Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review Proposal

North Western Growth Corridor Network Development Strategy

ELE-999-PA-EL-004

Authorisation

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History

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1.0	28/11/2023	Initial release	Rodney Bray
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Owning Functional Area

Business Function Owner:	Asset & Operations | Electricity Distribution

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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.
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
ACR	Automatic Circuit Recloser
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
CB	Circuit Breaker
CHP	Cable Head Pole
CIC	Customer Initiated Capital
CER	Consumer Energy Resources
DM	Demand Management
(E)	Existing
EUE	Expected Unserved Energy
EV	Electric Vehicle
(F)	Future
HV	High Voltage
Ico	Cable Capacitance Current in Ampere
JEN	Jemena Electricity Network
KTS	Keilor Terminal Station (owned by AusNet Services)
kV	kilovolts
MD	Maximum Demand
MGS	Manual Gas-insulated Switch
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
PLN	Plumpton Zone Substation (future REFCL zone substation)
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
SA	St Albans Zone Substation (owned by Powercor)
SAPS	Standalone Power Systems
SBY	Sunbury Zone Substation (non-REFCL zone substation)
SHM	Sydenham Zone Substation (REFCL zone substation)
SLD	Single Line Diagram
STPIS	Service Target Performance Incentive Scheme
TCPR	Transmission Connection Planning Report
UG	Underground Cable
V2G	Vehicle to Grid
VCR	Value of Customer Reliability
VEDCOP	Victorian Electricity Distribution Code of Practice
WACC	Weighted Average Cost of Capital

Executive Summary

Jemena 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 the lowest 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 plan for the area of the Jemena Electricity Network (**JEN**) west of Deep Creek and Jacksons Creek, bordered to the west, north and south by the Powercor service area boundary, servicing the localities of Sunbury, Gisborne South, Clarkefield, Wildwood, Diggers Rest, Plumpton, Fraser Rise, Bonnie Brook, Hillside, Bulla, Sydenham, Calder Park and Taylors Lakes. This supply area is serviced by our Sydenham (**SHM**), and Sunbury (**SBY**) zone substations by way of a network of 22 kV distribution feeders. This supply area currently comprises of over 36,000 electricity distribution customers.

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

The population of the supply area is 91,281 and this is forecast to grow to 182,249 by 2046, an increase of 100% (or 4.2% pa). Growth in the supply area is predominantly new low and medium density residential and commercial greenfield developments.

Maximum demand for the supply area is expected to grow on average by 3.8% per annum during the next 10-year period, driven primarily by population growth (infill and greenfield residential development) and electrification. Given this growth, parts of the existing sub-transmission network, 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 (SBY & SHM), one sub-transmission network (being KTS-SBY-SHM-GSB-WND), and at least five 22 kV distribution feeders (SHM14, SBY24, SHM11, SBY23 & SBY32). Staged, targeted augmentations of the network are needed, to connect new customers and maintain current levels of supply reliability.

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: **Plumpton Plan**.
- Option 3: **Sydenham Plan;**
- Option 4: **Sunbury Plan;**
- Option 5: Battery Energy Storage System (BESS) Plan; and
- Option 6: Demand Management (DM) Plan.

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

Table ES–1-1: Summary of Cost-Benefit Analysis ($M Real 2024)

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	0.0	6
Option 2 – Plumpton Plan	74.0	64.9	129	64.3	3
Option 3 - Sydenham Plan	52.0	50.9	140	88.9	2
Option 4 - Sunbury Plan	**36.8**	**40.8**	**139**	**98.1**	**1**
Option 5 – BESS Plan	**0**	**72.5**	**75**	**2.5**	**5**
Option 6 – DM Plan	**0**	**33.0**	**75**	**42.0**	**4**

Preferred Option

The assessment demonstrates that the preferred network development plan is to implement Option 4 (Sunbury Plan) because this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred Option 4 provides a 20-year present value net market benefit of $98.1 million, with a present value of $35.4 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 analysis period.

The preferred network Option 4 to address the network limitations include the following project components**:**

Table 1-2: Option 4 - Sunbury Plan

Timing	Projects	Cost (Real 2024)	Limitation Addressed
2026	Install Regulator - SBY13	[redacted]	SBY13 voltage limit (ex ACR51070)
2026	New feeder SHM-013	[redacted]	SHM14 overload
2026	New feeder SBY-022	[redacted]	SHM11 overload
2026	New feeder SBY-014	[redacted]	SBY23 overload
2027	New feeder SBY-015	[redacted]	SBY24 overload
2027	Upgrade SBY No.1 transformer to 20/33MVA	[redacted]	SBY overload
	Upgrade SBY No.3 transformer to 20/33MVA		SBY & SHM overload
2027	New feeder SBY-031	[redacted]	SHM overload
2028	Load transfer SBY24 to SBY35	[redacted]	SBY24 overload
2029	Augment steel section - SBY24	[redacted]	SBY24 sw56781 fuse rating
			SBY24 sw51196 fuse rating
2030	Install Regulator - SBY23	[redacted]	SBY23 voltage limit (ex ACR55612)
Total		**$36.8 million**	
Present Value Total		**$35.4 million**	

The estimated total capital cost of Option 4 for JEN over 10-years to address the identified network limitations is $36.8 million ($2024, Real), of which $5.8 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 can have a slight change to the optimal timing of some projects in the development plan but does not change Option 4 as the preferred option.

Table ES-3: Option 4 - Sunbury Plan, project within FY2027-31 regulatory control period

Timing	Projects	Cost (Real 2024)[1]	Limitation Addressed
2026	Install Regulator - SBY13	[redacted]	SBY13 voltage limit (ex ACR51070)
2026	New feeder SHM-013	[redacted]	SHM14 overload
2026	New feeder SBY-022	[redacted]	SHM11 overload
2026	New feeder SBY-014	[redacted]	SBY23 overload
2027	New feeder SBY-015	[redacted]	SBY24 overload
2027	Upgrade SBY No.1 transformer to 20/33MVA	[redacted]	SBY overload
	Upgrade SBY No.3 transformer to 20/33MVA		SBY & SHM overload
2027	New feeder SBY-031	[redacted]	SHM overload
2028	Load transfer SBY24 to SBY35	[redacted]	SBY24 overload
2029	Augment steel section - SBY24	[redacted]	SBY24 sw56781 fuse rating
			SBY24 sw51196 fuse rating
2030	Install Regulator - SBY23	[redacted]	SBY23 voltage limit (ex ACR55612)
Total		**$30.9 million**	

[1] Three projects with optimal timing of 2026 have cost incurred in FY2026, total of $5.8M, which is outside the FY2027-2031 regulatory period.

1. Introduction

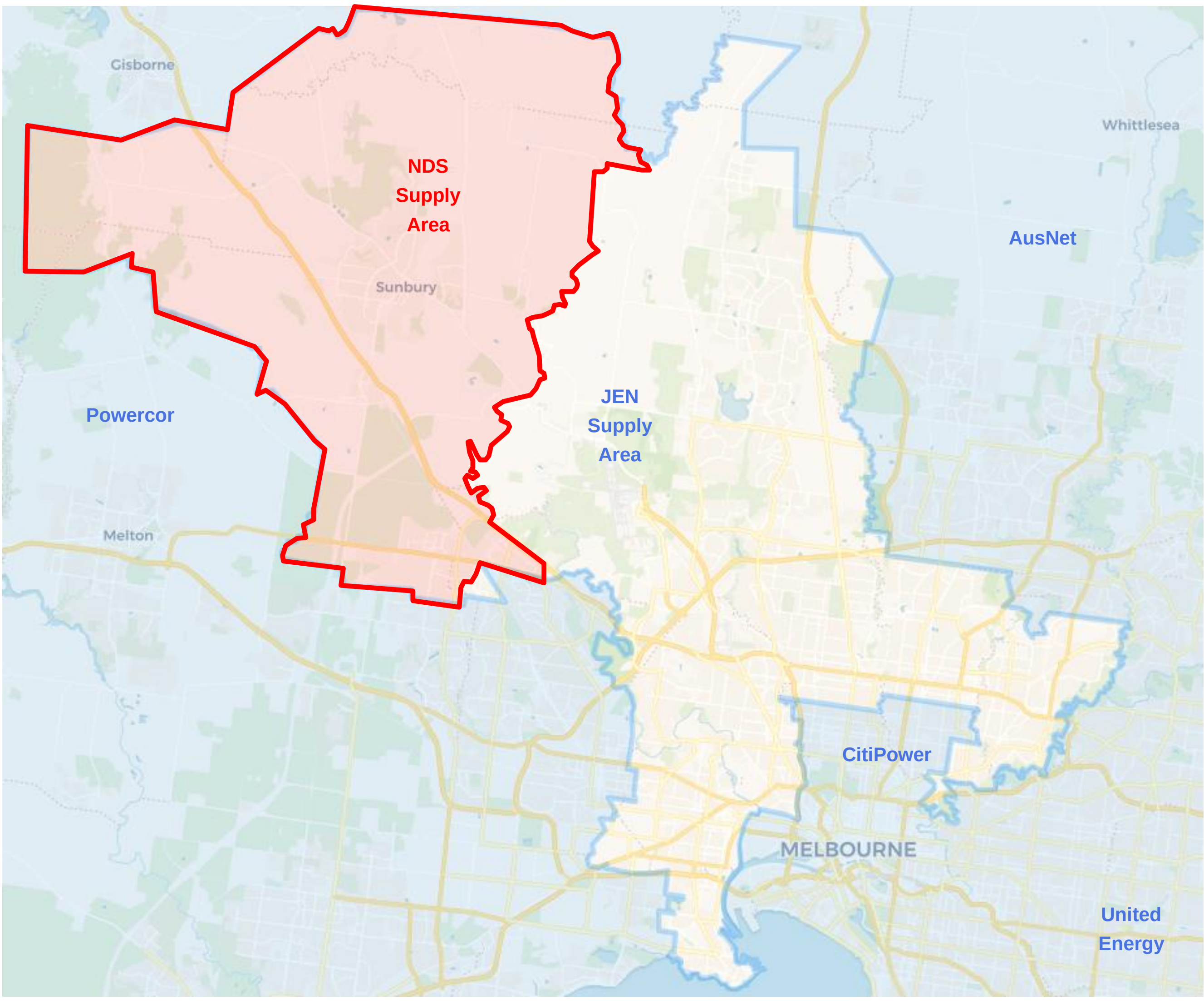
This chapter outlines the purpose of this NDS, provides an overview of the supply area, describes the general arrangement of the electricity network, and gives a brief overview of the network limitations in this area.

