Jemena Electricity Networks (Vic) Ltd

Major Customer Connections

Network Development Strategy

ELE-999-PA-EL-006

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Authorisation

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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.
Distributed Energy Resources (DER)	Solar PV, micro-generators, batteries (including electric vehicles), flexible load and other Embedded Generation connected within the distribution network.
Discount Rate	The nominated rate to be used in the economic evaluation discounting process (typically the WACC plus depreciation and operational cost percentage) to convert the value of a cost or benefit at some later point to time to its present value. The choice of Discount Rate depends on whether the analysis includes or excludes inflation.
Distribution Feeders	Radial 22 kV, 11 kV or 6.6 kV 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.
Terminal stations	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
ADT	Proposed Customer Zone Substation
ATS	Altona Terminal Station
AUH	Proposed Customer Zone Substation
AW	Airport West Zone Substation
BD	Broadmeadows Zone Substation
BESS	Battery Energy Storage System
BKN	Customer Zone Substation
BLTS	Brooklyn Terminal Station
BMS	Broadmeadows South Zone Substation
BTS	Brunswick Terminal Station
BY	Braybrook Zone Substation
CB	Circuit Breaker
CHP	Cable Head Pole
CN	Coburg North Zone Substation
COO	Coolaroo Zone Substation
CS	Coburg South Zone Substation
DBTS	Donnybrook Terminal Station (future)
DER	Distributed Energy Resources (includes Embedded Generation)
DM	Demand Management
(E)	Existing
EDCOP	Victorian Electricity Distribution Code of Practice
EP	East Preston Zone Substation
EPN	East Preston North Zone Substation
ES	Essendon Zone Substation
EUE	Expected Unserved Energy
EV	Electric Vehicle
(F)	Future
FE	Footscray East Zone Substation
FF	Fairfield Zone Substation
FT	Flemington Zone Substation
FW	Footscray West Zone Substation
HB	Heidelberg Zone Substation

HV	High Voltage
JEN	Jemena Electricity Network
KLO	Kalkallo Zone Substation
KTS	Keilor Terminal Station
kV	kilo-Volts
LTU	Proposed Customer Zone Substation
MAT	Customer Zone Substation
MB	Customer Zone Substation
MCFM	Major Customer Forecast Methodology
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
MDT	Proposed Customer Zone Substation
MDW	Proposed Customer Zone Substation
MSY	Proposed Customer Zone Substation
NDT	Proposed Customer Zone Substation
NDW	Proposed Customer Zone Substation
NDS	Network Development Strategy
NEI	Customer Zone Substation
NEL	Customer Zone Substation
NEM	National Electricity Market
NER	National Electricity Rules or Neutral Earthing Resistor (depending on context)
(N)	New
N/O	Normally Open
NH	North Heidelberg Zone Substation
NPV	Net Present Value
NS	North Essendon Zone Substation
NSP	Network Service Provider
NT	Newport Zone Substation
O&M	Operations and Maintenance
OH	Overhead Line
OLTC	On-Load Tap-Changer
OOS	Out of Service
PDW	Proposed Customer Zone Substation
PF	Power Factor
PoE	Probability of Exceedance

PTN	Preston Zone Substation
PV	Pascoe Vale Zone Substation (or Present Value or Photovoltaic)
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
SBY	Sunbury Zone Substation
SCI	Customer Zone Substation
SHM	Sydenham Zone Substation
SLD	Single Line Diagram
SMTS	South Morang Terminal Station
ST	Somerton Zone Substation
SYTS	Sydenham Terminal Station
TCPR	Transmission Connection Planning Report
TH	Tottenham Zone Substation
TMA	Tullamarine Zone Substation
TMTS	Tullamarine Terminal Station (future)
TSTS	Templestowe Terminal Station
TT	Thomastown Zone Substation
TTS	Thomastown Terminal Station
UG	Underground Cable
VCR	Value of Customer Reliability
VDT	Proposed Customer Zone Substation
WACC	Weighted Average Cost of Capital
WGT	Customer Zone Substation
WMTS	West Melbourne Terminal Station
WT	Watsonia Zone Substation
YTS	Yarraville Terminal Station (decommissioned)
YVE	Yarraville Zone Substation

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 major customer connections (including data centres) within the Jemena Electricity Network (**JEN**) service area. This NDS presents the current and emerging limitations within the service area over a 10-year planning horizon associated with connecting proposed major customer connections (including data centres) and articulates the need for augmentation and other capital works in order to address identified network needs.

This NDS considers likely requirements for planned staging (for both timing and maximum demand) of each data centre and major load connection, and any transitions needed from initial 22 kV supplies to ultimate 66 kV supplies. This includes an assessment and provision of a consolidated review of augmentation works on our distribution and sub-transmission network, with the view to optimising network capacity and cost-efficient solutions for uncommitted connections. The NDS considers network development synergies for accommodating multiple connections into the one area to minimise cost, taking into account a range of scenarios, each representing different likelihoods of each connection proceeding and reaching its ultimate state.

This NDS is supported by the Major Customer Forecast Methodology (**MCFM**)[1], which describes the method used by JEN for forecasting block load maximum demands, that are associated with increased demand for distribution services from prospective and existing major customers.

Identified Needs

We have received an unprecedented number of data centre and major load connection enquiries over the last two years.[2] Some of the enquiries are now proceeding to formal connection applications, offers and delivery phase.

Under the *National Electricity Rules* (**NER**), JEN is obligated to facilitate connections and associated connection works in good faith and using best endeavours. This is in line with good electricity industry practice.[3]

The need for an NDS specifically focussed on data centres and other major customer connections is that the demand requirements of these customers, have a material impact on our network development plans at all levels of our HV network and upstream[4].

Given the uncertainty that many of these uncommitted connections have in terms of their level of timing and load uptake, we have not included aggregated maximum demand as forecast by these customers. Instead, we have moderated forecast maximum demand into aggregated block load forecasts under three scenarios. This provides transparency into which network limitations are driven by underlying load growth (including electrification) and which are driven by major customer connections.

[1] Refer to ELE-999-PA-EL-007 Major Customer Forecast Methodology.

[2] Refer to Appendix C for further detail on the connection enquiries and applications.

[3] Chapter 5A of the NER and the Essential Services Commission Electricity Distribution Code of Practice.

[4] Note, this Network Development Strategy covers major customers and data centres. Other strategies cover our network on an area by area basis

Options Considered

This NDS presents a range of credible options to meet the forecast demand over a 10-year planning horizon, taking into account the uncertainty in those scenarios, whilst maintaining a safe and reliable supply to our customers within the service area. Several options to alleviate the emerging network limitations were investigated. These include:

- Option 1: **Do Nothing** (status quo);
- Option 2: **Base Development Plan** – in anticipation of a weighted demand forecast materialising;
- Option 3: **High Development Plan** – in anticipation of a higher demand forecast materialising;
- Option 4: **Low Development Plan** – in anticipation of a lower demand forecast materialising;
- Option 5: **On-Site Generation Plan;**
- Option 6: **Battery Energy Storage System (BESS) Plan**; and
- Option 7: **Demand Management (DM) Plan.**

Each option assumes the same maximum demand forecast that is weighted 50% to the base scenario, 25% to the low scenario, and 25% to the high maximum demand forecast scenario as detailed in our *Major Customer Forecast Methodology* document[5]. This weighted maximum demand forecast is used to quantify the 'do nothing' expected unserved energy risk, being the potential maximum reliability benefit available for each option.

Option 2, 3 and 4 all comprise a common set of solutions required regardless of which maximum demand forecast scenario (base, high or low) materialises. Options 2 and 3 include additional options (varying in scope and timing) with in turn lower levels of unserved energy. Option 1 assumes no additional network investment.

Option 5, 6 and 7 investigate the opportunity for using on-site generation, BESS and demand management as an alternative to augmentation.

