7	10.3	0.1	13.7	53.8	1.2	0.0	0.0	0.2	**113**
2027	11.6	40.3	72.4	21.0	40.7	2,532	16.6	0.0	2.9	1.9	**2,740**
2028	44.9	49.4	325	261	63.3	9,101	116.8	0.0	7.9	3.3	**9,972**
2029	115	56.0	749	705	75.9	18,072	748	0.0	10.5	3.8	**20,535**
2030	295	77.6	1,793	1,979	91.4	27,505	1,540	0.4	15.0	4.8	**33,301**

Applying the VCR, gives the values of the expected EUE over the forecast period.

[23] Assumes HV underground cables (and hence customers) are deenergised on days of total fire ban, in order to maintain Ico within the rating of the COO REFCLs.

Table 4-3 details the zone substation value of EUE for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-3: Zone Substation and Sub-transmission Value of Expected Unserved Energy (FY24$k,) – Option 1

Asset	ST	COO	COO Bus No.1 REFCL[24]	COO Bus No.2 REFCL[23]	Total
2025	0	23	0	0	**23**
2026	0	35	0	0	**35**
2027	2	73	0	0	**75**
2028	14	100	4	25	**143**
2029	35	129	11	69	**244**
2030	77	224	26	148	**475**
2031	250	363	41	295	**949**
2032	922	574	61	568	**2,126**
2033	3,244	848	100	985	**5,176**
2034	9,236	1,186	164	1,630	**12,217**

Table 4-4 details the distribution feeder value of EUE for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-4: Distribution Feeder Value of Expected Unserved Energy (FY24$k) – Option 1

Asset	COO23	KLO13	KLO21	KLO22	ST 11	ST 12	ST 22	ST 32	ST 33	ST 34	Total
2025	0	1,149	181	0	90	0	0	0	0	0	**1,420**
2026	100	1,521	492	5	656	2,576	57	0	1	11	**5,419**
2027	555	1,930	3,470	1,008	1,951	121,312	793	0	139	93	**131,250**
2028	2,150	2,364	15,575	12,498	3,033	435,966	5,598	1	379	157	**477,721**
2029	5,528	2,682	35,875	33,772	3,636	865,725	35,830	2	502	183	**983,735**
2030	14,118	3,720	85,891	94,787	4,378	1,317,635	73,786	21	718	230	**1,595,284**

24 Assumes HV underground cables (and hence customers) are deenergised on days of total fire ban, in order to maintain Ico within the rating of the COO REFCLs.

5. Options Analysis

5.1 Options Description and Scope

This section provides a summary of the solutions which combine to form the projects for each network development option that are designed to address the identified needs.

Table 5-1 provides a broad description of the scope of each option and their ability to address the identified network need, assuming all solution components are implemented in full.

Table 5-1: Options to address the identified need and their solution descriptions

<table>
<tr><th>Option</th><th>High-Level Description</th><th>Ability to address identified network need</th></tr>
<tr><td>Option 1
Do Nothing</td><td>This is the base case, assuming no additional expenditure in the NDS supply area.</td><td>Nil</td></tr>
<tr><td>Option 2
Craigieburn Plan</td><td>a) Install a new 66/22 kV REFCL 20/33 MVA two-transformers zone substation CBN in the Craigieburn area with new feeders and other feeder works in the area. Works to reduce COO REFCL capacitance.
b) Including a 3rd transformer at CBN towards the end of the planning period to address the N-1 overload risk at CBN.</td><td>Fully addresses N and N-1 overload risk at ST.
Fully addresses N overload risk at COO.
No material change in overload risk on SMTS-ST-SSS loop.
No material change in overload risk on TTS-COO-VCO-BD-BMS loop.
Fully addresses all feeders overload risk.
Fully addresses REFCL limitations at COO.</td></tr>
<tr><td>Option 3
Greenvale Plan</td><td>a) Install a new 66/22 kV REFCLREFCL 20/33 MVA two-transformers zone substation GVE in the Greenvale / Yuroke area with new feeders and other feeder works in the area. Works to reduce COO REFCL capacitance.
b) Including a 3rd transformer at GVE towards the end of the planning period to address the N-1 overload risk at GVE.</td><td>Fully addresses N and N-1 overload risk at ST.
Fully addresses N overload risk at COO.
No material change in overload risk on SMTS-ST-SSS loop.
No material change in overload risk on TTS-COO-VCO-BD-BMS loop.
Fully addresses all feeders overload risk.
Fully addresses REFCL limitations at COO.</td></tr>
<tr><td>Option 4
BESS Plan</td><td>70 MW / 500 MWh BESS ramp up over 10 years, distributed across ST, KLO and COO 22 kV feeders.</td><td rowspan="2">Fully addresses N and N-1 overload risk at ST.
Fully addresses N overload risk at COO.
Reduced overload risk on SMTS-ST-SSS loop.
Reduced overload risk on TTS-COO-VCO-BD-BMS loop.
Fully addresses all feeders overload risk.</td></tr>
<tr><td>Option 5
DM Plan</td><td>70 MW / 500 MWh DM ramp up over 10 years, distributed across ST, KLO and COO 22 kV feeders.</td></tr>
</table>

		Does not fully address REFCL limitations at COO.

It is forecast that if Option 2 or Option 3 are implemented, the new zone substation (CBN or GVE) will be operating over its N-1 rating in order to adequately address the forecast HV feeder N rating overload risk. A sub-option is provided with each option to assess the economic viability of a third transformer at the new zone substation later in the planning period.

Table 5-2 itemises the solutions within each of the network development option assessed in this NDS.

Table 5-2: Summary of solutions comprising each network option

<table>
<tr><th>Asset</th><th>Option 1
Do Nothing</th><th>Option 2
Craigieburn (CBN)</th><th>Option 3
Greenvale (GVE)</th></tr>
<tr><td>COO Bus No.1 REFCL</td><td rowspan="15">Nil</td><td colspan="2">8.1.1 Coolaroo No.1 bus cable transfers</td></tr>
<tr><td>COO Bus No.2 REFCL</td><td colspan="2">8.1.2 Coolaroo No.2 bus feeders</td></tr>
<tr><td>COO</td><td colspan="2">8.1.2 Coolaroo No.2 bus feeders</td></tr>
<tr><td rowspan="2">ST</td><td colspan="2">Load transfer from ST 24 to BD 09 – close 17960, open ST 24 CB</td></tr>
<tr><td>8.2.1 Establish new Craigieburn (CBN) zone substation - zone substation works
8.2.2 Establish new Craigieburn (CBN) zone substation - HV feeder works
Load transfers from ST to CBN (post CBN)</td><td>8.3.1 New 66/22 kV zone substation at GVE
8.3.2 New 22 kV feeders at GVE
Load transfers from ST to GVE via COO (post GVE)</td></tr>
<tr><td>ST 34</td><td colspan="2">8.1.4 Augment feeder BD0-008</td></tr>
<tr><td>COO23</td><td colspan="2">8.1.2 Coolaroo No.2 bus feeders</td></tr>
<tr><td>KLO13</td><td colspan="2" rowspan="2">8.1.3 New feeder KLO-023</td></tr>
<tr><td>KLO21</td></tr>
<tr><td>KLO22</td><td rowspan="6">8.2.1 Establish new Craigieburn (CBN) zone substation - zone substation works
8.2.2 Establish new Craigieburn (CBN) zone substation - HV feeder works
Load transfers from ST & KLO feeders to CBN (post CBN)</td><td rowspan="6">8.3.1 New 66/22 kV zone substation at GVE
8.3.2 New 22 kV feeders at GVE
Load transfers from ST & KLO feeders to GVE via COO (post GVE)</td></tr>
<tr><td>ST 11</td></tr>
<tr><td>ST 12</td></tr>
<tr><td>ST 22</td></tr>
<tr><td>ST 32</td></tr>
<tr><td>ST 33</td></tr>
</table>