1.1 Purpose

Jemena 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 west of Deep Creek and Jacksons Creek, bordered to the west, north and south by the Powercor service area boundary, servicing the localities of Sunbury, Gisborne South, Clarkefield, Wildwood, Diggers Rest, Plumpton, Fraser Rise, Bonnie Brook, Hillside, Bulla, Sydenham, Calder Park and Taylors Lakes. It presents the current and emerging limitations within this supply area over a 10-year planning horizon, and articulates the need for investment, in order to address the identified network needs.

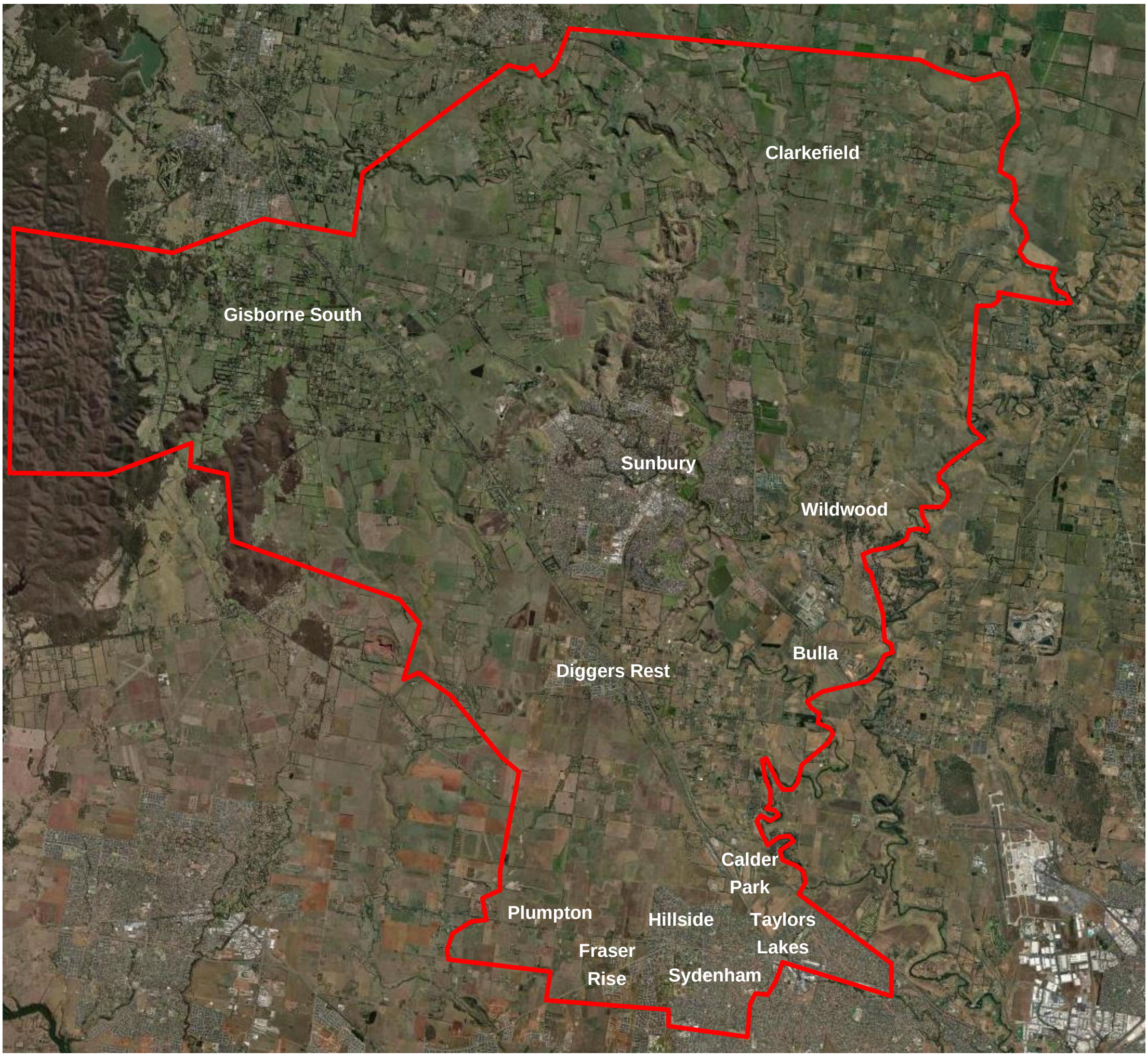
Figure 1-1 NDS Supply Area within the JEN Service Area



1.2 Supply Area Overview

The supply area covering the outer north-western Melbourne metropolitan area and fringe is a mix of rural, developed urbanised, and greenfield residential and commercial growth areas. It includes the motor racing precinct of Calder Park.

Figure 1-2 NDS Supply Area



The supply area covers parts of the Hume, Melton and Macedon Ranges city council municipal areas. In 2022, the supply area's population was 91,281. This is forecast to grow to 182,249 residents in 2046. This represents a forecast increase of 100% per cent on the current population (approximately 4.2% per annum).

Table 1-1: Supply Area Resident Population[2]

Suburb	Actual 2022	Forecast 2046	Increase	% Increase (pa)
Bulla / Wildwood (part)	381	579	198	2.2%
Clarkefield	351	517	166	2.0%
Gisborne South	894	1,210	316	1.5%
Sunbury	40,700	101,065	60,365	6.2%
Diggers Rest	6,408	12,716	6,308	4.1%
Plumpton area[3] (part)	7,665	29,970	22,305	12.1%
Hillside	16,137	16,506	369	0.1%
Sydenham	11,856	12,685	829	0.3%
Taylors Lakes (part)	6,889	7,000	112	0.1%
Calder Park	0	0	0	0.0%
TOTAL	**91,281**	**182,249**	**90,968**	**4.2%**

The largest increases in population are expected to occur in Sunbury, Plumpton area and Diggers Rest respectively, with the highest growth rate expected in the Plumpton 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[4] (eastern area), Macedon Ranges[5] (northern area), Melton[6] (west area) and Brimbank[7] (south area) City Councils' Planning Schemes as illustrated in Figure 1–3, Figure 1–4, Figure 1–5, Figure 1–6 respectively.

[2] See https://forecast.id.com.au/melton, https://forecast.id.com.au/brimbank, https://forecast.id.com.au/macedon-ranges, and https://forecast.id.com.au/hume.

[3] Includes part of Plumpton, Bonnie Brook and Fraser Rise.

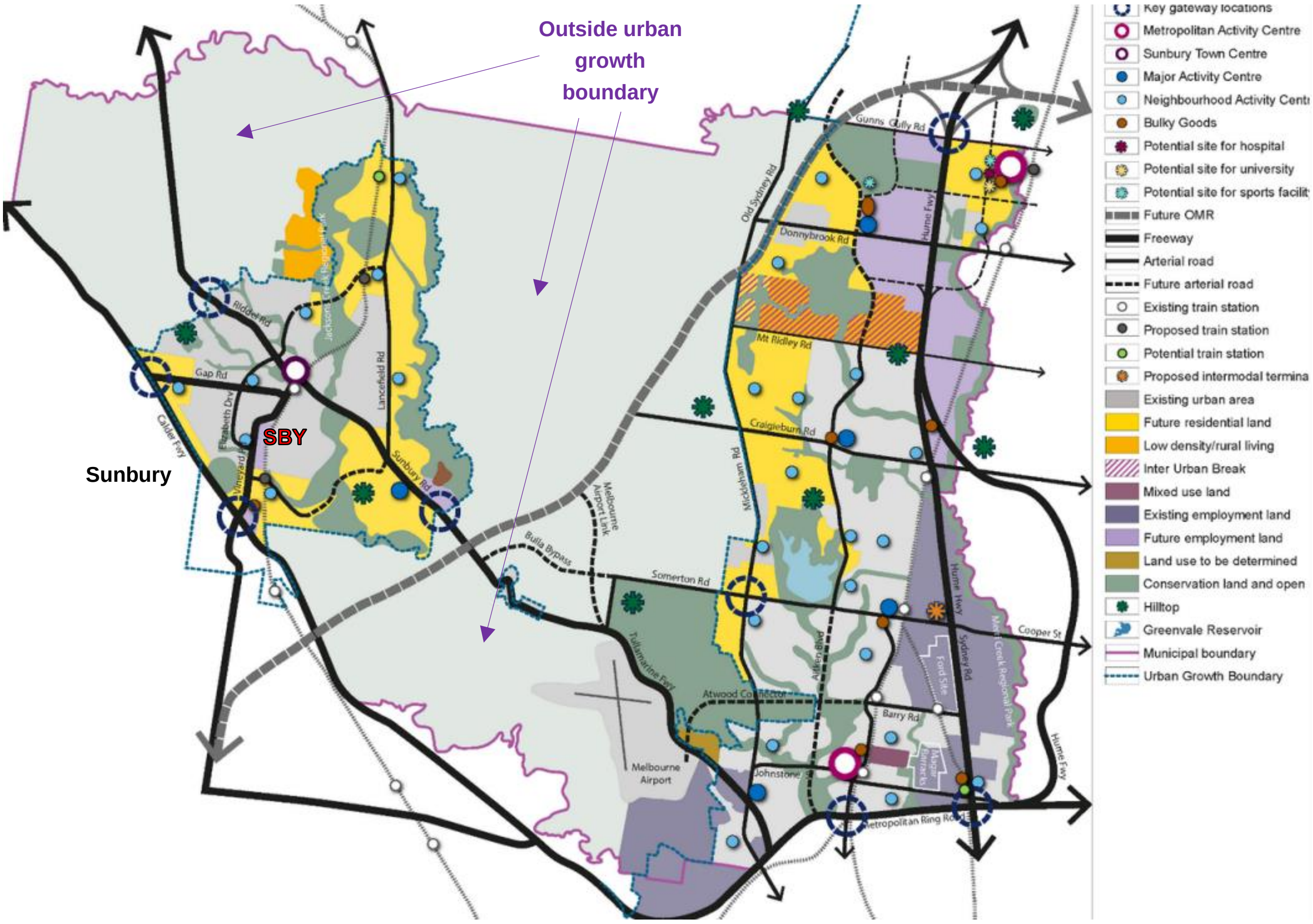
[4] See https://planning-schemes.app.planning.vic.gov.au/static/1695670541404/pdf/2907411.pdf

[5] See https://planning-schemes.app.planning.vic.gov.au/static/1695670949936/pdf/2670159.pdf