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 of Upstream Network Limitations ($M Real 2024)

Option	Total Capital Cost	Present Value of Capital and O&M Cost	Present Value of Reliability Benefit	Net Present Value (NPV)	NPV Ranking
Option 1 - Do Nothing	0.0	0.0	0.0	0.0	6
Option 2 – Base Development Plan	51.6	54.2	473	418	2
Option 3 – High Development Plan	230.2	207.2	676	469	1
Option 4 – Low Development Plan	33.9	35.8	254	218	5
Option 6 – BESS Plan	0	352.9	676	323	3
Option 7 – DM Plan	0	427.5	676	249	4

5 ELE-999-PA-EL-007 Major Customer Forecast Methodology document.

Preferred Option

Economic analysis identifies that Option 3 (High Development Plan) maximises the net economic benefits with a net present value of $469 million. This is closely followed by Option 2 (Base Development Plan) with a net present value of $418 million.

In considering these options we note:

- We do not need to make a decision on whether to implement either option until around 2027, as both Option 2 and Option 3 are identical until 2028.
- The demand forecast, underpinning this strategy and the economic analysis, is based on a moderated view of the customer load requirements, for example a longer time to ramp-up and reach a lower level of maximum demand. Given that that the data-centre boom is just starting, we do not yet have a long-term time series of actual data to test and refine these assumptions.
- There is a material difference in augmentation requirements and capital expenditure between Option 2 ($51.6 million) and Option 3 ($230.2 million).

Given these factors, and the significant difference in capex, the preferred network development plan is to implement Option 2 (Base Development Plan), focusing on the no-regrets investments and continue monitoring the major customer and data centre connection pipeline as it is rapidly changing. We will regularly refresh our analysis with a view to identify whether we need to shift to Option 3 (High Development Plan).

Of the overall additional projects of Option 3 compared to Option 2 ($175.9 million), a number of these will be treated as contingent projects ($70.3 million).

A sensitivity analysis was also carried out to assess the effect of different inputs including capital costs, the discount rate and demand forecasts. Results showed that changing these variables may lead to a slight change in the optimal timing of some projects in the development plan. It does not change the ranking of options.

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 and plan for major customer connections (including data centres) within the **JEN** service area. This NDS presents the current and emerging limitations within the service area over a 10-year planning horizon associated with connecting proposed major customer connections, and articulates the need for augmentation and other capital works in order to address identified network needs.

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

1.2 Supply Area Overview

The area that is the subject of this NDS is the entire JEN service area, but specifically focussed on clusters of new major customer and data centre connections occurring in the Tullamarine, Footscray, Northern Growth Corridor and Heidelberg areas. Identified major customer and data centre connections are shown in Figure 1-2 in grey for those *uncommitted* sites included in our block load maximum demand forecast, and yellow for those *committed* sites in our underlying maximum demand forecast. Sites in blue are generation sites.

Figure 1-2 NDS Supply Area

[redacted]

1.3 Network Overview

1.3.1 Footscray Cluster

The zone substations and sub-transmission lines[6] contained within the Footscray cluster of the NDS supply area are shown schematically in Figure 1-3, along with the approximate locations of the major customer and data centre connection enquiries.

Figure 1-3 Footscray Cluster Zone Substations and Sub-transmission Lines

[redacted]

[6] 66 kV = blue; 22 kV = green; transmission = orange.

1.3.2 Tullamarine Cluster

The zone substations and sub-transmission lines[7] contained within the Tullamarine cluster of the NDS supply area are shown schematically in Figure 1-4, along with the approximate locations of the major customer and data centre connection enquiries.

Figure 1-4 Tullamarine Cluster Zone Substations and Sub-transmission Lines

[redacted]

[7] 66 kV = blue; 22 kV = green; transmission = yellow and orange.

1.3.3 Northern Growth Corridor Cluster

The zone substations and sub-transmission lines[8] contained within the Northern Growth Corridor cluster of the NDS supply area are shown schematically in Figure 1-5, along with the approximate locations of the major customer and data centre connection enquiries.

Figure 1-5 Northern Growth Corridor Cluster Zone Substations and Sub-transmission Lines

[redacted]

[8] 66 kV = blue; 22 kV = green; transmission = yellow and orange.

1.3.4 Heidelberg Cluster

The zone substations and sub-transmission lines[9] contained within the Heidelberg cluster of the NDS supply area are shown schematically in Figure 1-6, along with the approximate locations of the major customer and data centre connection enquiries.

Figure 1-6 Heidelberg Cluster Zone Substations and Sub-transmission Lines

[redacted]

[redacted]

[9] 66 kV = blue; 22 kV = green; transmission = yellow and orange.

2. Identified Need

The primary drivers for an asset management intervention in the NDS supply area is to:

- provide a connection point for prospective major customers and data centre connections; and
- address the current and emerging network utilisation limitations on the upstream network assets associated with supporting the initial and projected load of those customers.

Under the *National Electricity Rules* (**NER**), JEN is also obligated to facilitate connections and associated connection works in good faith and using best endeavours - in line with good electricity industry practice.[10]

2.1 Customer Block Load Forecasts

Our method for forecasting major customer and data centre block loads considers the customers' own forecast of their demand requirements, and our assessment of the likelihood and uptake of those forecasts.

We develop a known customer connection forecast based on customer forecasts of their load requirements moderated down. We apply three sets of moderations to develop three uptake scenarios (base, low and high).

The method we take to arrive at the moderated maximum demand forecasts of our customers' block loads, are detailed in our *Major Customer Forecast Methodology* document.[11] The load from these known customers is not included in our *underlying* network maximum demand forecasts.[12]

Table 2-1 shows the forecast summer[13] total block load across the JEN network, for the combined known and future major customer block loads in aggregate that are not included in our underlying maximum demand forecast, relative to 2023.

Table 2-1: Aggregated Moderated Customer Summer Block Load Forecast (MVA)[14]

Uptake Scenario	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Customer Raw Forecast	7	56	121	170	349	575	859	1187	1521	1935
Base Scenario	2	25	61	77	168	239	306	405	481	532
Low Scenario	2	21	50	62	122	192	242	296	325	368
High Scenario	7	36	75	112	200	298	453	607	712	810
Weighted Scenario[15]	**3**	**27**	**61**	**82**	**165**	**242**	**326**	**428**	**500**	**561**

[10] NER Chapter 5 & 5A.

[11] Refer to ELE-999-PA-EL-007 Major Customer Forecast Methodology.

[12] Our known customer connections forecast is tabulated in Appendix A of our *Major Customer Forecast Methodology.* The loads for our *underlying* network maximum demand forecasts are tabulated in Appendix B our *Major Customer Forecast Methodology*.

[13] Winter forecast maximum demand is 85% of the summer forecast, due to the reduced air-conditioning cooling requirements of major customers during the winter, particularly relevant for data centre and commercial loads.

[14] Based on customer information and forecast completed in August 2024.

[15] Weighted Maximum Demand Scenario has a 50% weighting on the Base Scenario, and 25% on each of the Low and High Scenarios.

2.2 Network Utilisation

Table 2-2 presents the upstream network assets whose utilisations are impacted by the connection of each major customer and data centre load. It also presents the connection works that are needed to establish a connection for the customer.