5.2 Options Project and On-going Operational Costs

Table 5-4 summarises the credible network solution capital costs and scope of work, and the identified optimum economic timing of each solution based on the EUE risk of the associated network limitation.

Table 5-3: Summary of Credible Network Solution Capital and Annualised Costs (FY24$)

Credible Network Solutions	Scope of Work Section	Option	Capital Cost ($M)	Annual Cost ($k pa)	Network Limitation	Optimum Timing25
Augment feeder BD0-008	8.1.4	2,3	[redacted]	[redacted]	ST N and N-1 ST34 overload	2026
Coolaroo No.1 bus cable transfers	8.1.1	2,3	[redacted]	[redacted]	COO Bus No.1 REFCL	2027
Coolaroo No.2 bus feeders	8.1.2	2,3	[redacted]	[redacted]	COO Bus No.2 REFCL COO N & COO23 overload	2027
New feeder KLO-023	8.1.3	2,3	[redacted]	[redacted]	KLO13 and 21 overload	2026
Establish new Craigieburn (CBN) zone substation - zone substation works	8.2.1	2	[redacted]	[redacted]	ST N and N-1 overload	2027
Establish new Craigieburn (CBN) zone substation - HV feeder works	8.2.2	2	[redacted]	[redacted]	KLO22 overload	2027
New 66/22 kV zone substation at GVE	8.3.1	3	[redacted]	[redacted]	ST 11, 12, 22, 32 and 34 overload	2027
New 22 kV feeders at GVE	8.3.2	3	[redacted]	[redacted]		2027
Third 66/22 kV transformer at CBN	-	2	[redacted]	[redacted]	CBN N-1 overload	2033
Third 66/22 kV transformer at GVE	-	3	[redacted]	[redacted]	GVE N-1 overload	2035

Based on an aggregation of the cost of the various solutions above that make up each option and their optimum timing based on a comparison of their annualised costs with the do-nothing value of EUE, the costs for each option are summarised in Table 5-4 below. Present values are calculated over an economic analysis period of 20 years.

[25] Year in which the value of EUE exceeds the annualised cost of the solution.

Table 5-4: Summary of Option Costs ($M)

Cost	Option 1	Option 2	Option 3
Option total capital cost	**0.0**	**49.2**	**61.7**
PV of total capital cost	0.0	44.9	56.3
PV of O&M cost	0.0	6.7	8.4
PV of option total capital and O&M cost	**0.0**	**51.6**	**64.7**

5.3 Options Ability to Address the Need

This section presents the maximum demand forecast and asset utilisations over the next 10 years for the supply area, taking into account the impact of each option and its ability to address the forecast overloads on the network as was tabulated in Table 2-6, Table 2-7, Table 2-8, Table 2-9, and Table 2-10.

This assessment supports us in determining the option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM, and which is therefore consistent with the long-term interests of our customers.

The “do nothing” option presents the forecast EUE for the NDS supply area, assuming none of the identified network development options are implemented. It is used as a base case against which all of the credible network development options are compared, and shows the comparative benefits of each credible option.

The risks associated with the “do nothing” option are:

- Inability to connect new customer load;
- Increased risk of breaching statutory clearances (green book) on bare overhead conductors;
- Increased risk of failure of equipment (e.g., cables, joints, etc.) when equipment operated above limits;
- Inability to restore all lost supplies in the event of loss of a critical asset during peak demand period;
- Increased risk of bushfire starts and non-compliance with the Victorian bushfire safety regulations due to deteriorating REFCL performance;
- Deterioration of supply reliability due to capacity shortfall; and
- Intangible costs to JEN arising from negative publicity due to longer supply restoration time during and following hot weather events.

Table 5-5 presents the new ratings from the year of the optimum timing of works for each option. Asset not listed in this table have no change to their ratings, and therefore the Option 1 ratings presented in section 2.1.1 apply to those assets.

Table 5-5: Summer and Winter Ratings Before and After Planned Works (MVA)[26]

Asset	Option	Before	After	Solution Applied
CBN N-1 Rating CBN N Rating	2	0.0 / 0.0 0.0 / 0.0	38.0 / 39.6 66.0 / 66.0	8.2.1
GVE N-1 Rating	3	0.0 / 0.0	38.0 / 39.6	8.3.1

[26] (N-1) cyclic ratings for sub-transmission and zone substations. (N) rating for 22 kV feeders.

Asset	Option	Before	After	Solution Applied
GVE N Rating		0.0 / 0.0	66.0 / 66.0	
COO N-1 Rating COO N Rating	2	38.0 / 39.6 46.5 / 47.6	38.0 / 39.6 57.9 / 58.3	8.2.1 & 8.1.2
COO N-1 Rating COO N Rating	3	38.0 / 39.6 46.5 / 47.6	38.0 / 39.6 57.5 / 57.5	8.3.1 & 8.1.2
CBN11	2	0.0	14.3	8.2.2
CBN12	2	0.0	14.3	8.2.2
CBN13	2	0.0	12.7	8.2.2
CBN21	2	0.0	12.7	8.2.2
CBN22	2	0.0	12.7	8.2.2
CBN23	2	0.0	14.3	8.2.2
GVE11	3	0.0	12.7	8.3.2
GVE12	3	0.0	13.7	8.3.2
GVE13	3	0.0	13.7	8.3.2
GVE21	3	0.0	13.7	8.3.2
GVE22	3	0.0	13.7	8.3.2
COO21	3	14.3	12.7	8.3.2
KLO23	2, 3	14.3	24.0	8.1.3

Table 5-6 presents the 10% PoE summer maximum demand zone substation forecast for the forward 10-year planning period following the proposed works for each option, assuming all of the solution components of each option are implemented now. Assets not listed have the same forecast as Option 1 detailed in Table 2-6. Values highlighted are an identified network limitation with red exceeding the (N-1) rating and **bold red** exceeding the (N) rating.