[6] See https://planning-schemes.app.planning.vic.gov.au/static/1695670267112/pdf/2832179.pdf

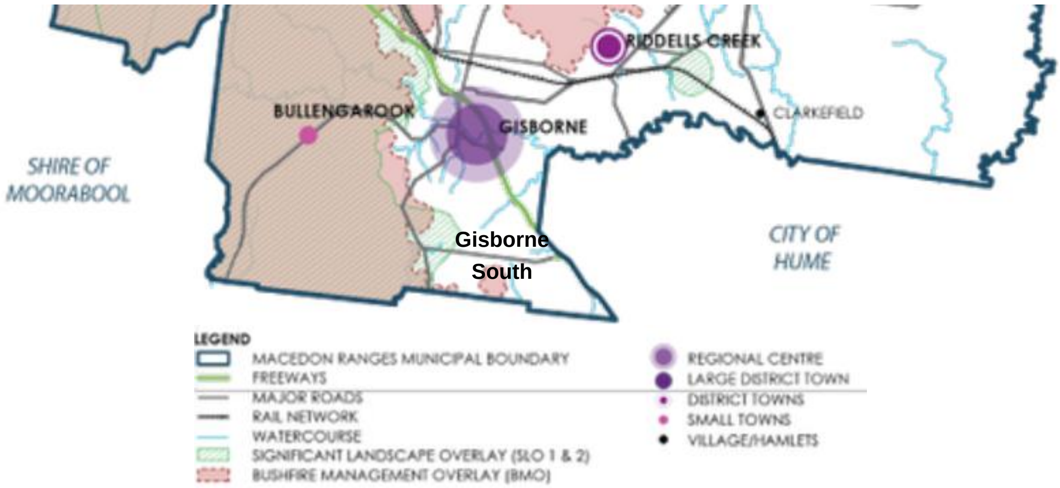
[7] See https://planning-schemes.app.planning.vic.gov.au/static/1695669960319/pdf/2753178.pdf

Figure 1–3: Hume Planning Scheme strategic framework plan (eastern area)



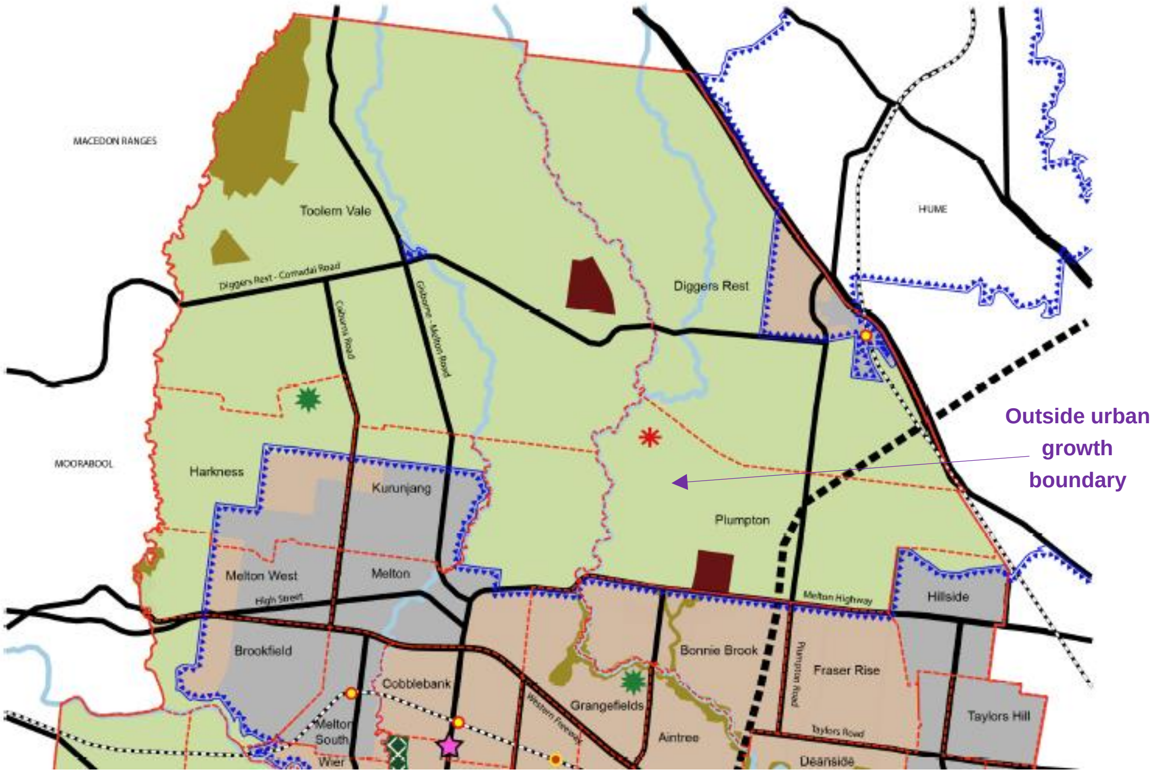
Source: Hume Planning Scheme

Figure 1–4: Macedon Ranges Planning Scheme strategic framework plan (northern area)



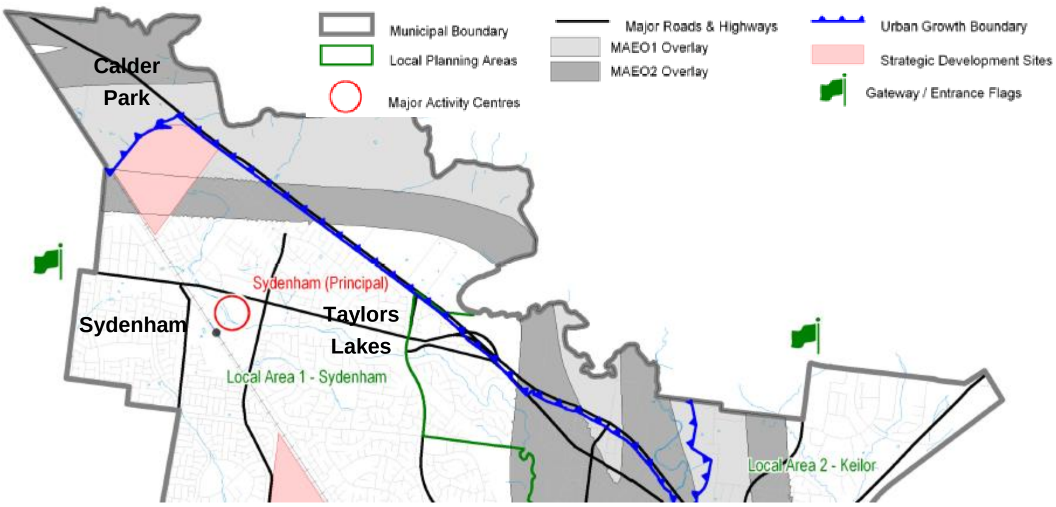
Source: Macedon Ranges Planning Scheme

Figure 1–5: Melton Planning Scheme strategic framework plan (western area)



Source: Melton Planning Scheme

Figure 1–6: Brimbank Planning Scheme strategic framework plan (southern area)



Source: Brimbank Planning Scheme

The supply area is serviced by our Sydenham (**SHM**), Sunbury (**SBY**), and part of Powercor's St Albans (**SA**) zone substations by a network of 22 kV distribution feeders. This supply area currently services over 36,000 electricity distribution customers.

Table 1-2: Supply Area Electricity Distribution Customers[8]

Sydenham (SHM) Zone Substation	Actual 2022	Sunbury (SBY) Zone Substation	Actual 2022	St Albans (SA) Zone Substation	Actual 2022
SHM11	3,110	SBY13	3,317	SA 02	49
SHM12	2,919	SBY34	1	SA 06	154
SHM14	3,987	SBY32	3,402	SA 10	43
SHM21	4,394	SBY12	1,953	SA 12	1,846
SHM22	2,382	SBY23	3,964		
SHM23	-	SBY24	3,111		
SHM24	1	SBY35	1,453		
16,793		**17,201**		**2,092**	
36,086					

Growth in population (infill and greenfield residential development) and electrification is expected to contribute to growth in electricity demand.

Maximum demand for the supply area is expected to grow on average by 3.8% per annum during the next 10-year period (2025-34).

Parts of the existing sub-transmission network, 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 (SBY & SHM), one sub-transmission network (being KTS-SBY-SHM-GSB-WND), and at least five 22 kV distribution feeders (SHM14, SBY24, SHM11, SBY23 & SBY32). Staged, targeted augmentations of the network are needed, to connect new customers and maintain current levels of supply reliability.

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

1.3 Network Overview

The NDS supply area is currently serviced by the following electricity distribution network assets:

- 2 x zone substations
    - 66/22 kV Sydenham Zone Substation (**SHM**)
    - 66/22 kV Sunbury Zone Substation (**SBY**)
- 4 x JEN-owned 66kV sub-transmission lines forming 1 sub-transmission loop[9] from one AusNet transmission terminal substation – Keilor (**KTS**)
    - KTS-SHM
    - KTS-SBY No.1
    - KTS-SBY No. 2
    - SHM-SBY
- 18 x 11 kV distribution feeders (excluding spare feeder circuit breakers)
    - 7 ex SHM – SHM11, SHM12, SHM14, SHM21, SHM22, SHM23, and SHM24.
    - 7 ex SBY – SBY13, SBY34, SBY32, SBY12, SBY23, SBY24, and SBY35.
    - 4 ex SA[10] – SA 02, SA 06, SA 10, and SA 12.

Single line diagrams, network area maps and details of the existing network is provided below.

[9] Comprising SHM and SBY zone substations, with Powercor's Gisborne (GSB) and Woodend (WND) Zone Substations supplied downstream from SBY.

[10] 'SA' is Powercor's St Albans Zone Substation which supplies four 22 kV distribution feeders into the supply area.

1.3.1 Zone substation network

The supply boundaries (shaded) of the zone substations contained within the NDS supply area are shown in Figure 1-7, showing the location of the zone substations and their sub-transmission lines (purple).

Figure 1-7 Zone Substation Boundaries

[redacted]

1.3.1.1 Sydenham (SHM) zone substation

SHM is a summer peaking partially indoor zone substation having two 66/22 kV 20/33 MVA transformers. Under system normal conditions, the two transformers are operated in parallel as one group. SHM has the ability to expand to three transformers in future. SHM has seven in-service 22 kV feeders and one spare 22 kV circuit breaker for additional future feeders (SHM13), on the existing 22 kV buses.