Table 2-2: Upstream Network Assets Impacted by each Customer Connection

Cluster	Customer Identifier	Stage	Connection Works	Upstream Zone Substation	Upstream Sub-transmission
Footscray Cluster	A154	All	New FT 11 kV Feeders	FT	WMTS-FT
	A997	All	FE 24 & YVE11 22 kV Feeders	FE	WMTS-FE-WGT-WMTS
	A54	All	TH 21 22 kV Feeder	TH	BLTS-BKN-TH-BLTS
	DC07	1	Existing BKN ZSS	BKN	BLTS-BKN-TH-BLTS
		2	Expand BKN ZSS	BKN	BLTS-BKN-TH-BLTS
	DC09	All	Establish and loop in PDW ZSS	-	BLTS-BKN-TH-BLTS
	DC19	1	Establish and loop in HDY ZSS	-	BLTS-BKN-TH-BLTS
		2	Expand HDY ZSS	-	BLTS-BKN-TH-BLTS
	DC02	1	TH 23 and FW 18 Feeder	TH	BLTS-BKN-TH-BLTS
		2	Establish and loop in NDF ZSS	-	BLTS-BKN-TH-BLTS
	DC26	All	Establish DC26 ZSS	-	BLTS-BKN-TH-BLTS
	DC30	All	Establish DC30 ZSS	-	BLTS-BKN-TH-BLTS
	DC32	All	Establish DC32 ZSS	-	BLTS-NT-YVE-BLTS
	A923	All	FW 12 & FE 25 22 kV Feeders	FW	BLTS-FW-BLTS
	DC06	All	Note [16]		
Tullamarine Cluster	A60	All	Expand MAT ZSS	MAT	KTS-TMA-MAT-KTS
	DC04	All	Establish MDT ZSS	-	KTS-TMA-MAT-KTS
	DC17	1	Establish ATK ZSS	-	KTS-SHM-SBY-KTS
		2	Expand ATK ZSS	-	KTS-SHM-SBY-KTS
	DC18	1	Establish and loop in ADT ZSS	-	KTS-TMA-MAT-KTS
		2	Expand ADT ZSS	-	KTS-TMA-MAT-KTS
	DC01	1	TMA 22 kV Feeder Existing NDT ZSS	TMA NDT	KTS-TMA-MAT-KTS
		2	Expand NDT ZSS	NDT	KTS-AW-NDT-PV-KTS
		3	Duplicate NDT ZSS	-	KTS-AW-NDT-PV-KTS
	DC12	1	Establish and loop in VDT ZSS	-	KTS-AW-NDT-PV-KTS
		2	Expand VDT ZSS	-	KTS-AW-NDT-PV-KTS
	DC10	1	Establish and loop in MDW	-	KTS-AW-NDT-PV-KTS
		2	Expand MDW	-	KTS-AW-NDT-PV-KTS
	TEMPB	All	New AW 22 kV Feeders	AW	KTS-AW-NDT-PV-KTS
	DC27	All	Establish DC27 ZSS	-	KTS-BY-ES-KTS
Northern Growth Corridor Cluster	A50	All	Existing ST 22 kV Feeder	ST	SMTS-ST-SSS-SMTS
	DC11	All	Establish DC11 ZSS	-	SMTS-ST-SSS-SMTS
	DC20	All	Establish DC20 ZSS	-	SMTS-ST-SSS-SMTS
	DC22	All	Establish DC22 ZSS	-	SMTS-ST-SSS-SMTS
	DC28	All	Establish DC28 ZSS	-	SMTS-ST-SSS-SMTS
	DC29	All	Establish DC29 ZSS	-	SMTS-ST-SSS-SMTS
	DC21	All	Establish DC21 ZSS	-	TTS-BD-BMS-COO-VCO-TTS
	DC24	All	Establish DC24 ZSS	-	TTS-BD-BMS-COO-VCO-TTS
	TEMPA	All	New BD 22 kV Feeders	BD	TTS-BD-BMS-COO-VCO-TTS
Heidelberg Cluster	A53 Site A	All	New EPN 22 kV Feeders	EPN	TTS-PTN-EPN-EP-TTS
	TEMP16	1	Augment EPN34 22 kV Feeder	EPN	TTS-PTN-EPN-EP-TTS
		2	Establish LTU ZSS	-	TTS-NEI-NH-WT-TTS

[16] Dedicated connection to the BLTS 22 kV terminal station.

	A53 Site B	All	Establish AUH ZSS	NH	TTS-NEI-NH-WT-TTS
	A197	All	Existing NEL ZSS and new feeders	NEL	TTS-NEI-NH-WT-TTS
	A17	All	New FF 6.6 kV Feeders	FF	BTS-FF-BTS
	A26	All	New FF 6.6 kV Feeders	FF	BTS-FF-BTS
	TEMP5	All	New FF 6.6 kV Feeders	FF	BTS-FF-BTS

To assess the impact on network utilisation for our upstream network assets supporting those major customer and data centre connections, we need to add our aggregated moderated block load maximum forecasts (as tabulated in Appendix C of our Major Customer Forecast Methodology document) to our underlying maximum demand forecasts for those affected assets. The impact of those forecasts on our upstream network asset utilisations are summarised below.

2.2.1 Network Ratings

This section details the network capacity ratings that are available to customers during system normal (**N**) conditions, single contingency (**N-1**) conditions with one network asset out of service (forced or planned outage), and for summer (worst case) and winter (best case) seasons. Table 2-3 present the ratings of zone substations servicing the supply area.

Table 2-3: Zone Substation Ratings (MVA)

Zone Substation	Summer (N)	Winter (N)	Summer (N-1)	Winter (N-1)
AW	130.0	130.0	100.5	102.0
BD	123.0	123.0	123.7	125.1
EPN [17]	66.0	66.0	38.0	38.0
FE	61.0	61.0	47.6	47.6
FF [18]	54.0	54.0	38.0	38.0
FT	60.0	60.0	34.8	34.8
FW	90.0	90.0	70.3	77.2
NH	93.0	93.0	75.2	76.0
ST	95.2	95.2	79.7	89.3
TH	90.0	90.0	47.6	47.6
TMA	66.0	66.0	38.0	39.6

Table 2-4 present the ratings of sub-transmission lines servicing the supply area.

Table 2-4: Sub-transmission Ratings (MVA)

Sub-transmission Network	Summer	Winter	Line Section
BLTS-FW-BLTS	86.3	86.3	BLTS-FW1
	65.7	86.3	BLTS-FW2
	65.7	**86.3**	**Overall (N-1)**

[17] Assumes a second 20/33 MVA transformer is installed at EPN and EP conversion is completed. Planned to be October 2025 and 2030.

[18] Assumes the No.3 transformer is replaced at FF. Planned to be completed by October 2026.

Sub-transmission Network	Summer	Winter	Line Section
	130.0	**170.0**	**Overall (N)**
BLTS-BKN-TH-BLTS	100.6	125.7	BLTS-BKN (BLTS-TH1)
	100.6	125.7	BLTS-TH (BLTS-TH2)
	100.6	**125.7**	**Overall (N-1)**
	150.0	**160.0**	**Overall (N)**
BTS-FF-BTS[19]	11.4	13.0	BTS-FF181
	13.1	13.7	BTS-FF188
	13.1	13.7	BTS-FF184
	24.5	**26.7**	**Overall (N-1)**
	37.6	**40.4**	**Overall (N)**
KTS-AW-NDT-PV-KTS	117.0	126.0	KTS-AW (KTS-AW1)
	117.0	126.0	KTS-NDT (KTS-AW2)
	100.6	105.7	KTS-PV
	166.0	**182.0**	**Overall (N-1)**
	266.0	**291.0**	**Overall (N)**
KTS-TMA-MAT-KTS	101.7	105.7	KTS-TMA
	97.1	114.0	KTS-MAT
	97.1	**105.7**	**Overall (N-1)**
	160.0	**170.0**	**Overall (N)**
SMTS-ST-SSS-SMTS	117.2	121.7	SMTS-SSS
	117.2	126.3	SMTS-ST
	117.2	**126.3**	**Overall (N-1)**
	190.0	**200.0**	**Overall (N)**
TTS-BD-BMS-COO-VCO-TTS	101.7	104.6	TTS-BMS
	117.2	126.3	TTS-BD
	101.7	112.6	TTS-COO
	196.0	**217.0**	**Overall (N-1)**
	293.0	**324.0**	**Overall (N)**
TTS-NEI-NH-WT-TTS	117.2	126.3	TTS-NH
	117.2	126.3	TTS-WT
	117.2	**126.3**	**Overall (N-1)**
	180.0	**190.0**	**Overall (N)**
TTS-PTN-EPN-EP-TTS	81.2	107.5	TTS-PTN
	78.9	93.2	TTS-EP
	78.9	**93.2**	**Overall (N-1)**
	140.0	**170.0**	**Overall (N)**
WMTS-FE-WGT-WMTS	84.6	91.5	WMTS-FE1
	83.5	91.5	WMTS-FE2
	83.5	**91.5**	Overall (N-1)

[19] Assumes the augmentation of the BTS-FF 22 kV sub-transmission loop is completed by October 2026.