Table 5-6: 10% PoE Summer Maximum Demand Forecast and Ratings (MVA) After Proposed Works

Asset	Option	Rating	2027	2028	2029	2030	2031	2032	2033	2034
ST	**2**	**79.7**	62.2	63.9	65.3	66.4	67.9	69.6	71.3	72.7
COO	**2**	**38.0**	42.0	42.5	42.6	43.9	45.0	46.1	47.1	47.9
CBN	**2**	**38.0**	39.4	43.4	46.5	49.1	51.6	53.9	56.2	58.2
ST	**3**	**79.7**	68.8	70.3	71.2	71.7	72.8	74.3	75.7	77.0
COO	**3**	**38.0**	38.1	39.1	40.0	41.1	42.3	43.4	44.5	45.4
GVE	**3**	**38.0**	34.4	38.6	41.8	44.9	47.8	50.4	53.0	55.2

Table 5-7 presents the 10% PoE winter maximum demand zone substation forecast for the forward 10-year planning period following the proposed works for each option, assuming all of the solution components of each option are implemented now. Assets not listed have the same forecast as Option 1 detailed in Table 2-7. Values highlighted are an identified network limitation with red exceeding the (N-1) rating and **bold red** exceeding the (N) rating.

Table 5-7: 10% PoE Winter Maximum Demand Forecast and Ratings (MVA) After Proposed Works

Asset	Option	Rating	2027	2028	2029	2030	2031	2032	2033	2034
ST	**2**	**89.3**	64.4	66.0	67.3	68.0	68.9	70.0	71.0	72.1
COO	**2**	**39.6**	33.2	33.7	34.1	35.2	35.5	36.3	37.1	37.9
CBN	**2**	**39.6**	38.9	43.9	47.8	51.3	54.2	57.0	59.7	62.3
ST	**3**	**89.3**	71.6	72.9	73.7	73.7	74.2	75.0	75.8	76.7
COO	**3**	**39.6**	30.1	31.3	32.3	33.4	34.2	35.1	36.0	36.9
GVE	**3**	**39.6**	31.8	36.9	41.0	45.2	48.4	51.4	54.3	56.9

Table 5-8 presents the 10% PoE summer maximum demand distribution feeder forecast for the forward 10-year planning period following the proposed works for each option, assuming all of the solution components of each option are implemented at their optimal timing. Assets not listed have the same forecast as Option 1 detailed in Table 2-8. Shaded cells are loads before the transfers are implemented.

Table 5-8: Distribution Feeder 10% PoE Summer Maximum Demand Forecast (MVA) After Planned Works

Feeder	Option	New Rating	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
CBN11	**2**	**14.3**	10.4	11.3	12.2	12.9	13.4	13.8	14.3	**14.6**	0.2 MVA from ST 22 2.5 MVA from ST 11 1.9 MVA from ST 33 30% of ST 12
CBN12	**2**	**14.3**	6.9	7.7	8.2	8.6	8.9	9.3	9.7	10.1	33% of ST 22
CBN13	**2**	**12.7**	6.5	7.3	7.8	8.4	9.0	9.5	10.0	10.5	2.5 MVA from ST 22 25% of KLO22
CBN21	**2**	**12.7**	4.8	5.8	6.4	7.1	7.7	8.4	9.0	9.6	30% of KLO22
CBN22	**2**	**12.7**	8.7	9.5	10.1	10.7	11.2	11.6	12.0	12.4	1.5 MVA from ST 22 1.2 MVA from ST 33 1.5 MVA from ST 11 15% of ST12 10% of KLO22
CBN23	**2**	**14.3**	6.9	7.7	8.2	8.6	8.9	9.3	9.7	10.1	33% of ST 22
GVE11	**3**	**12.7**	8.9	9.5	9.8	10.1	10.5	10.8	11.2	11.5	50% of COO23
GVE12	**3**	**13.7**	6.4	7.7	8.5	9.4	10.3	11.2	12.0	12.7	40% of KLO22
GVE13	**3**	**13.7**	7.7	9.0	10.1	11.0	11.8	12.3	12.9	13.4	40% of ST 12
GVE21	**3**	**13.7**	9.2	10.0	10.7	11.4	12.0	12.5	12.9	13.4	25% of ST 12 10% of ST 32 35% of ST 33
GVE22	**3**	**13.7**	6.4	7.7	8.5	9.4	10.3	11.2	12.0	12.7	40% of KLO22
COO11	**2,3**	**10.9**	5.2	5.3	5.3	5.4	5.6	5.7	5.9	6.0	0.5 MVA to KLO22
COO13	**2,3**	**12.0**	4.6	4.6	4.6	4.7	4.7	4.8	4.9	4.9	100% of COO21
COO21	**2**	**14.3**	8.9	9.5	9.8	10.1	10.5	10.8	11.2	11.5	100% to COO13 50% of COO23
COO21	**3**	**12.7**	6.4	7.0	7.6	8.2	8.7	9.1	9.5	9.8	100% to COO13 30% of ST 32 20% of ST 12
COO22	**2,3**	**12.0**	4.6	4.6	4.7	4.8	4.9	5.0	5.1	5.2	50% to ST 21
COO23	**2**	**14.3**	8.9	9.5	9.8	10.1	10.5	10.8	11.2	11.5	50% to COO21
COO23	**3**	**14.3**	8.9	9.5	9.8	10.1	10.5	10.8	11.2	11.5	50% to GVE11
COO24	**2,3**	**12.2**	5.1	5.1	5.2	5.3	5.4	5.5	5.7	5.8	50% to ST 21
KLO13	**2,3**	**14.3**	9.8	10.1	10.3	10.7	11.2	11.7	12.2	12.6	40% to KLO23
KLO21	**2,3**	**14.3**	8.3	9.3	10.0	10.7	11.1	11.6	12.1	12.6	50% to KLO23 via 13
KLO22	**2**	**14.3**	6.1	7.2	7.9	8.7	9.5	10.3	11.0	11.7	0.5 MVA from COO11 25% to CBN13 30% to CBN21 10% of CBN22