Within the NDS supply area, SHM services the localities of Diggers Rest, Calder Park, Sydenham, Taylors Lakes, Plumpton area and Hillside, supplying 16,793 customers. The SHM single line diagram and aerial view is shown in Figure 1-8 and Figure 1-9 respectively.

Figure 1-8 SHM Single Line Diagram

[redacted]

Figure 1-9 SHM Aerial View

1.3.1.2 Sunbury (SBY) zone substation

SBY is a summer peaking partially indoor zone substation having one 66/22 kV 20/33 MVA transformers (No.2) and two 66/22 kV 10/16 MVA transformers (No.1 and No.3). Under system normal conditions, the three transformers are operated in parallel as one group. SBY has seven in-service 22 kV feeders, and seven spare 22 kV circuit breaker bays for additional future feeders (SBY33, SBY31, SBY25, SBY22, SBY21, SBY15, SBY14), from the three existing 22 kV buses. SBY has the ability to accommodate a 2nd and 3rd 20/33 MVA transformer in future to replace the two existing smaller transformers. SBY operates with a 66 kV ring bus in order to supply the two Powercor zone substations, Gisborne (GSB) and Woodend (WND).

Within the NDS supply area, SBY services the localities of Sunbury, Gisborne South, Clarkefield, Wildwood, and parts of Bulla, supplying 17,201 customers. Figure 1-10 and Figure 1-11 show the single line diagram and aerial view of SBY, respectively.

Figure 1-10 SBY Single Line Diagram

[redacted]

Figure 1-11 SBY Aerial View

1.3.2 Sub-transmission network

One sub-transmission network services the area, at 66 kV from KTS Bus group 34 as shown in Figure 1-12.

Figure 1-12: 66kV Sub-transmission Lines in the Supply Area - Schematic

[redacted]

The KTS-SBY-SHM-GSB-WND 66 kV sub-transmission network supplies approximately 58,033 customers (33,994 JEN from SHM and SBY, and 24,039 Powercor from GSB and WND) from three 66 kV lines from KTS. GSB and WND are supplied by two 66 kV lines from SBY. Figure 1-13 shows the network schematic diagram.

Figure 1-13: KTS-SBY-SHM-GSB-WND 66 kV Sub-transmission Network

[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 1-14.

Multiple 22 kV inter-feeder tie points exist between JEN feeders on SHM, SBY, and SA (via feeders SHM11 - SBY13, SHM11 - SBY32, SHM24 - SA 06, SHM24 - SA 10 [11], and SHM21 – SA 12).

[11] SA 10 feeder only available for contingency fault restoration.

Figure 1-14: 22 kV Distribution Feeders

[redacted]

2. Identified Need

The key driver for an asset management intervention in the NDS supply area relates to existing and emerging asset utilisation limitations associated with maximum demand growth, reducing the spare capacity available within the distribution network (**reliability**).

2.1 Network Utilisation

Maximum demand for the supply area is expected to grow on average by 3.8% 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 high-rise apartment development, and increased electric vehicle usage and electrification of gas across the area.

Parts of the existing sub-transmission networks, 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 (SBY & SHM), one sub-transmission network (being KTS-SBY-SHM-GSB-WND), and at least five 22 kV distribution feeders (SHM14, SBY24, SHM11, SBY23 & SBY32). 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)
SBY	65.0	65.0	38.0	38.0
SHM	66.0	66.0	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
KTS-SBY-SHM-GSB-WND	**290**	**337**	**Overall N Rating**
	180	**216**	**Overall N-1 Rating**
	96.0	116.6	KTS-SBY No.1
	94.3	100.6	KTS-SBY No.2
	117.2	128.0	KTS-SHM
	117.2	128.0	SBY-SHM

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
SHM11	14.3	14.3	SBY12	14.3	14.3
SHM12	14.3	14.3	SBY13	12.5	14.1
SHM14	14.3	14.3	SBY23	14.3	14.3
SHM21	14.3	14.3	SBY24	14.3	14.3
SHM22	14.3	14.3	SBY32	14.3	14.3
SHM23	14.3	14.3	SBY34	14.3	14.3
SHM24	14.3	14.3	SBY35	14.3	14.3
SA 02	5.3	7.4	SA 10 [12]	0.0	0.0
SA 06	12.0	12.8	SA 12	8.8	12.8
sw51196 (SBY24)[13]	1.5	1.5	ACR51070 (SBY13)[14]	2.0	2.0
sw56781 (SBY24)[13]	0.6	0.6	ACR55612 (SBY23)[14]	3.0	3.0

2.1.2 Historical Maximum Demand

Table 2-4 presents the historical actual summer maximum demand on our zone substation and sub-transmission 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
SBY	**65.0**	**38.0**	45.6	39.2	40.9	45.3
SHM	**66.0**	**38.0**	45.6	34.3	39.2	39.8
KTS-SBY-SHM-GSB-WND	**290**	**180**	146.0	117.7	128.2	136.1

This table illustrates that SBY and SHM have historically been highly utilised zone substations.

[12] SA 10 feeder only available for contingency fault restoration.

[13] Fuse rating and steel conductor limited.

[14] Voltage limited.

Table 2-5 present the historical actual summer maximum demand on our 11 kV distribution feeder assets in the area. Values highlighted in red exceed the voltage limits and those in **bold red** exceed the (N) rating.

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

Feeder	Rating	2020	2021	2022	2023	Feeder	Rating	2020	2021	2022	2023
SHM11	**14.3**	6.1	5.4	6.5	3.5	**SBY12**	**14.3**	7.5	6.3	6.1	6.6
SHM12	**14.3**	9.2	6.9	8.0	8.1	**SBY13**	**12.5**	7.4	6.2	6.5	6.8
SHM14	**14.3**	9.3	7.8	9.5	10.5	**SBY23**	**14.3**	9.9	8.1	9.1	9.7
SHM21	**14.3**	10.0	8.2	8.8	8.9	**SBY24**	**14.3**	8.5	8.2	7.8	9.0
SHM22	**14.3**	6.5	5.0	5.4	5.8	**SBY32**	**14.3**	8.0	6.4	6.1	10.6
SHM23	**14.3**	0.0	0.0	0.0	1.8	**SBY34**	**14.3**	3.4	8.0	7.5	3.8
SHM24	**14.3**	6.8	5.2	6.2	6.6	**SBY35**	**14.3**	3.8	3.2	3.5	3.6
SA 02	**5.3**	0.3	0.2	0.4	0.5	**SA 10**	**0.0**	0.0	0.0	0.0	0.0
SA 06	**12.0**	0.7	0.5	0.4	0.4	**SA 12**	**8.8**	4.0	3.4	3.3	3.5
SW 51196	**1.5**	0.8	0.8	0.7	0.9	**ACR 51070**	**2.0**	2.2	1.8	1.9	2.6
SW 56781	**0.6**	0.3	0.2	0.2	0.3	**ACR 55612**	**3.0**	2.2	1.8	2.0	2.1

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**). 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.

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** exceeding the (N) rating. SBY is forecast to exceed its (N) rating in 2033.

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
SBY	**65.0**	**38.0**	51.5	54.7	57.1	59.0	60.2	61.5	63.1	64.7	**66.3**	**67.6**
SHM	**66.0**	**38.0**	46.6	49.4	51.9	53.9	55.2	56.8	58.5	60.4	62.2	63.8
KTS-SBY-SHM-GSB-WND	**290**	**180**	155	160	164	169	185	189	195	200	206	210

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** exceeding the (N) rating. SBY and SHM are forecast to exceed their (N) rating in 2031 and 2033, respectively.

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
SBY	**65.0**	**38.0**	44.4	48.7	51.9	54.6	56.4	58.4	59.9	61.5	63.0	64.5
SHM	**66.0**	**39.6**	35.7	39.4	42.8	45.6	47.7	49.9	51.7	53.4	55.2	56.9
KTS-SBY-SHM-GSB-WND	**337**	**216**	126	135	142	150	167	173	179	184	189	194

Table 2-8 presents the distribution feeder 10% PoE summer maximum demand forecast for the forward 10-year planning period. Values highlighted red exceed the voltage limits and those 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
SHM11	**14.3**	5.6	7.8	10.1	11.7	12.5	13.2	13.8	14.3	**14.7**	**15.1**
SHM12	**14.3**	8.6	8.7	8.8	8.9	9.0	9.2	9.5	9.8	10.1	10.4
SHM14	**14.3**	**14.6**	**17.1**	**18.8**	**20.1**	**20.8**	**21.5**	**22.2**	**22.9**	**23.6**	**24.2**
SHM21	**14.3**	10.7	11.5	12.0	12.1	12.3	12.6	13.0	13.4	13.8	14.2
SHM22	**14.3**	6.1	6.1	6.2	6.3	6.4	6.6	6.8	7.0	7.2	7.4
SHM23	**14.3**	2.0	2.0	2.0	2.0	2.0	2.1	2.2	2.2	2.3	2.4
SHM24	**14.3**	5.9	5.9	5.9	5.9	6.0	6.2	6.4	6.6	6.8	7.0
SBY12	**14.3**	7.2	7.4	7.7	7.8	7.9	8.1	8.3	8.5	8.7	8.9
SBY13	**12.5**	7.2	7.4	7.6	7.7	7.8	8.0	8.2	8.4	8.6	8.8
SBY23	**14.3**	10.7	11.1	11.3	11.5	11.7	12.0	12.3	12.6	12.9	13.1
SBY24	**14.3**	8.5	11.6	14.1	**16.0**	**16.8**	**17.5**	**18.0**	**18.4**	**18.9**	**19.3**
SBY32	**14.3**	13.4	**15.2**	**16.0**	**16.6**	**17.0**	**17.5**	**17.9**	**18.4**	**18.8**	**19.2**
SBY34	**14.3**	3.2	3.2	3.2	3.2	3.2	3.3	3.4	3.5	3.6	3.6
SBY35	**14.3**	6.5	6.5	6.5	6.5	6.6	6.7	6.9	7.1	7.2	7.4

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
SA 02	**5.3**	1.0	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0
SA 06	**12.0**	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SA 10	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SA 12	**8.8**	3.5	3.4	3.4	3.4	3.4	3.5	3.5	3.6	3.6	3.6
ACR51070	**2.0**	**2.8**	**2.8**	**2.8**	**2.9**	**3.0**	**3.1**	**3.3**	**3.4**	**3.6**	**3.8**
ACR55612	**3.0**	2.3	2.4	2.5	2.5	2.6	2.6	2.7	2.8	2.8	**3.3**
sw51196	**1.5**	1.0	1.4	**1.7**	**1.9**	**2.0**	**2.1**	**2.1**	**2.2**	**2.2**	**2.3**
sw56781	**0.6**	0.4	0.5	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**	**0.9**	**0.9**	**0.9**