Sub-transmission Network	Summer	Winter	Line Section
	160.0	**175.0**	Overall (N)
WMTS-FT	52.0	64.0	WMTS-FW1
	65.2	76.6	WMTS-FT2
	52.0	**64.0**	**Overall (N-1)**
	101.0	**120.0**	**Overall (N)**

2.2.2 Historical Maximum Demand

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

Network Asset	N Rating	N-1 Rating	2020	2021	2022	2023	2024
AW	**130.0**	**100.5**	70.9	66.5	67.3	69.8	71.4
BD	**123.0**	**123.7**	72.4	64.0	68.0	70.5	71.2
EPN	**33.0**	**0.0**	20.6	9.9	10.8	11.0	25.4
FE	**61.0**	**47.6**	32.0	26.6	26.8	18.7	31.1
FF	**36.0**	**21.9**	24.2	20.9	21.8	23.3	24.1
FT	**60.0**	**34.8**	37.6	32.3	32.3	34.1	37.9
FW	**90.0**	**70.3**	44.6	39.0	37.2	37.3	42.1
NH	**93.0**	**75.2**	65.6	57.9	58.6	60.6	50.8
ST	**95.2**	**79.7**	76.4	65.6	71.1	70.4	71.9
TH	**90.0**	**47.6**	26.4	26.6	28.1	26.2	20.8
TMA	**66.0**	**38.0**	20.6	22.0	24.9	24.8	25.2
BLTS-FW-BLTS	**130.0**	**65.7**	44.6	39.0	37.2	37.3	42.1
BLTS-BKN-TH-BLTS	**150.0**	**100.6**	26.4	26.6	28.1	26.2	20.8
BTS-FF-BTS	**37.6**	**24.5**	24.2	20.9	21.8	23.3	24.1
KTS-AW-NDT-PV-KTS	**266.0**	**166.0**	112.7	100.3	103.3	108.6	108.6
KTS-TMA-MAT-KTS	**160.0**	**97.1**	49.7	42.4	49.5	51.3	51.7

Network Asset	N Rating	N-1 Rating	2020	2021	2022	2023	2024
SMTS-ST-SSS-SMTS	**190.0**	**117.2**	76.4	65.6	71.1	70.4	71.9
TTS-BD-BMS-COO-VCO-TTS	**293.0**	**196.0**	169.6	156.8	169.1	166.5	167.2
TTS-NEI-NH-WT-TTS	**180.0**	**117.2**	125.0	131.3	127.5	115.8	116.8
TTS-PTN-EPN-EP-TTS	**140.0**	**78.9**	48.4	54.4	59.1	60.3	74.7
WMTS-FE-WGT-WMTS	**160.0**	**83.5**	32.0	26.6	26.8	18.7	31.1
WMTS-FT	**101.0**	**52.0**	37.6	32.3	32.3	34.1	37.9

Table 2-6 presents the historical actual winter 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.

Table 2-6: Actual Historical Winter Maximum Demand (MVA)

Network Asset	N Rating	N-1 Rating	2020	2021	2022	2023
AW	**130.0**	**102.0**	58.9	53.9	56.8	63.6
BD	**123.0**	**125.1**	65.4	66.5	69.7	77.4
EPN	**33.0**	**0.0**	8.5	7.7	8.2	20.3
FE	**61.0**	**47.6**	30.3	30.5	18.3	26.2
FF	**36.0**	**21.9**	20.8	20.1	21.0	23.6
FT	**60.0**	**34.8**	29.3	32.2	31.3	37.6
FW	**90.0**	**77.2**	39.0	38.1	38.0	42.3
NH	**93.0**	**76.0**	49.7	49.1	51.7	47.0
ST	**95.2**	**89.3**	69.7	73.1	75.4	83.8
TH	**90.0**	**47.6**	26.4	27.9	29.0	32.4
TMA	**66.0**	**39.6**	16.7	23.1	24.5	27.3
BLTS-FW-BLTS	**170.0**	**86.3**	39.0	38.1	38.0	42.3
BLTS-BKN-TH-BLTS	**160.0**	**125.7**	26.4	27.9	29.0	32.4
BTS-FF-BTS	**40.4**	**26.7**	20.8	20.1	21.0	23.6

Network Asset	N Rating	N-1 Rating	2020	2021	2022	2023
KTS-AW-NDT-PV-KTS	**291.0**	**182.0**	90.4	84.6	87.7	94.8
KTS-TMA-MAT-KTS	**170.0**	**105.7**	33.8	42.5	48.2	51.3
SMTS-ST-SSS-SMTS	**200.0**	**126.3**	69.7	73.1	75.4	83.8
TTS-BD-BMS-COO-VCO-TTS	**324.0**	**217.0**	152.2	156.3	162.1	171.3
TTS-NEI-NH-WT-TTS	**190.0**	**126.3**	95.0	98.0	97.3	96.0
TTS-PTN-EPN-EP-TTS	**170.0**	**93.2**	50.2	52.5	49.3	62.2
WMTS-FE-WGT-WMTS	**175.0**	**91.5**	30.3	30.5	18.3	26.2
WMTS-FT	**120.0**	**64.0**	29.3	32.2	31.3	37.6

2.2.3 Maximum Demand Forecast

This section presents the maximum demand forecast over the next 10-years for the NDS supply area, considering the major customer and data centre new block loads for the weighted scenario, underlying growth and the impacts of Distributed Energy Resources (**DER**). The maximum demand forecasts are developed under different ambient temperature conditions, designated by a Probability of Exceedance (**PoE**).

Table 2-7 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.

Table 2-7: 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
AW	**130.0**	**100.5**	75.0	76.8	79.0	80.9	80.9	82.1	83.5	84.9	86.3	87.3
BD	**123.0**	**123.7**	75.4	78.7	81.7	83.7	84.3	85.4	86.7	88.0	89.3	90.2
EPN	**66.0**	**38.0**	29.3	30.3	38.0	43.3	46.8	50.5	51.2	52.0	52.6	53.1
FE	**61.0**	**47.6**	40.8	41.0	41.5	42.5	43.5	44.8	46.2	47.7	49.2	50.5

Network Asset	N Rating	N-1 Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF	**54.0**	**38.0**	26.1	26.8	29.2	31.5	33.1	34.5	35.4	36.4	37.2	37.9
FT	**60.0**	**34.8**	42.0	44.2	47.0	49.4	51.3	52.6	54.1	55.7	57.2	58.6
FW	**90.0**	**70.3**	46.1	53.5	55.3	56.4	58.9	58.9	59.0	59.2	59.3	59.2
NH	**93.0**	**75.2**	54.8	50.5	51.6	52.4	52.7	53.6	54.5	55.5	56.5	57.2
ST	**95.2**	**79.7**	80.7	85.3	90.6	95.0	**98.2**	**100.6**	**103.3**	**106.0**	**108.7**	**111.1**
TH	**90.0**	**47.6**	21.8	19.4	21.5	22.3	23.0	22.3	22.4	22.5	22.6	22.6
TMA	**66.0**	**38.0**	22.5	22.6	22.8	22.3	22.6	23.0	23.5	23.9	24.3	24.7
BLTS-FW-BLTS	**130.0**	**65.7**	46.1	53.5	55.3	56.4	58.9	58.9	59.0	59.2	59.3	59.2
BLTS-BKN-TH-BLTS	**150.0**	**100.6**	38.7	42.9	46.2	50.7	54.8	59.8	64.5	72.2	82.4	92.5
BTS-FF-BTS	**37.6**	**24.5**	26.8	27.6	30.2	32.7	34.7	36.1	37.2	**38.2**	**39.2**	**40.0**
KTS-AW-NDT-PV-KTS	**266.0**	**166.0**	121.0	125.4	132.8	142.8	149.5	157.7	168.2	179.3	188.9	198.1
KTS-TMA-MAT-KTS	**160.0**	**97.1**	48.0	66.5	74.8	83.9	102.4	126.0	151.9	**168.7**	**177.3**	**185.8**
SMTS-ST-SSS-SMTS	**190.0**	**117.2**	80.7	86.8	95.3	102.1	107.9	115.0	123.0	130.4	136.2	141.6
TTS-BD-BMS-COO-VCO-TTS	**293.0**	**196.0**	185.0	189.6	194.0	197.1	198.6	201.4	204.8	208.2	211.5	214.1
TTS-NEI-NH-WT-TTS	**180.0**	**117.2**	130.7	132.4	136.4	139.1	140.4	145.7	161.7	163.5	167.0	170.3
TTS-PTN-EPN-EP-TTS	**140.0**	**78.9**	77.0	83.8	85.5	87.8	88.8	90.1	93.4	94.8	96.2	97.2
WMTS-FE-WGT-WMTS	**160.0**	**83.5**	47.8	48.0	48.5	49.5	50.5	51.8	53.2	54.7	56.2	57.5