Feeder	Option	New Rating	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
KLO22	**3**	**14.3**	6.8	7.9	8.7	9.3	10.0	10.7	11.4	11.9	0.5 MVA from COO11 1.0 MVA to ST 12 20% of ST 22 40% to GVE12 40% to GVE22
KLO23	**2,3**	**24.0**	15.9	17.2	18.0	19.0	19.9	20.7	21.6	22.4	40% of KLO13 50% of KLO21
ST 11	**2**	**22.5**	11.6	11.9	12.2	12.7	13.2	13.8	14.4	14.9	2.5 MVA to CBN11 1.5 MVA to CBN22
ST 11	**3**	**22.5**	14.9	15.2	15.3	15.7	16.0	16.4	16.8	17.2	30% to ST 12 4.0 MVA from ST 22
ST 12	**2**	**14.3**	8.7	10.1	11.4	12.4	13.2	13.9	**14.5**	**15.1**	30% to CBN11 15% to CBN22 10% to ST 33
ST 12	**3**	**14.3**	8.6	9.1	9.6	10.1	10.6	11.0	11.3	11.7	40% to GVE13 25% to GVE21 20% to COO21 30% of ST 11 1.0 MVA from KLO22
ST 21	**2,3**	**14.3**	11.0	11.1	11.1	11.4	11.6	11.9	12.1	12.3	50% of COO22 50% of COO24
ST 22	**2**	**22.5**	2.7	3.5	4.0	4.4	4.7	5.1	5.5	5.9	0.2 MVA to CBN11 2.5 MVA to CBN13 1.5 MVA to CBN22 33% to CBN12 33% to CBN23
ST 22	**3**	**22.5**	11.5	13.3	14.5	15.3	16.1	17.0	17.9	18.7	5% to ST 33 20% to KLO22 4.0 MVA to ST 11
ST 32	**2**	**12.4**	8.3	8.4	8.5	8.9	9.3	9.7	10.1	10.5	Nil
ST 32	**3**	**12.4**	5.0	5.0	5.1	5.3	5.6	5.8	6.1	6.3	10% to GVE21 30% to COO21
ST 33	**2**	**12.5**	8.8	9.2	9.6	10.0	10.4	10.8	11.2	11.5	1.9 MVA to CBN11 1.2 MVA to CBN22 10% of ST 12
ST 33	**3**	**12.5**	7.5	7.7	7.8	8.0	8.2	8.4	8.6	8.8	35% to GVE21 5% from ST 22

Table 5-7 presents the 10% PoE summer maximum demand distribution feeder forecast for the forward 10-year planning period following the proposed works for each option, assuming all of the solution components of each option are implemented at their optimal timing. Assets not listed have the same forecast as Option 1 detailed in Table 2-9. Shaded cells are loads before the transfers are implemented.

Table 5-9: Distribution Feeder 10% PoE Winter Maximum Demand Forecast (MVA) After Planned Works

Feeder	Option	New Rating	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
CBN11	**2**	**14.3**	10.5	11.6	12.6	13.5	14.1	14.6	15.1	**15.6**	0.2 MVA from ST 22 2.5 MVA from ST 11 1.9 MVA from ST 33 30% of ST 12
CBN12	**2**	**14.3**	7.5	8.4	9.1	9.6	10.0	10.5	10.9	11.4	33% of ST 22
CBN13	**2**	**12.7**	6.6	7.5	8.1	8.9	9.5	10.1	10.7	11.2	2.5 MVA from ST 22 25% of KLO22
CBN21	**2**	**12.7**	4.9	6.0	6.8	7.6	8.4	9.1	9.8	10.5	30% of KLO22
CBN22	**2**	**12.7**	8.8	9.7	10.5	11.2	11.8	12.3	12.7	**13.2**	1.5 MVA from ST 22 1.2 MVA from ST 33 1.5 MVA from ST 11 15% of ST12 10% of KLO22
CBN23	**2**	**14.3**	7.5	8.4	9.1	9.6	10.0	10.5	10.9	11.4	33% of ST 22
GVE11	**3**	**12.7**	7.4	8.1	8.5	9.0	9.4	9.7	10.0	10.4	50% of COO23
GVE12	**3**	**14.5**	6.6	8.0	9.0	10.2	11.2	12.1	13.1	13.9	40% of KLO22
GVE13	**3**	**13.7**	7.9	9.3	10.7	11.9	12.7	13.4	14.0	**14.6**	40% of ST 12
GVE21	**3**	**13.7**	9.0	10.0	11.0	11.9	12.5	13.1	13.6	**14.1**	25% of ST 12 10% of ST 32 35% of ST 33
GVE22	**3**	**14.5**	6.6	8.0	9.0	10.2	11.2	12.1	13.1	13.9	40% of KLO22
COO11	**2,3**	**10.9**	5.0	5.2	5.3	5.4	5.6	5.8	5.9	6.1	0.5 MVA to KLO22
COO13	**2,3**	**12.0**	7.4	7.4	7.4	7.4	7.5	7.5	7.5	7.5	100% of COO21
COO21	**2**	**14.3**	7.4	8.1	8.5	9.0	9.4	9.7	10.0	10.4	100% to COO13 50% of COO23
COO21	**3**	**12.7**	6.3	7.1	7.9	8.7	9.2	9.7	10.1	10.5	100% to COO13 30% of ST 32 20% of ST 12
COO22	**2,3**	**12.0**	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	50% to ST 21
COO23	**2**	**14.3**	7.4	8.1	8.5	9.0	9.4	9.7	10.0	10.4	50% to COO21
COO23	**3**	**14.3**	7.4	8.1	8.5	9.0	9.4	9.7	10.0	10.4	50% to GVE11
COO24	**2,3**	**12.2**	4.5	4.6	4.7	4.9	5.0	5.1	5.2	5.4	50% to ST 21
KLO13	**2,3**	**14.5**	8.0	8.5	8.8	9.3	9.8	10.2	10.7	11.1	40% to KLO23
KLO21	**2,3**	**14.5**	9.5	10.9	11.8	12.9	13.5	14.2	14.8	**15.4**	50% to KLO23 via 13