Table 2-9 presents the distribution feeder 10% PoE winter maximum demand forecast for the forward 10-year planning period. Values highlighted in red exceed the voltage limits and those 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
SHM11	**14.3**	5.8	8.7	11.6	13.8	**15.1**	**16.2**	**17.0**	**17.6**	**18.2**	**18.7**
SHM12	**14.3**	5.9	6.2	6.4	6.6	6.8	7.1	7.4	7.6	7.9	8.1
SHM14	**14.3**	9.4	11.3	12.8	13.9	**14.6**	**15.5**	**16.0**	**16.5**	**17.1**	**17.6**
SHM21	**14.3**	7.6	8.4	9.0	9.3	9.6	10.0	10.4	10.7	11.1	11.4
SHM22	**14.3**	4.5	4.7	4.8	5.0	5.2	5.4	5.6	5.8	6.0	6.2
SHM23	**14.3**	1.9	2.0	2.0	2.1	2.1	2.3	2.3	2.4	2.5	2.6
SHM24	**14.3**	6.0	6.0	6.0	6.0	6.1	6.2	6.3	6.4	6.5	6.6
SBY12	**14.3**	6.2	6.7	7.0	7.2	7.4	7.6	7.8	8.1	8.3	8.5
SBY13	**14.1**	7.1	7.5	7.9	8.2	8.4	8.8	9.0	9.3	9.5	9.8
SBY23	**14.3**	9.9	10.6	11.1	11.5	11.9	12.4	12.8	13.1	13.5	13.8
SBY24	**14.3**	6.8	9.4	11.8	13.6	**14.6**	**15.5**	**16.0**	**16.4**	**16.8**	**17.2**
SBY32	**14.3**	11.3	13.2	14.2	**15.1**	**15.7**	**16.5**	**16.9**	**17.4**	**17.9**	**18.3**
SBY34	**14.3**	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.9	3.9

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
SBY35	**14.3**	5.8	5.9	6.0	6.1	6.3	6.4	6.6	6.8	7.0	7.2
SA 02	**7.4**	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
SA 06	**12.8**	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
SA 10	**0.0**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SA 12	**12.8**	2.9	3.0	3.0	3.1	3.1	3.2	3.3	3.3	3.4	3.4
ACR51070	**2.0**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.9**	**3.0**	**3.2**	**3.3**	**3.4**
ACR55612	**3.0**	2.2	2.3	2.5	2.5	2.6	2.7	2.8	2.9	3.0	3.0
sw51196	**1.5**	0.8	1.1	1.4	**1.6**	**1.7**	**1.8**	**1.9**	**1.9**	**2.0**	**2.0**
sw56781	**0.6**	0.3	0.4	0.6	0.6	**0.7**	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**

2.2 REFCL Performance

With the development of new greenfield estates in the supply area having HV underground feeders, the increased cable capacitance is expected to the deteriorate the performance of Rapid Earth Fault Current Limiter (REFCL)-protected feeders in the area, that is, feeders supplied by the SHM REFCL zone substation.

Table 2-10 presents the forecast levels of cable capacitance current (Ico) expected at SHM over the next 10-years. The limit of Ico on SHM is currently 320A and this is forecast to be exceeded in 2024. There is however a committed project underway to upgrade the REFCL rating at SHM to 400A in 2025, and as such the rating in Table 2-10 is assumed to be 400A.

Table 2-10: Forecast Ico at SHM (Amps)

Rating	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
400	320.0	338.5	350.5	359.4	364.1	365.8	367.5	369.1	370.8	372.4

The SHM REFCL is forecast to be operating within its Ico limits for the entire 10-year forecast.

2.3 Summary of Network Limitations

This NDS will assess the technical and economic viability of solutions to alleviate the network utilisation identified above. 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 solutions

Network Asset	Limitation	From	Screening of credible network solutions to address the need[15]
SBY	N-1 capacity	Existing	Upgrade SBY No.1 transformer to 20/33MVA
	N capacity	2033	Upgrade SBY No.3 transformer to 20/33MVA

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

Network Asset	Limitation	From	Screening of credible network solutions to address the need[15]
			BESS and/or demand management in SBY 22 kV distribution network
SHM	N-1 capacity	Existing	New feeder SBY-022 3rd 66/22 kV transformer at SHM New 66/22 kV REFCL zone substation at PLN & New feeders PLN11 and PLN12 Upgrade SBY No.1 transformer to 20/33MVA & Upgrade SBY No.3 transformer to 20/33MVA & New feeder SBY-031 Load transfers to SBY and/or PLN BESS and/or demand management in SHM 22 kV distribution network
KTS-SBY-SHM-GSB-WND	N-1 capacity	2029	Do Nothing – EUE risk is negligible
SHM11	N capacity	2029	New feeder SBY-022 BESS and/or demand management in SHM 11 22 kV distribution network
SHM14	N capacity	2029	New feeder SHM-013 New 66/22 kV REFCL zone substation at PLN & New feeders PLN11 and PLN12 3rd 66/22 kV transformer at SHM & New feeders SHM31 and SHM32 BESS and/or demand management in SHM 14 22 kV distribution network
SBY23	N-1 capacity	2026	New feeder SBY-014 BESS and/or demand management in SBY 23 22 kV distribution network
SBY24	N capacity	2028	Load transfers SBY24 to SBY35 Reconfigure feeder SBY24 New feeder SBY-015 BESS and/or demand management in SBY 24 22 kV distribution network
ACR51070	Voltage limit	Existing	Install Regulator - SBY13
ACR55612	Voltage limit	2033	Install Regulator - SBY23
sw51196	Fuse rating	2027	Augment steel section - SBY24 BESS and/or demand management in SBY 24 22 kV distribution network
sw56781	Fuse rating	2027	

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.

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.

Not withstanding 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. Applying this methodology to distributed storage, we determined that the installed costs[16] of $72.5 million[17] is greater than the $40.8 million installed costs of the preferred network option. By comparison, for a demand response solution, we determined that the costs of $1.65 million pa[18] is comparable to the network augmentation deferral benefit of $2.1 million pa[19]. Whilst this not the

[16] 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.

[17] Installed cost of $500/kWh x $139 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $72.5 million.

[18] Dispatch cost of $10/kWh x $139 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $1.45 million pa plus $0.2 million pa of fixed ongoing costs.

[19] Preferred network option cost of 40.8 million present value of capital and O&M costs x 5.18% discount rate = $2.1 million pa.

preferred approach for storage, demand response could be a preferred approach for some of the projects in the network development program, only if all four credibility criteria are met - this has yet to be tested with the market.

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 EUE for all the solutions analysed in this document:

- Value of Customer Reliability (VCR) of $47,905 per MWh (nominal).
- 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 2.2.

Table 4-1 details the zone substation and sub-transmission 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	SBY	SHM	KTS-SBY-SHM-GSB-WND	Total
2025	7.9	0.2	0.0	**8.0**
2026	9.2	0.3	0.0	**9.5**
2027	18.5	0.6	0.0	**19.0**
2028	28.5	1.2	0.0	**29.7**
2029	37.1	2.2	0.0	**39.3**
2030	47.5	4.4	0.0	**51.9**
2031	57.6	6.9	0.0	**64.5**
2032	69.0	10.2	0.0	**79.2**
2033	82.0	13.9	0.0	**95.9**
2034	96.2	18.2	0.1	**114.4**

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	SHM11	SHM14	SBY23	SBY24	ACR51070	ACR55612	sw51196	sw56781	Total
2025	15.4	0.6	3.3	0.0	55.5	0.0	0.0	0.0	**74.8**
2026	111.3	14.1	22.3	0.9	65.7	0.0	0.0	0.0	**214.3**
2027	227.1	58.1	51.2	9.9	75.8	0.0	0.0	0.0	**422.1**
2028	311.8	130.6	76.3	32.1	93.3	0.0	2.5	1.0	**647.7**
2029	356.1	180.9	90.1	57.0	129.8	0.1	15.9	6.4	**836.2**
2030	408.3	237.5	109.4	98.3	199.7	1.4	48.4	19.4	**1,122**

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

Table 4-3 details the zone substation and sub-transmission 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 ($k, Real 2024) – Option 1

Asset	SBY	SHM	KTS-SBY-SHM-GSB-WND	Total
2025	377	8	0	385
2026	439	15	0	454
2027	885	27	0	912
2028	1,366	57	0	1,423
2029	1,777	108	0	1,884
2030	2,275	210	0	2,485
2031	2,759	333	0	3,092
2032	3,307	488	0	3,795
2033	3,927	668	1	4,596
2034	4,607	871	3	5,482

The value of the EUE risk on KTS-SBY-SHM-GSB-WND is insufficient to justify any investment at the sus-transmission level.

Table 4-4 details the distribution feeder 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 ($k, Real 2024) – Option 1

Asset	SHM11	SHM14	SBY23	SBY24	ACR 51070	ACR 55612	Sw 51196	Sw 56781	Total
2025	738	27	158	0	2,661	0	0	0	3,584
2026	5,331	676	1,070	42	3,149	0	0	0	10,268
2027	10,880	2,784	2,452	473	3,633	0	0	0	20,222
2028	14,935	6,259	3,657	1,540	4,469	0	122	49	31,031
2029	17,057	8,665	4,314	2,730	6,218	7	763	305	40,059
2030	19,562	11,378	4,922	4,424	8,988	62	2,178	871	52,385

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

Option	High-Level Description	Ability to address identified network need
Option 1 Do Nothing	This is the base case, assuming no additional expenditure in the NDS supply area.	Nil
Option 2 Plumpton Plan	Install a new 66/22 kV 20/33 MVA REFCL zone substation PLN in the Plumpton area with new feeders and other feeder works at SHM and SBY. Upgrade SBY No.1 & 3 transformers.	Fully addresses overload risk at SHM. Fully addresses overload risk at SBY. No change in overload risk on KTS-SBY-SHM loop. Fully addresses all feeders overload & voltage risk.
Option 3 Sydenham Plan	Install a 3rd 66/22 kV 20/33 MVA transformer at with new feeders and other feeder works at SHM and SBY. Upgrade SBY No.1 & 3 transformers.	Fully addresses overload risk at SHM. Fully addresses overload risk at SBY. No change in overload risk on KTS-SBY-SHM loop. Fully addresses all feeders overload & voltage risk.
Option 4 Sunbury Plan	Upgrade the existing No.1 and No.3 66/22 kV transformers at SBY to 20/33 MVA with new feeders and other feeder works at SHM and SBY.	Partially addresses overload risk at SHM. Partially addresses overload risk at SBY. No change in overload risk on KTS-SBY-SHM loop. Fully addresses all feeders overload & voltage risk.
Option 5 BESS Plan	40 MW / 160 MWh BESS ramp up over 10 years, distributed across SBY & SHM 22 kV feeders.	Partially addresses overload risk at SHM. Partially addresses overload risk at SBY.