Network Asset	N Rating	N-1 Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
WMTS-FT	**101.0**	**52.0**	42.0	44.2	47.0	49.4	51.3	52.6	54.1	55.7	57.2	58.6

Assuming EPN (within the North Heidelberg Cluster) has its additional transformer installed, the EP conversion is completed, and the FF No.3 transformer is replaced, there remains ST, BTS-FF-BTS and KTS-TMA-MAT-KTS that have 10% PoE summer forecasts exceeding their N rating within the next 10-years. These and EPN, FE, FT, BTS-FF-BTS, KTS-AW-NDT-PV-KTS, SMTS-ST-SSS-SMTS, TTS-BD-BMS-COO-VCO-TTS, TTS-NEI-NH-WT-TTS, TTS-PTN-EPN-EP-TTS and WMTS-FT, are also forecast to have load at risk under N-1 conditions during summer.

Table 2-8 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.

Table 2-8: 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
AW	**130.0**	**102.0**	58.3	61.4	64.5	66.9	67.9	69.1	70.2	71.3	72.4	73.5
BD	**123.0**	**125.1**	78.4	83.1	87.1	89.6	90.6	91.7	92.8	93.8	94.8	95.9
EPN	**66.0**	**38.0**	26.2	27.8	36.0	41.6	45.5	51.0	51.7	52.4	53.1	53.8
FE	**61.0**	**47.6**	40.2	41.2	42.3	43.7	45.1	46.5	47.2	48.6	50.0	51.4
FF	**54.0**	**38.0**	23.0	24.4	27.2	30.0	31.8	33.4	34.4	35.5	36.3	37.2
FT	**60.0**	**34.8**	38.8	41.7	45.4	48.3	51.0	53.3	55.1	56.8	58.5	**60.1**
FW	**90.0**	**77.2**	43.1	51.5	54.2	56.0	59.1	59.5	59.7	59.9	60.0	60.1
NH	**93.0**	**76.0**	44.7	41.7	43.6	44.7	45.5	46.5	47.4	48.3	49.1	50.0
ST	**95.2**	**89.3**	82.0	87.9	93.9	**98.7**	**102.3**	**104.8**	**107.0**	**109.2**	**111.5**	**113.8**
TH	**90.0**	**47.6**	31.3	29.5	31.7	33.4	33.4	33.5	33.6	33.6	33.7	33.7
TMA	**66.0**	**39.6**	22.5	23.0	23.4	23.9	24.3	24.7	25.0	25.4	25.7	26.1
BLTS-FW-BLTS	**170.0**	**86.3**	43.1	51.5	54.2	56.0	59.1	59.5	59.7	59.9	60.0	60.1
BLTS-BKN-TH-BLTS	**160.0**	**125.7**	45.6	49.4	52.7	57.5	60.5	65.4	69.4	75.9	84.5	93.1

Network Asset	N Rating	N-1 Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
BTS-FF-BTS	**40.4**	**26.7**	23.3	24.7	27.8	30.7	33.0	34.8	35.9	37.1	38.1	39.2
KTS-AW-NDT-PV-KTS	**291.0**	**182.0**	95.6	101.9	110.2	120.1	127.3	134.9	143.8	153.6	161.9	170.2
KTS-TMA-MAT-KTS	**170.0**	**105.7**	49.6	66.2	73.8	82.5	98.3	118.1	139.9	153.9	160.9	167.9
SMTS-ST-SSS-SMTS	**200.0**	**126.3**	82.0	89.1	97.9	104.8	110.6	117.1	123.8	130.0	134.8	139.7
TTS-BD-BMS-COO-VCO-TTS	**324.0**	**217.0**	177.4	185.2	191.6	195.6	197.9	200.4	202.6	204.5	206.9	209.3
TTS-NEI-NH-WT-TTS	**190.0**	**126.3**	103.6	106.3	111.4	114.5	116.6	121.6	135.8	137.7	141.1	144.7
TTS-PTN-EPN-EP-TTS	**170.0**	**93.2**	69.1	77.2	80.2	83.0	84.8	86.5	89.5	90.8	92.1	93.3
WMTS-FE-WGT-WMTS	**175.0**	**91.5**	47.2	48.2	49.3	50.7	52.1	53.5	54.2	55.6	57.0	58.4
WMTS-FT	**120.0**	**64.0**	38.8	41.7	45.4	48.3	51.0	53.3	55.1	56.8	58.5	60.1

Assuming EPN has its additional transformer installed, the EP conversion is completed, and the FF No.3 transformer is replaced, there remains ST and FT that have 10% PoE forecasts exceeding their N rating within the next 10-years. These and EPN, FE, BTS-FF-BTS, KTS-TMA-MAT-KTS, SMTS-ST-SSS-SMTS, TTS-NEI-NH-WT-TTS, and TTS-PTN-EPN-EP-TTS, are also forecast to have load at risk under N-1 conditions during winter.

2.3 Summary of Network Limitations

This NDS assesses the technical and economic viability of solutions to alleviate the network connection and network asset utilisation issues identified above. A summary of credible solutions is presented in Table 2-9 that address the identified limitations. Further details and diagrams of the scope of the solutions is provided in the Appendices.

Table 2-9: Summary of identified network limitations under weighted demand scenario and possible solutions

Network Asset	Limitation	From	Credible network solutions to address the need[20]
ST	(N) Overload (N-1) Overload	2028 Existing	Adopt plan detailed in Northern Growth Corridor NDS.
EPN	(N) Overload (N-1) Overload	2027 2027	Proceed with committed second transformer at EPN and EP 6.6 kV to 22 kV conversion (RIT-D completed). Load transfers from EPN to NH.[21] EPN Third Transformer. New Zone Substation to offload NH and EPN. <u>BESS and/or demand management in EPN 22 kV distribution network</u>
FF	(N-1) Overload (N-1) Overload	Existing 2035	Proceed with committed FF No.3 transformer replacement (RIT-D completed). FF #4 6.6 kV Bus. Fourth transformer at FF. FF Conversion. <u>BESS and/or demand management in FF 6.6 kV distribution network</u>
FT	(N) Overload (N-1) Overload	2032 Existing	Adopt plan detailed in 11 kV Central Area NDS.
FE	(N-1) Overload	2032	Load transfers to FW. <u>BESS and/or demand management in FE 22 kV distribution network</u>
BLTS-BKN-TH-BLTS	(N-1) Overload	2035	Tie TH-FW 66kV line. First new 66 kV circuit from BLTS. Second new 66 kV circuit from BLTS. <u>BESS and/or demand management in 22 kV and 11 kV distribution networks ex BLTS-BKN-TH-BLTS</u>
TTS-NEI-NH-WT-TTS	(N-1) Overload	Existing	Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop. Third line into TTS-NEI-NH-WT-TTS. <u>BESS and/or demand management in NH, WT and NEL 22 kV distribution networks</u>
TTS-PTN-EPN-EP-TTS	(N-1) Overload	2026	Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop. <u>BESS and/or demand management in PTN and EPN 22 kV distribution networks</u>

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

[21] Post Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop.