Feeder	Option	New Rating	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
KLO22	**2**	**14.3**	6.2	7.5	8.4	9.4	10.3	11.1	12.0	12.7	0.5 MVA from COO11 25% to CBN13 30% to CBN21 10% of CBN22
KLO22	**3**	**14.3**	8.6	9.5	10.3	11.1	11.9	12.6	13.3	5.9	0.5 MVA from COO11 1.0 MVA to ST 12 20% of ST 22 40% to GVE12 40% to GVE22
KLO23	**2,3**	**24.0**	16.2	18.0	19.2	20.7	21.7	22.7	23.7	24.7	40% of KLO13 50% of KLO21
ST 11	**2**	**22.6**	16.2	17.0	17.5	18.3	19.1	20.0	20.8	21.7	2.5 MVA to CBN11 1.5 MVA to CBN22
ST 11	**3**	**22.6**	18.2	18.7	19.1	19.6	20.2	20.8	21.4	22.0	30% to ST 12 4.0 MVA from ST 22
ST 12	**2**	**14.6**	8.9	10.5	12.0	13.4	14.3	**15.1**	**15.8**	**16.5**	30% to CBN11 15% to CBN22 10% to ST 33
ST 12	**3**	**14.3**	10.0	10.8	11.5	12.2	12.7	13.2	13.7	14.2	40% to GVE13 25% to GVE21 20% to COO21 30% of ST 11 1.0 MVA from KLO22
ST 21	**2,3**	**14.3**	10.2	10.4	10.6	10.8	11.0	11.3	11.5	11.8	50% of COO22 50% of COO24
ST 22	**2**	**22.5**	3.3	4.2	4.9	5.4	5.8	6.3	6.7	7.2	0.2 MVA to CBN11 2.5 MVA to CBN13 1.5 MVA to CBN22 33% to CBN12 33% to CBN23
ST 22	**3**	**22.5**	12.8	14.9	16.6	17.5	18.5	19.5	20.6	21.7	5% to ST 33 20% to KLO22 4.0 MVA to ST 11
ST 32	**2**	**12.6**	7.9	8.2	8.5	9.0	9.5	9.9	10.3	10.8	0.7 MVA xfer in 2034
ST 32	**3**	**12.6**	4.8	4.9	5.1	5.4	5.7	5.9	6.2	6.5	10% to GVE21 30% to COO21
ST 33	**2**	**12.5**	8.3	8.9	9.4	10.0	10.5	10.9	11.3	11.7	1.9 MVA to CBN11 1.2 MVA to CBN22 10% of ST 12
ST 33	**3**	**12.5**	7.3	7.5	7.8	8.0	8.2	8.5	8.7	9.0	35% to GVE21 5% from ST 22

Table 5-10, Table 5-11, Table 5-12, and Table 5-13 presents the forecast levels of Ico expected at COO, CBN and GVE zone substations over the next 10-years based after proposed works for each option, assuming all of the solution components of each option are implemented at their optimal timing. Assets not listed have the same forecast as Option 1 detailed in Table 2-10. Shaded cells are loads before the transfers are implemented.

Table 5-10: Forecast Ico at COO (Amps) After Planned Works – Option 2

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
COO11	-	68	70	40	41	42	43	44	45	46	47
COO12	-	43	45	38	39	40	42	43	44	46	47
COO13	-	0	0	2	2	2	2	2	2	2	2
COO14	-	0	0	0	0	0	0	0	0	0	0
BUS No.1	**120**	**111**	**115**	**80**	**82**	**84**	**87**	**89**	**92**	**94**	**96**
COO21	-	2	2	76	82	87	93	98	104	110	117
COO22	-	106	109	49	51	52	53	55	56	58	59
COO23	-	104	112	60	65	70	75	80	85	91	96
COO24	-	64	64	28	28	28	28	28	28	28	28
BUS No.2	**300**	**276**	**287**	**214**	**225**	**237**	**249**	**261**	**274**	**287**	**300**

Table 5-11: Forecast Ico at CBN (Amps) After Planned Works – Option 2

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CBN11	-	0	0	53	57	61	64	66	68	71	73
CBN12	-	0	0	34	37	40	42	44	46	48	49
CBN13	-	0	0	48	50	53	57	60	64	68	71
BUS No.1	**300**	**0**	**0**	**135**	**145**	**154**	**163**	**171**	**178**	**186**	**194**
CBN21	-	0	0	0	45	50	55	59	64	69	74
CBN22	-	0	0	0	53	56	59	61	64	67	69
CBN23	-	0	0	0	37	40	42	44	46	48	49
BUS No.2	**300**	**0**	**0**	**0**	**136**	**147**	**156**	**164**	**173**	**183**	**193**

Table 5-12: Forecast Ico at COO (Amps) After Planned Works – Option 3

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
COO11	-	68	70	40	41	42	43	44	45	46	47

COO12	-	43	45	38	39	40	42	43	44	46	47
COO13	-	0	0	2	2	2	2	2	2	2	2
COO14	-	0	0	0	0	0	0	0	0	0	0
BUS No.1	**120**	**111**	**115**	**80**	**82**	**84**	**87**	**89**	**92**	**94**	**96**
COO21	-	2	2	61	62	64	66	67	69	71	73
COO22	-	106	109	49	51	52	53	55	56	58	59
COO23	-	104	112	60	65	70	75	80	85	91	96
COO24	-	64	64	28	28	28	28	28	28	28	28
BUS No.2	**300**	**276**	**287**	**198**	**206**	**214**	**222**	**230**	**238**	**247**	**256**

Table 5-13: Forecast Ico at GVE (Amps) After Planned Works – Option 3

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
GVE11	-	0	0	55	59	62	68	71	74	78	81
GVE12	-	0	0	56	60	66	73	79	85	92	98
GVE13	-	0	0	51	53	58	63	67	71	75	79
BUS No.1	**300**	**0**	**0**	**162**	**172**	**187**	**204**	**217**	**231**	**245**	**258**
GVE21	-	0	0	0	50	53	57	59	62	65	68
GVE22	-	0	0	0	60	66	73	79	85	92	98
BUS No.2	**300**	**0**	**0**	**0**	**110**	**120**	**130**	**138**	**147**	**157**	**166**

5.4 Options Reliability Assessment

The following tables detail the annualised EUE for each option, assuming all solutions are in service based on their optimal timing as identified in Table 5-3.

5.4.1 Option 2 – Craigieburn Plan

Table 5-14 details the zone substation residual EUE for Option 2 over the planning horizon for the identified network limitations.

Table 5-14: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 2

Asset	CBN	ST	COO	COO Bus No.1 REFCL[23]	COO Bus No.2 REFCL[23]	Total
2025	0.0	0.0	0.5	0.0	0.0	**0.5**
2026	0.0	0.0	0.7	0.0	0.0	**0.7**
2027	0.0	0.0	0.1	0.0	0.0	**0.1**
2028	0.0	0.0	0.2	0.0	0.0	**0.2**
2029	0.4	0.0	0.4	0.0	0.0	**0.8**
2030	1.5	0.0	0.7	0.0	0.0	**2.2**
2031	3.4	0.0	1.2	0.0	0.0	**4.7**
2032	6.8	0.0	2.0	0.0	0.0	**8.8**
2033	0.0	0.0	3.1	0.0	0.0	**3.1**
2034	0.0	0.0	4.5	0.0	0.0	**4.5**

Table 5-15 details the distribution feeder residual EUE for Option 2 over the planning horizon for the identified network limitations.

Table 5-15: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 2

Asset	COO23	KLO13	KLO21	KLO22	ST 11	ST 12	ST 22	ST 32	ST 33	ST 34	Total
2025	0.0	24.0	3.8	0.0	1.9	0.0	0.0	0.0	0.0	0.0	**29.6**
2026	2.1	0.0	0.0	0.0	13.7	53.8	1.2	0.0	0.0	0.0	**70.8**
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

5.4.2 Option 3 – Greenvale Plan

Table 5-16 details the zone substation residual EUE for Option 3 over the planning horizon for the identified network limitations.