Option 6 DM Plan	40 MW / 160 MWh DM ramp up over 10 years, distributed across SBY & SHM 22 kV feeders.	No change in overload risk on KTS-SBY-SHM loop. Fully addresses all feeders overload & voltage risk.

Table 5-2 itemises the credible 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 Limitation</th><th>Option 1
Do Nothing</th><th>Option 2
PLN</th><th>Option 3
SHM</th><th>Option 4
SBY</th></tr>
<tr><td>SBY</td><td rowspan="12">Nil.</td><td colspan="3">8.4.1 Upgrade SBY No.1 transformer to 20/33MVA
8.4.2 Upgrade SBY No.3 transformer to 20/33MVA</td></tr>
<tr><td>SHM</td><td>8.2.1 New 66/22 kV REFCL zone substation at PLN
Load transfer from SHM to PLN (20 MVA)[20]</td><td>8.3.1 3rd 66/22 kV transformer at SHM</td><td>8.4.3 New feeder SBY-031
Load transfer from SHM to SBY (10 MVA)[21]</td></tr>
<tr><td>KTS-SBY-SHM-GSB-WND</td><td colspan="3">Nil – Insufficient market benefits.</td></tr>
<tr><td>SHM11</td><td colspan="3">8.1.6 New feeder SBY-022
Load transfer from SHM to SBY (7 MVA)[22]</td></tr>
<tr><td rowspan="2">SHM14</td><td colspan="3">8.1.1 New feeder SHM-013</td></tr>
<tr><td>8.2.2 New feeders PLN11 and PLN12</td><td>8.3.2 New feeders SHM31 and SHM32</td><td>8.4.3 New feeder SBY-031</td></tr>
<tr><td>SBY23</td><td colspan="3">8.1.7 New feeder SBY-014</td></tr>
<tr><td>SBY24</td><td colspan="3">Load transfers SBY24 to SBY35
8.1.8 New feeder SBY-015</td></tr>
<tr><td>ACR51070 (SBY13)</td><td colspan="3">8.1.3 Install Regulator - SBY13</td></tr>
<tr><td>ACR55612 (SBY23)</td><td colspan="3">8.1.5 Install Regulator - SBY23</td></tr>
<tr><td>sw51196 (SBY24)</td><td colspan="3" rowspan="2">8.1.4 Augment steel section - SBY24</td></tr>
<tr><td>sw56781 (SBY24)</td></tr>
</table>

[20] SHM14 to PLN11; SHM13 & SHM22 to PLN12.

[21] SHM11 to SBY31.

[22] SHM11 to SBY14.

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 (Real 2024)

Credible Network Solutions	Scope of Work Section	Option	Capital Cost ($M)	Annual Cost ($k pa)[23]	Network Limitation	Optimum Timing[24]
New feeder SHM-013	8.1.1	2,3,4	[redacted]	[redacted]	SHM14	2026
Install Regulator - SBY13	8.1.3	2,3,4	[redacted]	[redacted]	ACR51070	2026
Augment steel section - SBY24	8.1.4	2,3,4	[redacted]	[redacted]	sw51196 sw56781	2029
Install Regulator - SBY23	8.1.5	2,3,4	[redacted]	[redacted]	ACR55612	2030
New feeder SBY-022	8.1.6	2,3,4	[redacted]	[redacted]	SHM11	2026
New feeder SBY-014	8.1.7	2,3,4	[redacted]	[redacted]	SBY23	2026
New feeder SBY-015	8.1.8	2,3,4	[redacted]	[redacted]	SBY24	2027
New 66/22 kV REFCL zone substation at PLN	8.2.1	2	[redacted]	[redacted]	SHM	2035
New feeders PLN11 and PLN12	8.2.2	2	[redacted]	[redacted]	SHM14	2035
3rd 66/22 kV transformer at SHM	8.3.1	3	[redacted]	[redacted]	SHM	2033
New feeders SHM31 and SHM32	8.3.2	3	[redacted]	[redacted]	SHM14	2033
Upgrade SBY No.1 transformer to 20/33MVA	8.4.1	2,3,4	[redacted]	[redacted]	SBY	2027
Upgrade SBY No.3 transformer to 20/33MVA	8.4.2				SBY & SHM	
New feeder SBY-031	8.4.3	4	[redacted]	[redacted]	SHM14	2027

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. The incremental annual O&M expenditure is estimated at 1% of the capital costs within each option. Present values are calculated over an economic analysis period of 20 years.

[23] Based on 5.18% discount rate.

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

Table 5-4: Summary of Option Capital Costs ($M Real 2024)

Capital Cost	Option 1	Option 2	Option 3	Option 4
Option total capital cost	**0.0**	**73.7**	**51.7**	**36.9**
PV of total capital cost	0.0	56.6	44.2	35.6
PV of O&M cost	0.0	8.0	6.5	5.4
PV of option total capital and O&M cost	**0.0**	**64.6**	**50.6**	**40.9**

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, and Table 2-9.

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.
- Deterioration of supply reliability due to capacity shortfall; and
- Intangible costs to Jemena arising from negative publicity due to longer supply restoration time during and following hot weather events.

Table 5-5 presents the new ratings of the credible solutions applied 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 Ratings Before and After Planned Works (MVA)[25]

Asset	Option	Before	After	Solution Applied
SBY	2,3,4	38.0	76.0	8.4.1 & 8.4.2
SBY	Nil	38.0	49.0	8.4.1
SHM	3	38.0	76.0	8.3.1
PLN	2	0.0	33.0 [26]	8.2
SBY31	4	0.0	14.3	8.1.8
SBY15	4	0.0	14.3	8.1.8
SHM31	3	0.0	14.3	8.3.2
SHM32	3	0.0	14.3	8.3.2
SHM33	3	0.0	14.3	8.3.2
PLN11	2	0.0	14.3	8.2.2
PLN12	2	0.0	14.3	8.2.2
PLN13	2	0.0	14.3	8.2.2
ACR 51070 (SBY13)	2,3,4	2.0	5.7	8.1.3
SHM13	2,3,4	0.0	14.3	8.1.1
SBY14	2,3,4	0.0	14.3	8.1.6
SBY22	2,3,4	0.0	14.3	8.1.7
ACR 55612 (SBY23)	2,3,4	3.0	9.0	8.1.5
sw 51196 (SBY24)	2,3,4	1.5	11.0	8.1.4
sw 56781 (SBY24)	2,3,4	0.6	11.0	8.1.4
PLN REFCL	2	Nil	320 Amps (Bus 1)	8.2

Table 5-6 presents the 10% PoE summer maximum demand zone substation and sub-transmission network 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 and are an identified network limitation with red exceeding the (N-1) rating and **bold** exceeding the (N) rating.

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

[26] Single transformer zone substation – N nameplate rating.

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

Asset	Option	New Rating	2026	2027	2028	2029	2030	2031	2032	2033	2034
SBY	**2,3**	**76.0**	61.7	64.1	66.0	67.2	68.5	70.1	71.7	73.3	74.6
SBY	**4**	**76.0**	71.7	74.1	76.0	77.2	78.5	80.1	81.7	83.3	84.6
SHM	**2**	**38.0**	22.4	24.9	26.9	28.2	29.8	31.5	33.4	35.2	36.8
SHM	**3**	**76.0**	42.4	44.9	46.9	48.2	49.8	51.5	53.4	55.2	56.8
SHM	**4**	**38.0**	32.4	34.9	36.9	38.2	39.8	41.5	43.4	45.2	46.8
PLN	**2**	**33.0** [27]	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0

Table 5-7 presents the 10% PoE winter maximum demand zone substation and sub-transmission network 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 and are an identified network limitation with red exceeding the (N-1) rating and **bold** exceeding the (N) rating.

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

Asset	Option	New Rating	2026	2027	2028	2029	2030	2031	2032	2033	2034
SBY	**2,3**	**79.2**	55.7	58.9	61.6	63.4	65.4	66.9	68.5	70.0	71.5
SBY	**4**	**79.2**	65.7	68.9	71.6	73.4	75.4	76.9	78.5	80.0	81.5
SHM	**2**	**39.6**	12.4	15.8	18.6	20.7	22.9	24.7	26.4	28.2	29.9
SHM	**3**	**79.2**	32.4	35.8	38.6	40.7	42.9	44.7	46.4	48.2	49.9
SHM	**4**	**39.6**	22.4	25.8	28.6	30.7	32.9	34.7	36.4	38.2	39.9
PLN	**2**	**33.0** [27]	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0

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 now. Assets not listed have the same forecast as Option 1 detailed in Table 2-8.

[27] Single transformer zone substation – N nameplate rating.