Network Asset	Limitation	From	Credible network solutions to address the need20
KTS-TMA-MAT-KTS	(N) Overload (N-1) Overload	2032 2029	Reconfigure existing KTS-TMA to be KTS-MAT-MDT 66 kV line Augment KTS-AW 66 kV line. New KTS-TMA 66 kV line. New KTS-ADT-VDT 66 kV line. TMTS New Sub-Transmission Loop. SYTS New Sub-Transmission Loop. BESS and/or demand management in distribution networks ex KTS-TMA-MAT-KTS
BTS-FF-BTS	(N) Overload (N-1) Overload	2032 2025	Proceed with committed upgrade of BTS-FF-BTS (RIT-D completed). Reconductor BTS-FF 181. BESS and/or demand management in FF 6.6 kV distribution network
KTS-AW-NDT-PV-KTS	(N-1) Overload	2031	Augment KTS-AW 66 kV line. New KTS-ADT-VDT 66 kV line. New KTS-NDT2.5 66 kV line. TMTS New Sub-Transmission Loop. SYTS New Sub-Transmission Loop. BESS and/or demand management in distribution networks ex KTS-AW-NDT-PV-KTS
TTS-BD-BMS-COO-VCO-TTS	(N-1) Overload	2028	TTS New Sub-Transmission Loop. BESS and/or demand management in distribution networks ex TTS-BD-BMS-COO-VCO-TTS
WMTS-FT	(N-1) Overload	2030	Adopt plan detailed in 11 kV Central Area NDS.
SMTS-ST-SSS-SMTS	(N-1) Overload	2031	ST-SSS 66 kV Line Extension. SMTS New Sub-Transmission Loop. TMTS New Sub-Transmission Loop. DBTS New Sub-Transmission Loop. BESS and/or demand management in distribution networks ex SMTS-ST-SSS-SMTS

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

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.

The credible network solutions to address the needs in Table 2-9 only relate to upstream JEN network limitations whose scopes of work are detailed in . [22] They do not include the works needed to connect each major customer as summarised in Table 2-2, nor the works needed at the transmission connection level. The customer connections scopes of work are detailed in and the transmission connection scopes of work are detailed in Appendix E.[23]

22 See Appendix B – Scopes of Work for Upstream Augmentations.

23 See Appendix E – Scopes of Work for Terminal Stations.

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 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), The intention of which is to, defer or reduce in scope, traditional network augmentation solutions undertaken by distribution networks. Such solutions need to consider the secure redundancy requirements demanded by major customers and data centres, to provide the aggregate level of dispatchable capacity needed, to defer an augmentation by at least one year. This could then address identified capacity limitations, and avoid supply interruptions or asset overload damage which may otherwise occur without adequate network support.

Demand management solutions are targeted at reducing the peak demand by reducing customer load. This includes direct load control, and for our major customers and data centres , also includes operating environment temperature control, and production process control. 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, long duration storage and standby diesel or gas turbine 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 an identified need. The criteria we use to assess the potential credibility of non-network or SAPS solutions for our major customers and data centres 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.
- **Meeting the customer need**: being able maintain the level of redundancy required to meet the customers' need for security of supply.

Our market scan of data centre connections in the JEN service area has revealed that essentially all of them will have on-site generation for the sole purpose of providing an overall N-2 level of backup for their site, rather than as a substitute to the N-1 redundancy (which was requested by all data centre connections) for the network connection. Therefore there is little to no opportunity to maintain an N-2 level of redundancy using additional generation on site in-lieu of a network connections, given the high operating costs of fuel and the common mode failure risk that it introduces for our customers.

Alternatively, for BESS or demand response solutions, at least 342 MW of network support would be needed by the end of the 10-year planning horizon with 2 hours of storage[24].

24 BESS installed cost of $500/kWh x $676 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $353 million (present value). Demand response dispatch cost of $30/kWh x $676 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $21.2 million pa plus 0.2 million pa in fixed ongoing costs (present value).

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 cost of EUE for all the solutions analysed in this document:

- All options utilise the same maximum demand forecast, being a Weighted maximum demand growth Scenario, comprising of a 50% weighting on the Base maximum demand growth Scenario, and 25% on each of the Low and High maximum demand growth Scenarios;
- 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%;
- O&M costs of 1% of capital cost per annum;
- Economic analysis period for cost-benefit analysis set at 20 years;
- Zone substation and sub-transmission EUE based on 10-year demand forecast, held constant thereafter;
- 70% weighting on 50% PoE, and 30% weighting on 10% PoE for calculation of the EUE; and
- Locational Values of Customer Reliability (VCR) as per Table 3-1 below (Real, 2024).

Table 3-1: Locational Values of Customer Reliability

Zone Substation	VCR ($/MWh)	Sub-transmission Loop	VCR ($/MWh)
AW	46,286	BLTS-FW-BLTS	44,902
BD	50,963	BLTS-BKN-TH-BLTS	58,759
EPN	48,941	BTS-FF-BTS	37,440
FE	42,065	KTS-AW-NDT-PV-KTS	46,286
FF	37,440	KTS-TMA-MAT-KTS	53,201
FT	48,818	SMTS-ST-SSS-SMTS	52,502
FW	44,902	TTS-BD-BMS-COO-VCO-TTS	50,963
NH	47,110	TTS-NEI-NH-WT-TTS	47,110
ST	52,502	TTS-PTN-EPN-EP-TTS	42,469
TH	58,759	WMTS-FE-WGT-WMTS	42,065
TMA	53,201	WMTS-FT	48,818

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 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

BLTS-BKN-TH-BLTS	KTS-TMA-MAT-KTS	KTS-AW-NDT-PV-KTS	TTS-BD-BMS-COO-VCO-TTS	SMTS-ST-SSS-SMTS	TTS-NEI-NH-WT-TTS	TTS-PTN-EPN-EP-TTS	NH & EPN	BTS-FF-BTS	FF	Total
0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	8.8	0.0	**8.8**
0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	13.5	0.0	**13.5**
0.0	0.0	0.0	0.0	0.0	440.0	0.0	0.0	38.0	0.0	**38.0**
0.0	76.2	0.0	0.0	0.0	337.1	0.0	0.9	84.0	0.0	**161.1**
0.0	1,500	0.0	0.0	0.0	722.5	0.0	8.1	156.7	0.0	**1,665**
39.4	1,500	0.0	0.0	0.0	1,394	0.0	29	256.1	0.0	**1,825**
350.0	1,507	0.0	0.0	0.0	1,500	0.0	33.1	368.2	0.0	**2,258**

1,500	1,528	0.0	0.0	0.4	1,500	0.1	37.3	541.2	0.0	**3,607**
1,500	1,559	60.9	0.0	49.9	1,500	0.1	41.5	831.2	0.0	**4,042**
1,500	1,616	492	0.0	337.7	1,500	0.1	45.6	1,238.6	0.0	**5,230**[25]

To moderate the EUE, the do nothing option EUE relating to the inability to connect customers to a particular network asset is capped to its prior year value when it starts to exceed 1,500 MWh pa. The component of the EUE that relates to upstream limitations once a customer is connected, remains uncapped.

[25] Under the base case option, there is forecast of 5.2 GWh of unserved energy which has a consumer cost of $263 million by 2034 and this value grows over time.

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

Table 4-2 details the zone substation and sub-transmission EUE for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-2: Zone Substation and Sub-transmission Value of Expected Unserved Energy ($k, Real 2024) – Option 1

Asset	BLTS-BKN-TH-BLTS	KTS-TMA-MAT-KTS	KTS-AW-NDT-PV-KTS	TTS-BD-BMS-COO-VCO-TTS	SMTS-ST-SSS-SMTS	TTS-NEI-NH-WT-TTS	TTS-PTN-EPN-EP-TTS	NH & EPN	BTS-FF-BTS	FF	Total
2025	0	0	0	0	0	7	0	0	330	0	**330**
2026	0	0	0	0	0	13	0	0	507	0	**507**
2027	0	0	0	0	0	20,985	0	0	1,424	0	**1,424**
2028	0	4,012	0	0	0	16,078	0	47	3,145	0	**7,243**
2029	0	79,024	0	0	0	34,458	1	410	5,866	0	**86,065**
2030	2,289	79,045	0	0	0	66,480	1	1,477	9,589	0	**93,158**
2031	20,336	79,382	0	0	0	71,538	2	1,674	13,784	0	**116,137**
2032	87,150	80,476	0	0	21	71,538	3	1,884	20,262	0	**191,517**
2033	87,150	82,117	2,768	0	2,582	71,538	4	2,096	31,122	0	**209,656**
2034	87,150	85,138	22,353	1	17,477	71,538	5	2,306	46,372	0	**263,214**