Table 5-16: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 3

Asset	GVE	ST	COO	COO Bus No.1 REFCL[23]	COO Bus No.2 REFCL[23]	Total
2025	0.0	0.0	0.5	0.0	0.0	**0.5**
2026	0.0	0.0	0.7	0.0	0.0	**0.7**
2027	0.0	0.0	0.0	0.0	0.0	**0.1**
2028	0.0	0.0	0.1	0.0	0.0	**0.1**
2029	0.0	0.0	0.2	0.0	0.0	**0.2**
2030	0.0	0.0	0.4	0.0	0.0	**0.5**
2031	0.3	0.0	0.8	0.0	0.0	**1.1**
2032	1.3	0.0	1.4	0.0	0.0	**2.8**
2033	3.8	0.0	2.4	0.0	0.0	**6.2**
2034	8.1	0.0	3.7	0.0	0.0	**11.9**

Table 5-17 details the distribution feeder residual EUE for Option 3 over the planning horizon for the identified network limitations.

Table 5-17: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 3

Asset	COO23	KLO13	KLO21	KLO22	ST 11	ST 12	ST 22	ST 32	ST 33	ST 34	Total
2025	0.0	24.0	3.8	0.0	1.9	0.0	0.0	0.0	0.0	0.0	**29.6**
2026	2.1	0.0	0.0	0.0	13.7	53.8	1.2	0.0	0.0	0.0	**70.8**
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

6. Economic Evaluation

This section presents the results of an economic cost-benefit analysis undertaken on each option. It takes into account the present value of capital and additional operating costs, and the present value of the EUE over an analysis period of 20-years. Capital costs over the 10-year planning horizon are included which address all of the identified network needs over the same period.

6.1 Cost-Benefit Analysis

A summary of the cost-benefit analysis assessed for each option is present in Table 6-1. Option 2 maximises the NPV, relative to all other options assessed.

Table 6-1: Summary of NPV Cost-Benefit Analysis (FY24$M)

Option	Total Capital Cost	Present Value of Capital and O&M Cost	Present Value of Reliability Benefit	Net Present Value (NPV)	Ranking
Option 1 - Do Nothing	0	0.0	0.0	0.0	5
Option 2 – Craigieburn Plan	**49.2**	**51.6**	**489.1**	**437.5**	**1**
Option 3 - Greenvale Plan	61.7	64.7	490.9	426.3	2
Option 4 – BESS Plan	0	255.3	489.1	233.8	4
Option 5 – DM Plan	0	106.0	489.1	383.1	3

6.2 Sensitivity Analysis

A sensitivity analysis has been undertaken to test the robustness of the preferred network development option to credible optimistic and pessimistic changes in key input assumptions. These changes are applied individually to each option as follows:

- Reducing VCR by 10%, thereby reducing customer benefits by 10%;
- Increasing VCR by 10%, thereby increasing customer benefits by 10%;
- Raising the discount rate by 1%, thereby reducing the attractiveness of capex investments;
- Lowering the discount rate by 1%, thereby improving the attractiveness of capex investments;
- Incurring 30% higher capital costs across all projects with an associated rise in the O&M;
- Achieving 30% lower capital costs across all projects with an associated reduction in the O&M; and
- No EV charging during peak electricity demand periods.

Table 6-2 presents the results for the sensitivity analysis.

Table 6-2: Sensitivity of NPV to Changes in Input Assumptions (FY24$M)

Option	Baseline	VCR 10% Lower	VCR 10% Higher	Discount Rate 1% Higher	Discount Rate 1% Lower	Capital Costs 30% Higher	Capital Costs 30% Lower	No EV Charging at Peak Demand
Option 1 - Do Nothing	0	0	0	0	0	0	0	0
Option 2 – Craigieburn Plan	**437**	**389**	**486**	**416**	**460**	**422**	**453**	**404**
Option 3 - Greenvale Plan	426	377	475	405	449	407	446	393

Option 2 remains the preferred network development option, retaining the highest positive NPV for all credible sensitivities.

Table 6-3 lists the project deferrals that would be triggered if all EV charging avoided peak electricity demand periods. No deferrals were identified.

Table 6-3: Deferrals for Option 2 with no EV Charging at Peak Electricity Demand

Projects	Revised Timing	Years Deferred
Augment feeder BD0-008	2026	0
New feeder KLO-023	2026	0
Coolaroo No.1 bus cable transfers	2027	0
Coolaroo No.2 bus feeders	2027	0
Establish new Craigieburn (CBN) zone substation - zone substation works 66 kV sub-transmission line extension Establish new Craigieburn (CBN) zone substation - HV feeder works	2027	0
Third 66/22 kV transformer at CBN	2033	0

7. Recommendation and Next Steps

The assessment demonstrates that the preferred network development plan is to implement Option 2 (Craigieburn Plan) because this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred Option 2 provides a 20-year present value net market benefit of $437 million for the base scenario, with a present value of $44.9 million of investment (over 10-years, 2025 to 2034). The market benefits forecast to be delivered by the preferred solution are driven by a reduction in the amount of expected unserved energy over the planning period.

7.1 Recommended Development Plan

The preferred network development plan (Option 2) to address the identified network limitations includes the following projects with an estimated total capital cost of $49.2 million (FY24$), of which $8.6 million is outside of the FY2027-31 regulatory control period.

Table 7-1: Option 2 - Craigieburn Plan

Timing	Projects	Cost (FY24$)	Limitation Addressed
2026	Augment feeder BD0-008	[redacted]	ST (N & N-1) overload
2026	New feeder KLO-023	[redacted]	KLO13, KLO21 overload
2027	Coolaroo No.1 bus cable transfers	[redacted]	COO Bus No.1 REFCL
2027	Coolaroo No.2 bus feeders	[redacted]	COO Bus No.2 REFCL COO (N) overload COO23 overload
2027	Establish new Craigieburn (CBN) zone substation - zone substation works 66 kV sub-transmission line extension[27] Establish new Craigieburn (CBN) zone substation - HV feeder works	[redacted]	ST (N & N-1) overload ST feeders overload KLO22 overload
2033	Third 66/22 kV transformer at CBN	[redacted]	CBN (N-1) overload
Total		**$49.2 million**	
Present Value Total		**$44.9 million**	

[27] The 66kV sub-transmission line extension work is planned to be completed in 2025 as part of customer initiated project and the associated cost is excluded from the development plan. Refer to Major Customers NDS for further details.

[28] A RIT-D is currently underway for this project.

Table 7-2 lists the projects and their associated costs over the FY2027-31 regulatory control period.