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

Feeder	Option	New Rating	2026	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
SBY13	**2,3,4**	**12.5**	4.4	4.6	4.7	4.8	5.0	5.2	5.4	5.6	5.8	3 MVA to SBY22
SBY14	**2,3,4**	**14.3**	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7 MVA from SHM11
SBY15	**2,3,4**	**14.3**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11 MVA from SBY24
SBY22	**2,3,4**	**14.3**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	3 MVA from SBY13 5 MVA from SBY32 4 MVA from SBY23
SBY23	**2,3,4**	**14.3**	7.1	7.3	7.5	7.7	8.0	8.3	8.6	8.9	9.1	4 MVA to SBY22
SBY24	**2,3,4**	**14.3**	0.0	0.0	0.0	0.0	0.0	1.0	1.4	1.9	2.3	6 MVA to SBY35 11 MVA to SBY15
SBY31	**4**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM11
SBY32	**2,3,4**	**14.3**	10.2	11.0	11.6	12.0	12.5	12.9	13.4	13.8	14.2	5 MVA to SBY22
SBY35	**2,3,4**	**14.3**	12.5	12.5	12.5	12.6	12.7	12.9	13.1	13.2	13.4	6 MVA from SBY24
SHM11	**2,3**	**14.3**	0.8	3.1	4.7	5.5	6.2	6.8	7.3	7.7	8.1	7 MVA to SBY14
SHM11	**4**	**14.3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7 MVA to SBY14 10 MVA to SBY31
SHM13	**2**	**14.3**	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2 MVA from SHM14
SHM13	**3**	**14.3**	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4 MVA from SHM22
SHM13	**4**	**14.3**	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14 MVA from SHM14
SHM14	**2**	**14.3**	0.0	0.0	0.0	0.0	0.0	0.2	0.9	1.6	2.2	2 MVA to SHM13 10 MVA to PLN11 10 MVA to PLN12
SHM14	**3**	**14.3**	2.1	3.8	5.1	5.8	6.5	7.2	7.9	8.6	9.2	5 MVA to SHM32 10 MVA to SHM31
SHM14	**4**	**14.3**	3.1	4.8	6.1	6.8	7.5	8.2	8.9	9.6	10.2	14 MVA to SHM13
SHM22	**3**	**14.3**	2.1	2.2	2.3	2.4	2.6	2.8	3.0	3.2	3.4	4 MVA to SHM13
SHM31	**3**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM14
SHM32	**3**	**14.3**	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5 MVA from SHM14
PLN11	**2**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM14

Feeder	Option	New Rating	2026	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
PLN12	**2**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM14

Table 5-9 presents the 10% PoE winter 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 now. Assets not listed have the same forecast as Option 1 detailed in Table 2-9.

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

Feeder	Option	New Rating	2026	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
SBY13	**2,3,4**	**14.1**	4.5	4.9	5.2	5.4	5.8	6.0	6.3	6.5	6.8	3 MVA to SBY22
SBY14	**2,3,4**	**14.3**	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7 MVA from SHM11
SBY15	**2,3,4**	**14.3**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11 MVA from SBY24
SBY22	**2,3,4**	**14.3**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	3 MVA from SBY13 4 MVA from SBY32 4 MVA from SBY23
SBY23	**2,3,4**	**14.3**	6.6	7.1	7.5	7.9	8.4	8.8	9.1	9.5	9.8	4 MVA to SBY22
SBY24	**2,3,4**	**14.3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	6 MVA to SBY35 11 MVA to SBY15
SBY31	**4**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM11
SBY32	**2,3,4**	**14.3**	9.2	10.2	11.1	11.7	12.5	12.9	13.4	13.9	14.3	4 MVA to SBY22
SBY35	**2,3,4**	**14.3**	11.9	12.0	12.1	12.3	12.4	12.6	12.8	13.0	13.2	6 MVA from SBY24
SHM11	**2,3**	**14.3**	1.7	4.6	6.8	8.1	9.2	10.0	10.6	11.2	11.7	7 MVA to SBY14
SHM11	**4**	**14.3**	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.2	1.7	7 MVA to SBY14 10 MVA to SBY31
SHM13	**2**	**14.3**	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2 MVA from SHM14
SHM13	**3**	**14.3**	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4 MVA from SHM22
SHM13	**4**	**14.3**	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14 MVA from SHM14
SHM14	**2**	**14.3**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2 MVA to SHM13 10 MVA to PLN11 10 MVA to PLN12
SHM14	**3**	**14.3**	0.0	0.0	0.0	0.0	0.5	1.0	1.5	2.1	2.6	5 MVA to SHM32 10 MVA to SHM31

Feeder	Option	New Rating	2026	2027	2028	2029	2030	2031	2032	2033	2034	Transfers
SHM14	**4**	**14.3**	0.0	0.0	0.0	0.6	1.5	2.0	2.5	3.1	3.6	14 MVA to SHM13
SHM22	**3**	**14.3**	0.7	0.8	1.0	1.2	1.4	1.6	1.8	2.0	2.2	4 MVA to SHM13
SHM31	**3**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM14
SHM32	**3**	**14.3**	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5 MVA from SHM14
PLN11	**2**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM14
PLN12	**2**	**14.3**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10 MVA from SHM14

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 – Plumpton Plan

Table 5-10 details the zone substation and sub-transmission EUE for Option 2 over the planning horizon for the identified network limitations.

Table 5-10: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 2

Asset	SBY	SHM	PLN	KTS-SBY-SHM-GSB-WND	Total
2025	7.9	0.2	0.0	0.0	**8.0**
2026	9.2	0.3	0.0	0.0	**9.5**
2027	0.0	0.0	0.0	0.0	**0.0**
2028	0.0	0.0	0.0	0.0	**0.0**
2029	0.0	0.0	0.0	0.0	**0.0**
2030	0.0	0.0	0.0	0.0	**0.0**
2031	0.1	0.1	0.0	0.0	**0.2**
2032	0.3	0.4	0.0	0.0	**0.7**
2033	0.7	3.0	0.0	0.0	**3.7**
2034	1.3	23.1	0.0	0.1	**24.5**

Table 5-11 details the distribution feeder EUE for Option 2 over the planning horizon for the identified network limitations.

Table 5-11: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 2

Asset	SHM11	SHM14	SBY23	SBY24	ACR51070	ACR55612	sw51196	sw56781	Total
2025	15.4	0.6	3.3	0.0	55.5	0.0	0.0	0.0	**74.8**
2026	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	**0.9**
2027	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	0.3	0.0	0.0	2.5	1.0	**3.9**
2029	0.0	0.0	0.2	5.5	0.0	0.1	0.0	0.0	**5.8**
2030	0.0	0.0	1.2	22.3	0.0	0.0	0.0	0.0	**23.5**

5.4.2 Option 3 – Sydenham Plan

Table 5-12 details the zone substation and sub-transmission EUE for Option 3 over the planning horizon for the identified network limitations.

Table 5-12: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 3

Asset	SBY	SHM	KTS-SBY-SHM-GSB-WND	Total
2025	7.9	0.2	0.0	**8.0**
2026	9.2	0.3	0.0	**9.5**
2027	0.0	0.0	0.0	**0.0**
2028	0.0	0.0	0.0	**0.0**
2029	0.0	0.0	0.0	**0.0**
2030	0.0	0.0	0.0	**0.0**
2031	0.0	0.1	0.0	**0.1**
2032	0.0	0.4	0.0	**0.5**
2033	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.1	**0.1**

Table 5-13 details the distribution feeder EUE for Option 3 over the planning horizon for the identified network limitations.

Table 5-13: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 3

Asset	SHM11	SHM14	SBY23	SBY24	ACR51070	ACR55612	sw51196	sw56781	Total
2025	15.4	0.6	3.3	0.0	55.5	0.0	0.0	0.0	**74.8**
2026	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	**0.9**
2027	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	0.3	0.0	0.0	2.5	1.0	**3.9**
2029	0.0	0.0	0.2	5.5	0.0	0.1	0.0	0.0	**5.8**
2030	0.0	0.0	1.2	22.3	0.0	0.0	0.0	0.0	**23.5**

5.4.3 Option 4 – Sunbury Plan

Table 5-14 details the zone substation and sub-transmission EUE for Option 4 over the planning horizon for the identified network limitations.

Table 5-14: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 4

Asset	SBY	SHM	KTS-SBY-SHM-GSB-WND	Total
2025	7.9	0.2	0.0	**8.0**
2026	9.2	0.3	0.0	**9.5**
2027	0.0	0.0	0.0	**0.0**
2028	0.0	0.0	0.0	**0.0**
2029	0.0	0.0	0.0	**0.0**
2030	0.0	0.0	0.0	**0.0**
2031	0.1	0.1	0.0	**0.2**
2032	0.3	0.4	0.0	**0.7**
2033	0.7	3.0	0.0	**3.7**
2034	1.3	23.1	0.1	**24.5**

Table 5-15 details the distribution feeder EUE for Option 4 over the planning horizon for the identified network limitations.

Table 5-15: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 4

Asset	SHM11	SHM14	SBY23	SBY24	ACR51070	ACR55612	sw51196	sw56781	Total
2025	15.4	0.6	3.3	0.0	55.5	0.0	0.0	0.0	**74.8**
2026	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	**0.9**
2027	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	0.3	0.0	0.0	2.5	1.0	**3.9**
2029	0.0	0.0	0.2	5.5	0.0	0.1	0.0	0.0	**5.8**
2030	0.0	0.0	1.2	22.3	0.0	0.0	0.0	0.0	**23.5**

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 4 maximises the NPV, relative to all other options assessed.

Table 6-1: Summary of NPV Cost-Benefit Analysis ($M Real 2024)

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	0.0	6
Option 2 – Plumpton Plan	74.0	64.9	129	64.3	3
Option 3 - Sydenham Plan	52.0	50.9	140	88.9	2
Option 4 - Sunbury Plan	**36.8**	**40.8**	**139**	**98.1**	**1**
Option 5 – BESS Plan	**0**	**72.5**	**75**	**2.5**	**5**
Option 6 – DM Plan	**0**	**33.0**	**75**	**42.0**	**4**

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 ($M Real 2024)

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	0.0	0.0	0.0	0.0
Option 2 – Plumpton Plan	64.3	51.4	77.3	61.6	67.2	44.9	83.8	51.9
Option 3 - Sydenham Plan	88.9	74.9	102.9	84.3	93.0	73.6	104.2	77.4
Option 4 - Sunbury Plan	98.1	84.2	112.0	92.6	104.1	85.9	110.4	97.6

Option 4 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. Two deferrals were identified.

Table 6-3: Deferrals for Option 4 with no EV Charging at Peak Electricity Demand

Projects	Revised Timing	Years Deferred
Install Regulator - SBY13	2026	0
New feeder SHM-013	2026	0
New feeder SBY-022	2026	0
New feeder SBY-014	2026	0
New feeder SBY-015	2027	0
Upgrade SBY No.1 transformer to 20/33MVA Upgrade SBY No.3 transformer to 20/33MVA	2027	0
New feeder SBY-031	2027	0
Load transfer SBY24 to SBY35	2028	0

Augment steel section - SBY24	2029	0
Install Regulator - SBY23	2031	1

7. Recommendation and Next Steps

The assessment demonstrates that the preferred network development plan is to implement Option 4 (Sunbury Plan) because this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred Option 4 provides a 20-year present value net market benefit of $98.1 million for the base scenario, with a present value of $35.4 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 4) to address the identified network limitations include the following**:**

Table 7-1: Option 4 - Sunbury Plan

Timing	Projects	Cost (Real 2024)	Limitation Addressed
2026	Install Regulator - SBY13	[redacted]	SBY13 voltage limit (ex ACR51070)
2026	New feeder SHM-013	[redacted]	SHM14 overload
2026	New feeder SBY-022	[redacted]	SHM11 overload
2026	New feeder SBY-014	[redacted]	SBY23 overload
2027	New feeder SBY-015	[redacted]	SBY24 overload
2027	Upgrade SBY No.1 transformer to 20/33MVA	[redacted]	SBY overload
	Upgrade SBY No.3 transformer to 20/33MVA		SBY & SHM overload
2027	New feeder SBY-031	[redacted]	SHM overload
2028	Load transfer SBY24 to SBY35	[redacted]	SBY24 overload
2029	Augment steel section - SBY24	[redacted]	SBY24 sw56781 fuse rating
			SBY24 sw51196 fuse rating
2030	Install Regulator - SBY23	[redacted]	SBY23 voltage limit (ex ACR55612)
Total		**$36.8 million**	
Present Value Total		**$35.4 million**	

The estimated total capital cost of Option 4 for JEN over 10-years to address the identified network limitations is $36.8 million ($2024, Real), of which $5.8 million is outside the FY2027-31 regulatory control period. Table 7-2 lists the projects and their associated costs over the FY2027-31 regulatory control period.