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 to address the identified needs.	Nil
Option 2 Base Development Plan	This is the augmentation plan required to securely supply prospective major customers and data centres based on our expected view of their likelihood, load uptake and timing.	This option provides a prudent development path if the actual maximum demand is comparable to the weighted maximum demand growth scenario used in this NDS. It aims to address at least 50% of the EUE risk.
Option 3 High Development Plan	This is the augmentation plan required to securely supply prospective major customers and data centres based on a more optimistic long-term view of their likelihood, load uptake and timing.	This option provides a prudent development path if the actual maximum demand is materially higher than the weighted maximum demand growth scenario used in this NDS. It aims to address 100% of the EUE risk.
Option 4 Low Development Plan	This is the augmentation plan required to securely supply prospective major customers and data centres based on a more pessimistic long-term view of their likelihood, load uptake and timing.	This option provides a prudent development path if the actual maximum demand is materially lower than the weighted maximum demand growth scenario used in this NDS. It aims to address up to 50% of the EUE risk.
Option 5 On-Site Generation Plan	This option investigates the opportunity for using on-site generation as an alternative to augmentation, required to securely supply our prospective major customers and data centres.	Our market scan of our data centre connections has revealed that essentially all of them will have on-site generation for the sole purpose of providing an overall N-2 level of backup for their site, rather than as a substitute to the N-1 redundancy (that they all requested) for the network connection. Therefore there is virtually no opportunity to maintain an N-2 level of redundancy using additional generation on site in-lieu of one of the network connections, given the high operating costs of fuel and the common mode failure risk that it introduces for our customers.

Option 6 BESS Plan	342 MW / 600 MWh BESS ramp up over 10 years, distributed across major customer sites and JEN distribution networks in major customer affected areas.	Location and timing of BESS to align with major customer load uptake to support the affected sub-transmission line and zone substation limitations. BESS can be located at the major customer sites, or within the JEN distribution network whose upstream assets are shared by those major customers.
Option 7 DM Plan	342 MW / 600 MWh DM ramp up over 10 years, distributed across major customer sites and JEN distribution networks in major customer affected areas.	Location and timing of DM to align with major customer load uptake to support the affected sub-transmission line and zone substation limitations. DM can be adopted at the major customer sites, or within the JEN distribution network whose upstream assets are shared by those major customers.

All options utilise the same maximum demand forecast, being a Weighted maximum demand growth Scenario, comprising of a 50% weighting on the Base maximum demand growth Scenario, and 25% on each of the Low and High maximum demand growth Scenarios.

Some projects within these options are common across all options. Such projects are considered by us to be no-regrets investments, where the projects needs are relatively insensitive to changes in individual major customer or data centre connection and load uptake requirements.

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
Base</th><th>Option 3
High</th><th>Option 4
Low</th></tr>
<tr><td rowspan="3">(Footscray Cluster)
BLTS-BKN-TH-BLTS</td><td rowspan="5">Nil.</td><td colspan="2">9.1.1 Tie TH-FW 66kV line</td><td>Nil</td></tr>
<tr><td>Nil</td><td>9.1.4 Second new 66 kV circuit from BLTS</td><td>Nil</td></tr>
<tr><td colspan="3">9.1.5 3rd Transformer and 66 kV Works at FT</td></tr>
<tr><td rowspan="2">(Tullamarine Cluster)
KTS-TMA-MAT-KTS
KTS-AW-NDT-PV-KTS</td><td colspan="3">9.2.1 New KTS-TMA 66 kV line
9.2.2 Reconfigure existing KTS-TMA to be KTS-MAT-MDT 66 kV line
9.2.3 Augment KTS-AW 66 kV line</td></tr>
<tr><td>Nil</td><td>9.2.4 New KTS-ADT-VDT 66 kV line and 9.2.5 New</td><td>Nil</td></tr>
</table>

<table>
<tr><th>Asset Limitation</th><th>Option 1
Do Nothing</th><th>Option 2
Base</th><th>Option 3
High</th><th>Option 4
Low</th></tr>
<tr><td></td><td rowspan="5"></td><td></td><td>KTS-NDT2.5 66 kV line or

9.2.6 TMTS New Sub-Transmission Loop or

9.2.7 SYTS New Sub-Transmission Loop</td><td></td></tr>
<tr><td rowspan="2">(Heidelberg Cluster)
TTS-NEI-NH-WT-TTS
TTS-PTN-EPN-EP-TTS</td><td colspan="3">9.3.4 Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop</td></tr>
<tr><td>Nil</td><td>9.3.5 Third line into TTS-NEI-NH-WT-TTS</td><td>Nil</td></tr>
<tr><td>(Heidelberg Cluster)
NH & EPN</td><td>Load transfer EPN to NH</td><td>9.3.1 EPN Third Transformer
9.3.3 New Zone Substation to offload NH and EPN</td><td>Load transfer EPN to NH</td></tr>
<tr><td rowspan="2">(Heidelberg Cluster)
BTS-FF-BTS</td><td colspan="3">Nil</td></tr>
<tr><td>9.3.10 Augment BTS-FF 22 kV Loop</td><td>Nil</td><td colspan="2">9.3.8 Reconductor BTS-FF 181</td></tr>
<tr><td rowspan="2">(Heidelberg Cluster)
FF</td><td></td><td colspan="3">9.3.9 FF #4 6.6 kV Bus</td></tr>
<tr><td></td><td>9.3.6 Fourth transformer at FF</td><td>9.3.7 FF Conversion
9.3.8 Reconductor BTS-FF 181</td><td>9.3.6 Fourth transformer at FF</td></tr>
<tr><td>(Norther Growth Corridor Cluster)
TTS-BD-BMS-COO-VCO-TTS</td><td></td><td>Nil</td><td>9.4.1 TTS New Sub-Transmission Loop</td><td>Nil</td></tr>
</table>

Asset Limitation	Option 1 Do Nothing	Option 2 Base	Option 3 High	Option 4 Low
(Norther Growth Corridor Cluster) SMTS-ST-SSS-SMTS		9.4.2 ST-SSS 66 kV Line Extension		
		Nil	9.4.3 SMTS New Sub-Transmission Loop Or 9.4.5 DBTS New Sub-Transmission Loop	Nil

5.2 Options Project and On-going Operational Costs

Table 5-3 summarises the credible network solution capital costs and scope of works, and the identified optimum economic timing of each solution based on the EUE risk of associated network limitations.

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)[26]	Network Limitation	Optimum Timing[27]
Tie TH-FW 66kV line New 66kV line incomer at FW No.2 66kV bus	9.1.1	2,3	[redacted]	238	BLTS-BKN-TH-BLTS	2031
			[redacted]	146		2026
Second new 66 kV circuit from BLTS	9.1.4	3	[redacted]	621		2030
3rd Transformer and 66 kV Works at FT	9.1.5	2,3,4	Refer 11 kV Central NDS			
New KTS-TMA 66 kV line	9.2.1	2,3,4	[redacted]	1300	KTS-TMA-MAT-KTS and KTS-AW-NDT-PV-KTS	2027
Reconfigure existing KTS-TMA to be KTS-MAT-MDT 66 kV line	9.2.2	2,3,4	[redacted]	798		2026
Augment KTS-AW 66 kV line	9.2.3	2,3,4	[redacted]	239		2028
New KTS-ADT-VDT 66 kV line New KTS-NDT2.5 66 kV line	9.2.4 9.2.5	3 (only one of these three alternative solutions)	[redacted] [redacted]	800 800		2028 2035
TMTS New Sub-Transmission Loop	9.2.6		[redacted] [redacted] [redacted]	3,219		2028
SYTS New Sub-Transmission Loop	9.2.7		[redacted] [redacted] [redacted]	3,634		2029
New KTS-ATK 66 kV line	9.2.8	3	[redacted]	929	KTS-SHM-SBY-KTS	2028
EPN Third Transformer	9.3.1	3	[redacted]	725	NH, EPN	2030
New Zone Substation to offload NH and EPN	9.3.3	3	[redacted]	1,191		2030

[26] Based on 5.5% discount rate.