Table 7-2: Option 2 - Craigieburn Plan, projects within FY2027-31 regulatory control period

Timing	Projects	Cost (FY24$)	Limitation Addressed
2026	Augment feeder BD0-008	[redacted]	ST (N & N-1) overload
2026	New feeder KLO-023		KLO13, KLO21 overload
2027	Coolaroo No.1 bus cable transfers		COO Bus No.1 REFCL
2027	Coolaroo No.2 bus feeders		COO Bus No.2 REFCL COO (N) overload COO23 overload
2027	Establish new Craigieburn (CBN) zone substation - zone substation works 66 kV sub-transmission line extension[30] Establish new Craigieburn (CBN) zone substation - HV feeder works		ST (N & N-1) overload ST feeders overload KLO22 overload
Total		**$40.7 million**	

[29] $8.6M of the recommended plan project costs are outside the FY2027-31 regulatory control period.

[30] The 66kV sub-transmission line extension work is planned to be completed in 2025 as part of customer initiated project and the associated cost is excluded from the development plan. Refer to Major Customers NDS for further details.

[31] A RIT-D is currently underway for this project.

8. Appendix A – High Level Scopes of Work

8.1 22 kV Feeders

8.1.1 Coolaroo No.1 bus cable transfers

This solution addresses the capacitive current limitations of the high-performance REFCL on COO Bus No.1 by transferring some underground cable sections of COO11 and COO12 to adjacent feeders from other zone substations.

The scope for cable transfers off COO11 to adjacent feeders involves:

Underground Section and Length	To Feeder	Additional cable required
Panorama Mt Ridley spur 16192 (fused) – 2.5 km	KLO22	0.2 km
Summit-Captain Pearson spur 19757 (fused) – 1.8 km	KLO22	0.3 km
Forest Red Gum – Mt Ridley spur 12353 (fused) – 2.6 km	KLO22	0.5 km
Jolly-Vanessa spur 19650 (fused) – 1.6 km	KLO22	0.6 km
Afred-Docker cable (Mickleham Rd end) – 0.8 km	KLO13	New normally open switch on CHP

The cable transfers will require fused switches to be installed at the kiosks where the cable is being transferred to in order to avoid replacement of the cable.

This work removes 9.3 km of HV underground cable from COO11.

The scope for cable transfers off COO12 involves:

- At 0.1 km out from the COO12 feeder CB exit cable, install and connect into the exit cable, 2.5km of 19/3.25AAC single circuit overhead line along the north side of Somerton Rd to connect into the existing COO12 22 kV overhead line near MMBW-Somerton.
- Repurpose the existing 2.6km of COO12 feeder exit cable along Somerton Rd as the rearranged COO21 feeder exit cable, as described in section 8.1.2.

This work removes 2.5 km of HV underground cable from COO12.

8.1.2 Coolaroo No.2 bus feeders

This solution addresses the capacitive current limitations of the base-performance REFCL on COO Bus No.2 by transferring some underground sections of COO22 and COO24 to ST 21. It also addresses the overload limitation on COO23 by splitting it in two parts by redirecting COO21 into the area, and transferring the existing COO21 (short cable) load onto COO13. This action also acts to transfer load from Bus No.2 to Bus No.1, better balancing the bus loads to increase the N rating of the COO zone substation. COO's summer and winter import capacities are limited by the rating of each of the:

- 66/22 kV transformers and their load sharing when the 22 kV bus-tie circuit breaker is in an open state. It is noted that the No.2 transformer which carries 71% of the total station load, limits the N 'thermal' rating of this station to 46.5 MVA (i.e., 33 MVA nameplate rating ÷ 71% load share = 46.5 MVA); and
- 66/22 kV transformers' 22 kV circuit breakers (i.e., to maintain 'secure' operation, the total station load should not exceed the rating of each of the transformer circuit breakers). It is noted that the transformer circuit breakers limit the N 'secure' rating of this station to 47.5 MVA.

On days of summer peak demand which usually corresponds to days of Total Fire Ban, the zone substation usually operates with a normally open 22 kV bus-tie circuit breaker to allow independent operation of the base-performance REFCL on Bus No.2, from the high-performance REFCL on Bus No.1. The 22 kV bus-tie circuit breaker is also opened if the station load exceeds its N 'secure' rating. Therefore, in both dot points above, access to the station's N transformer ratings are limited by the load share between each transformer when the 22 kV bus tie is open. Transferring the short feeder COO-21 to COO-13 to better balance the loading across Bus No.1 and Bus No.2, will reduce the share of the loading on Bus No.2 from 71% to 57%, and increase the N rating of the COO zone substation to 57.5 MVA (i.e., 33 MVA nameplate rating ÷ 57% revised load share = 57.5 MVA). This option will reduce the risk of overloading COO under N conditions.

[redacted]

The scope involves

- Reconnect the COO21 underground cable supplying VR Roxburgh Park to the No.2 S/S on COO13.
- Install 4.5km (only 2.0 km is required if section 8.1.1 for COO12 is implemented) of new 300 Al XLPE cable from No.1 S/S on COO21 to the spare switch in Mattina-Brendan kiosk substation on COO23. Position open point between COO23 and COO21 to splt COO23 into two equal load parts. The ratings of COO23 and COO21 remain the same.
- Adjust open points for ST 21 to pick up sufficient cable capacitance off COO22 and COO24 to bring the COO No.2 Bus Ico within its ratings.

[redacted]

8.1.3 New feeder KLO-023

Augmenting the lightly loaded feeder KLO23 can be implemented to offload heavily loaded feeders KLO13 and KLO21. The scope involves

- Create a KLO23 jumbo feeder by installing 3.0 km of 22 kV 300 Al xlpe underground cable to piggyback on KLO23 CB and piggyback to switch 13003 in Blessington-Manningham substation, via Donnybrook Rd. The rating of KLO23 is estimated to increase to 630 A (24.0 MVA).
- This is intended to be a temporary arrangement with the piggyback KLO23 feeder transferred (in future) to a new KLO Bus No.3 at the time AusNet installs a third transformer at KLO, so as to split this jumbo feeder into two standard feeders.
- Adjust open points as follows.

[redacted]

[redacted]

[redacted]

8.1.4 Augment feeder BD0-008

This solution addressed the N-overload at risk on the ST34 feeder and ST N and N-1 load at risk under Do Nothing option.

To support the growth in the BD area and to mitigate the network constraint on BD8 feeder, the BD08 feeder exit cable is required to be augmented within the next 10 year

[redacted]

The scope for BD08 feeder exit augmentation involves replacing existing feeder exit cable from BD zone substation to the first cable head pole (pole A001068) on Barry Rd with 146 metres of 22 kV 300 Al xlpe underground cable.