Table 7-2: Option 4 - Sunbury, project within FY2027-31 regulatory control period

Timing	Projects	Cost (Real 2024)[28]	Limitation Addressed
2026	Install Regulator - SBY13	[redacted]	SBY13 voltage limit (ex ACR51070)
2026	New feeder SHM-013	[redacted]	SHM14 overload
2026	New feeder SBY-022	[redacted]	SHM11 overload
2026	New feeder SBY-014	[redacted]	SBY23 overload
2027	New feeder SBY-015	[redacted]	SBY24 overload
2027	Upgrade SBY No.1 transformer to 20/33MVA	[redacted]	SBY overload
	Upgrade SBY No.3 transformer to 20/33MVA		SBY & SHM overload
2027	New feeder SBY-031	[redacted]	SHM overload
2028	Load transfer SBY24 to SBY35	[redacted]	SBY24 overload
2029	Augment steel section - SBY24	[redacted]	SBY24 sw56781 fuse rating
			SBY24 sw51196 fuse rating
2030	Install Regulator - SBY23	[redacted]	SBY23 voltage limit (ex ACR55612)
Total		**$30.9 million**	

[28] Three projects with optimal timing of 2026 have cost incurred in FY2026, total of $5.8M, which is outside the FY2027-2031 regulatory control period.

8. Appendix A – High Level Scopes of Work

8.1 22 kV Feeders

8.1.1 New feeder SHM-013

The aim of this option is to offload part of SHM14 with a new feeder SHM13 rated at 375A.

This option involves constructing a new feeder, from the existing spare SHM13 feeder circuit breaker at SHM, along Victoria Road and Melton Hwy to just west of switch 50050 for 4.0 km using 22 kV 300mm^2 Al XLPE cable (two parallel conduits). Replace existing HV manual gas switch (50050) with a new Remote controlled Gas Switch along Melton Highway in normally open position.

Close 44125 and 57900. Open 50050, 14074 and 57844.

[redacted]

8.1.2 Reconfigure feeder SBY24

[redacted]

8.1.3 Install Regulator - SBY13

SBY13 currently supplies approximately 3,500 customers in north northwest supply area Sunbury zone substation. It extends up to the Powercor supply area boundary in Gisborne. The backbone section of the feeder is approximately 15 km long and the spurs are up to 7 km long. Most of the feeder backbone is made up of ACSR/AZ 6/1/3.0 7/1.60 conductor and almost all the rural spurs are 2-wires and made from 3/2.75 St (Sc Gz) conductor. Two present power quality issues are occurring in Gisborne South on SBY13, being

1. the voltage at Benson Rd-P11 and its surrounding substations are dropping in the order of 12 Volts for 1.5 hours every night around midnight; and
2. the supply voltage at Stanton Crt-P4 substation is going above 253V on a regular basis with the transformer set on its minimum voltage tap position, other transformers in the area will also be affected. The objective of the project is to return customers on SBY13 to voltage levels within the Victorian Electricity Distribution Code of Practice (EDCOP) regulatory limits.

[redacted]

This option involves installing a 3-phase 50A 32-step +/-10% voltage regulator on Couangalt Rd (west of corner of Blackhill Rd) and readjusting tap settings on transformers in the vicinity. The regulator shall be the same as that installed on COO12 at the Konagaderra Rd installation, and be equipped with LDC settings to boost voltage during maximum demand periods, and buck the voltage during minimum demand periods, in order to address the identified under and over-voltage limitations. Install two normally closed ACRs, one at switch 56716 and one at switch 50138. Install new 40A in-line fuses just north of 56716 (to protect the steel sections downstream). Open switch 55263.

8.1.4 Augment steel section - SBY24

This solution requires 12.0 km of steel sections of backbone on SBY24 in Lancefield Rd to be replaced with 19/3.25AAC between fused switch 51196 and Lancefield Rd Voltage Regulator, and south of fused switch 56781, replacing both fuses with MGS, and installing in-line fusing on unprotected steel spurs off these reconductored sections of backbone.

[redacted]

8.1.5 Install Regulator - SBY23

This option involves installing a 3-phase 50A 32-step +/-10% voltage regulator in Riddle Rd (just south of Settlement Rd) on SBY23 and readjusting tap settings on transformers in the vicinity. The regulator shall be the same as that installed on COO12 at the Konagaderra Rd installation, and be equipped with LDC settings to boost voltage during maximum demand periods, and buck the voltage during minimum demand periods.

[redacted]

8.1.6 New feeder SBY-022

The aim of this new feeder SBY22 is to offload SHM11. This option involves constructing a new feeder rated at 375 A, from the existing spare SBY22 feeder circuit breaker at SBY, along Vineyard Rd to just south of normally open switch 53069 for 0.7 km using 22 kV 300 mm^2 Al XLPE cable. Open 51635.

[redacted]

8.1.7 New feeder SBY-014

This option is designed to offload SBY13, SBY32 and SBY23 with a new 22 kV feeder from SBY. For the new feeder SBY22 rated at 375 A, install a 0.8 km 300mm^2 Al XLPE cable from the CHP on south side of 55452 (disconnecting the existing cable) up Anderson Rd to a new CHP just north of switch 54816. Install a 0.4 km 300mm^2 Al XLPE cable straight jointed to this disconnected cable back to the SVY22 CB at SBY. Install a new normally open switch in Elizabeth Dve between Gap Rd and Heysen Dve. Close 55794, 53069, 58473 and 51755. Open 50171, 59510, 57009 and 58670.

[redacted]

[redacted]

8.1.8 New feeder SBY-015

This option offloads SBY35 & SBY24 and involves establishing one new feeder at SBY. The rating of the new 22 kV feeder SBY15 shall be 375 A. Install a 1.0 km 300mm^2 Al XLPE cable down Shields St from SBY under the railway line to just north of normally open switch 55978. Install approximately 3000m of new HV overhead conductor (3 – 19/3.25) AAC from pole A005664, crossing the street along Macedon St and extending up to Lancefield Road up to Sunbury Road near A017688.

[redacted]

8.2 Plumpton Zone Substation

8.2.1 New 66/22 kV REFCL zone substation at PLN

Install a new single transformer 66/22 kV 20/33 MVA zone substation (designated PLN) at Plumpton with a base-performance 320A REFCL with an 8-ohm NER, and cut into the KTS-SBY No.2 66 kV line by establishing 3 km of new 66 kV line. Replace droppers at KTS on this line to increase the KTS-PLN line's emergency rating from 880 A to 1065 A.

[redacted]

8.2.2 New feeders PLN11 and PLN12

This option is required if a new zone substation is installed in Plumpton in order to utilise the capacity of the new transformer and alleviate loading levels on SHM feeders and its feeders.

[redacted]

It involves establishing three new feeders PLN11, PLN12, and PLN13 to supply the developing areas of Plumpton, Bonnie Brook and Fraser Rise, and tie into the SHM feeders SHM22, SHM13 and SHM14. The rating of the new 22 kV feeders shall be 375 A each.

8.3 Sydenham Zone Substation

8.3.1 3rd 66/22 kV transformer at SHM

Install a 3rd 66/22 kV 20/33 MVA transformer at SHM (No.3), a 3rd 22 kV switchboard in a new building with a new 66 kV line circuit breaker.

[redacted]

8.3.2 New feeders SHM31 and SHM32

This option is required if a 3^{rd} transformer is installed at SHM in order to utilise the capacity of the new transformer and alleviate loading levels on SHM feeders.

[redacted]

It involves establishing three new feeders from SHM from the new No.3 22 kV bus. The rating of the new 22 kV feeders SHM31, SHM32 and SHM33 shall be 375 A each. The new feeders to supply the developing areas of Plumpton, Bonnie Brook and Fraser Rise, and tie into the SHM feeders SHM22, SHM13 and SHM14. Swap SHM22 and SHM32 feeder exits to interleave the feeders.

8.4 Sunbury Zone Substation

8.4.1 Upgrade SBY No.1 transformer to 20/33MVA

This option involves replacing the existing 66/22 kV 10/16 MVA No.1 transformer at SBY with a 20/33 MVA transformer, and installing a second parallel incomer cable from the No.1 transformer to the No.1 22 kV bus.

[redacted]

8.4.2 Upgrade SBY No.3 transformer to 20/33MVA

This option involves replacing the existing 66/22 kV 10/16 MVA No.3 transformer at SBY with a 20/33 MVA transformer (following the replacement of the No.1 transformer in section 8.4.1), and installing a second parallel incomer cable from the No.3 transformer to the No.3 22 kV bus.

[redacted]

8.4.3 New feeder SBY-031

[redacted]

This option is required if both the No.1 and No.3 transformers at SBY are upgraded to 20/33 MVA in order to utilise the capacity of the replaced transformers and alleviate loading levels on SHM and its feeders. This option involves establishing one new feeder at SBY. The rating of the new 22 kV feeder SBY31 shall be 375 A. Install a 4.5 km 300mm^2 Al XLPE cable down Vineyard Rd from SBY to just south of switch 51635. The existing SHM11 feeder to be redirected and the SHM23 feeder to be extended to supply the developing areas (with SHM13 and SHM14) of Plumpton, Bonnie Brook and Fraser Rise. Open 43333, Close 63722.

8.4.4 REFCL upgrade at SHM

The existing 320A base performance REFCL to be replaced with a 400A REFCL as part of asset replacement project. This is a committed project due in 2025 and is common to all options.