8.2 Craigieburn Zone Substation

8.2.1 Establish new Craigieburn (CBN) zone substation - zone substation works

Install a new two-transformer REFCLREFCL 66/22 kV 20/33 MVA zone substation (designated CBN) at C[redacted]

For the sub-transmission cut-in of CBN, extend the existing ST-SSS 66 kV line from ST by 5.0 km to CBN and loop back 5.0 km to ST by i) constructing a new 5.0 km 66 kV single circuit overhead line on the east side of the Hume Highway from the SSS exit at ST in Patullos Lane to the new CBN site, and ii) constructing a new 5.0km 66 kV double circuit overhead line on the west side of the Hume Highway from the ST-SSS line at Patullos Lane to the new CBN site.

[redacted]

The sub-transmission line extension is planned to be build as part of customer initiated connection project by end of 2025, prior to the optimal timing for CBN zone substation. The remaining work required to commission CBN when it is economically justified is the sub-transmission cut-in from the line extension.

[redacted]

In August 2014, JEN purchased a vacant lot at 750 Hume Highway near Amaroo Road, south east of Mt Ridley Rd in Craigieburn for the future zone substation. The total expenditure for that project was $1.55 million (Real, 2014). Establishment of services and access works were undertaken by JEN at the site in 2016, with a total expenditure of $1.57 million (Real, 2016).

[redacted]

8.2.2 Establish new Craigieburn (CBN) zone substation - HV feeder works

This option is required if a new zone substation is installed in Craigieburn, in order to utilise the capacity of the new zone substation and alleviate loading levels on ST zone substation, and on KLO and ST feeders (i.e., KLO22, ST 11, ST 12, ST 22 and ST 33).

It involves establishing six staged new feeders CBN11, CBN12, CBN13, CBN21, CBN22 and CBN23. Each feeder exit shall utilise underground cable that is rated to at least 375 A summer cyclic rating

- For CBN11, install 0.7 km of exit cable from the CBN11 CB to a CHP on the ST 22 backbone closest to the CBN zone substation. The rating of CBN11 is estimated to be 375 A (14.3 MVA).
- For CBN12 to supply the Amaroo Business Park developments, install 1.1 km of exit cable from the CBN12 CB to a kiosk in the southern end of Amaroo Business Park, and maintain a normally open tie with ST 22. The rating of CBN12 is estimated to be 375 A (14.3 MVA).
- For CBN13, install 1.1 km of exit cable from the CBN13 CB to the Royal-Westerfolds CHP, and installing a remote-controlled normally-open switch at this CHP to provide a tie with ST 22. Install 1.1 km of 240 Al xlpe 22 kV underground cable from Featherpark-Huntington to Serenity-Domain substation. The rating of CBN13 is estimated to be 335 A (12.7 MVA).
- For CBN21, install 0.6 km of exit cable from the CBN21 CB to the CHP on KLO22 at ACR16150 near CBN zone substation. The rating of CBN21 is estimated to be 335 A (12.7 MVA).
- For CBN22, install 1.4km of exit cable from the CBN22 CB to the Bingin-Emerald CHP, and installing a remote-controlled normally-open switch at this CHP to provide a tie with ST 22. The rating of CBN22 is estimated to be 335 A (12.7 MVA).
- For CBN23 to supply the Amaroo Business Park developments, install 1.1 km of exit cable from the CBN23 CB to a kiosk in the northern end of Amaroo Business Park, and maintain a normally open tie with CBN12. The rating of CBN23 is estimated to be 375 A (14.3 MVA).
- Adjust open points as shown below.

[redacted]

COO11

[redacted]

[redacted]

8.3 Greenvale Zone Substation

8.3.1 New 66/22 kV zone substation at GVE

Install a new two-transformer REFCL 66/22 kV 20/33 MVA zone substation (designated GVE) in the Greenvale or Yuroke area.

Tee into the SMTS-SSS 66 kV line at the corner of Somerton Rd and Sydney Rd by establishing 11.5 km of new 66 kV line (37/3.75 AAC 100/75ºC) along the north side of Somerton Rd and up Mickleham Rd to GVE.

Tee into the SSS-ST 66 kV line at ST in Sydney Rd by establishing 8.5 km of new 66 kV line (37/3.75 AAC 100/75ºC) along Craigieburn Rd to Mickleham Rd to GVE.

[redacted]

[redacted]

Note: A connection of GVE to the TTS-BMS-BD-VCO-COO loop is not viable as it would overload this loop under N-1 conditions. Connection of GVE to the SMTS-SSS-ST loop makes negligible change to the sub-transmission overload risk profile of the area.

8.3.2 New 22 kV feeders at GVE

This option is required if a new zone substation is installed in Greenvale, in order to utilise the capacity of the new zone substation and alleviate loading levels on ST zone substation, and on KLO and ST feeders (i.e., KLO22, ST 11, ST 12, ST 22 and ST 33).

It involves establishing five new feeders GVE11, GVE12, GVE13, GVE21 and GVE22. Each feeder exit shall utilise underground cable that is rated to at least 375 A summer cyclic rating.

- For GVE11, install 1.0km of exit cable from the GVE11 CB into switch 16898 in Pristine-Allure substation. The rating of GVE11 is estimated to be 335 A (12.7 MVA).
- For GVE12, install 3.5km of exit cable from the GVE12 CB to the northern CHP on Mickelham Rd for the Highlands West – Masterplan. The rating of GVE21 is estimated to be 360 A (13.7 MVA).
- For GVE13, install 1.2km of exit cable from the GVE13 CB to the northern CHP on Mickelham Rd for the Craigieburn West – Masterplan. The rating of GVE13 is estimated to be 360 A (13.7 MVA).
- For GVE21, install 1.0km of exit cable from the GVE21 CB to the southern CHP on Mickelham Rd for the Craigieburn West – Masterplan. The rating of GVE21 is estimated to be 360 A (13.7 MVA).
- For GVE22, install 3.3km of exit cable from the GVE22 CB to the southern CHP on Mickelham Rd for the Highlands West – Masterplan. The rating of GVE22 is estimated to be 360 A (13.7 MVA).
- Install 2.2 km of 240 Al xlpe 22 kV underground cable from switch 10074 in Newlyn-Pembroke to a new CHP north of switch 10927.
- Cut into the new COO21 feeder exit cable (from section 8.1.2) and connect into switch 12539 in Bage-Stillwell substation. The rating of COO21 is estimated to be 335 A (12.7 MVA).
- Install new normally-open remote-controlled switch at Sparkford-Penarth substation.
- To provide another feeder supply to the Amaroo Business Park developments, install 1.1 km of 300 Al cable from the CHP on KLO22 at ACR16150 to a kiosk in the Amaroo Business Park, and maintain a normally open tie with ST 22.
- Adjust open points as shown below.

[redacted]

[redacted]

[redacted]

[redacted]