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

Credible Network Solutions	Scope of Work Section	Option	Capital Cost ($M)	Annual Cost ($k pa)[26]	Network Limitation	Optimum Timing[27]
Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop	9.3.4	2,3,4	Refer 22kV Central NDS		TTS-NEI-NH-WT-TTS and TTS-PTN-EPN-EP-TTS	
Third line into TTS-NEI-NH-WT-TTS	9.3.5	3	[redacted]	1,189		2039
Fourth transformer at FF	9.3.6	2,4	[redacted]	311	FF	2035+
FF Conversion	9.3.7	3	[redacted]	181		2035
Augment BTS-FF 22 kV Loop	9.3.10	2,3	[redacted]	667	BTS-FF-BTS	2027
Reconductor BTS-FF 181	9.3.8	3,4	[redacted]	135	BTS-FF-BTS	2026
FF #4 6.6 kV Bus	9.3.9	2,3,4	Committed		FF	2026
TTS New Sub-Transmission Loop	9.4.1	3	[redacted]	1,140	TTS-BD-BMS-COO-VCO-TTS	2035+
ST-SSS 66 kV Line Extension	9.4.2	2,3,4	Committed		SMTS-ST-SSS-SMTS	2026
SMTS New Sub-Transmission Loop	9.4.3	3 (only one of these two alternative solutions)	[redacted]	2,538		2033
DBTS New Sub-Transmission Loop	9.4.5		[redacted]	2,486		2033

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.

Table 5-4: Summary of Option Costs ($M Real 2024)[28]

Cost	Option 1	Option 2	Option 3	Option 4
Option total capital cost	**0.0**	***51.6***	***222.1***	***33.9***
PV of total capital cost	0.0	47.2	176.4	31.2
PV of O&M cost	0.0	7.0	25.1	4.7
PV of option total capital and O&M cost	**0.0**	**54.2**	**201.5**	**35.8**

[28] All augmentation options include the same future major customer project capital expenditure profile being $5.5 million in 2028, $5.0 million in 2029, $3.2 million in 2030 and $2.3 million in 2031 (Real 2024).

5.3 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.

5.3.1 Option 2 – Base Development Plan

Table 5-5 details the zone substation and sub-transmission EUE for Option 2 over the planning horizon for the identified network limitations. This plan is developed to eliminate at least 50% of the upstream and connection EUE risk associated with the do nothing option.

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

Asset	BLTS-BKN-TH-BLTS	KTS-TMA-MAT-KTS	KTS-AW-NDT-PV-KTS	TTS-BD-BMS-COO-VCO-TTS	SMTS-ST-SSS-SMTS	TTS-NEI-NH-WT-TTS	TTS-PTN-EPN-EP-TTS	NH & EPN	BTS-FF-BTS	FF	Total
2025	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	8.8	0.0	8.8
2026	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	13.5	0.0	13.5
2027	0.0	0.0	0.0	0.0	0.0	220.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	38.1	0.0	0.0	0.0	168.6	0.0	0.5	0.0	0.0	38.6
2029	0.0	750.0	0.0	0.0	0.0	361.3	0.0	4.1	0.0	0.0	754
2030	39.4	750.2	0.0	0.0	0.0	697.0	0.0	14.6	0.0	0.0	804
2031	0.0	753.4	0.0	0.0	0.0	750.0	0.0	16.6	0.0	0.0	770
2032	0.0	763.8	0.0	0.0	0.4	750.0	0.0	18.7	0.0	0.0	783
2033	0.0	779.4	30.4	0.0	50	750.0	0.0	20.7	0.0	0.0	880
2034	0.0	808.0	245.8	0.0	338	750.0	0.1	22.8	0.0	0.0	1,414

5.3.2 Option 3 – High Development Plan

Table 5-6 details the zone substation and sub-transmission EUE for Option 3 over the planning horizon for the identified network limitations. This plan is developed to eliminate most the upstream and connection EUE risk associated with the do nothing option.

Table 5-6: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 3

Asset	BLTS-BKN-TH-BLTS	KTS-TMA-MAT-KTS	KTS-AW-NDT-PV-KTS	TTS-BD-BMS-COO-VCO-TTS	SMTS-ST-SSS-SMTS	TTS-NEI-NH-WT-TTS	TTS-PTN-EPN-EP-TTS	NH & EPN	BTS-FF-BTS	FF	Total
2025	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	8.8	0.0	**8.8**
2026	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	13.5	0.0	**0.0**
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	39.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**39.4**
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.1**
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	**0.1**
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	**0.1**
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

5.3.3 Option 4 – Low Development Plan

Table 5-7 details the zone substation and sub-transmission EUE for Option 4 over the planning horizon for the identified network limitations. This plan is developed to eliminate up to 50% of the upstream and connection EUE risk associated with the do nothing option.

Table 5-7: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 4

BLTS-BKN-TH-BLTS	KTS-TMA-MAT-KTS	KTS-AW-NDT-PV-KTS	TTS-BD-BMS-COO-VCO-TTS	SMTS-ST-SSS-SMTS	TTS-NEI-NH-WT-TTS	TTS-PTN-EPN-EP-TTS	NH & EPN	BTS-FF-BTS	FF	Total
0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	8.8	0.0	**8.8**
0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	6.8	0.0	**6.8**
0.0	0.0	0.0	0.0	0.0	220.0	0.0	0.0	19.0	0.0	**19.0**
0.0	38.1	0.0	0.0	0.0	168.6	0.0	0.9	42.0	0.0	**81.0**
0.0	750.0	0.0	0.0	0.0	361.3	0.0	8.1	78.3	0.0	**836**
39.4	750.2	0.0	0.0	0.0	697.0	0.0	29	128.1	0.0	**947**
315.0	753.4	0.0	0.0	0.0	750.0	0.0	16.6	184.1	0.0	**1,269**

1,350.0	763.8	0.0	0.0	0.4	750.0	0.0	18.7	270.6	0.0	**2,403**
1,350.0	779.4	30.4	0.0	49.9	750.0	0.0	20.7	415.6	0.0	**2,646**
1,350.0	808.0	245.8	0.0	338	750.0	0.1	22.8	619.3	0.0	**3,384**

6. Economic Evaluation

This section presents the results of an economic cost-benefit analysis undertaken on each option. It considers 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 FY2027-31 regulatory control period are included which address all of the identified network needs over this 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 and 3 have the highest net economic benefits of all options considered.

Table 6-1: Summary of NPV Cost-Benefit Analysis ($M Real 2024)[29]

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 – Base Development Plan	51.6	54.2	473	418	2
Option 3 – High Development Plan	230.2	207.2	676	469	1
Option 4 – Low Development Plan	33.9	35.8	254	218	5
Option 6 – BESS Plan	0	352.9	676	323	3
Option 7 – DM Plan	0	427.5	676	249	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; and
- Achieving 30% lower capital costs across all projects with an associated reduction in the O&M.

Table 6-3 presents the results for the sensitivity analysis for NPV.

[29] Refer to Attachment Major Customers economic assessment model for cost benefit analysis calculations.

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
Option 1 - Do Nothing	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2 – Base Development Plan	418	371	466	389	451	402	435
Option 3 – High Development Plan	469	401	537	437	506	407	531
Option 4 – Low Development Plan	218	193	244	203	234	208	229

Option 2 and 3 remains the options with the highest net economic benefits for all credible sensitivities.

7. Recommendation and Next Steps

The preferred network development plan is to implement Option 2 (Base Development Plan), but retain the flexibility to move to Option 3 (High Development Plan) instead as an alternative.

The preferred Option 2 provides a 20-year present value net market benefit of $418 million for the weighted maximum demand scenario, with a present value of $47.2 million of capital investment, of which $30.9 million is required within the FY2027-31 regulatory control period. 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.

In making this decision we took into account:

- We do not need to make a decision on whether to implement option 2 or 3 until around 2027, as both Option 2 and Option 3 are identical until 2028.
- The demand forecast, underpinning this strategy and the economic analysis, is based on a moderated view of the customer load requirements, for example a longer time to ramp-up and reach a lower level of maximum demand. Given that that the data-centre boom is just starting, we do not yet have a long-term time series of actual data to test and refine these assumptions.
- There is a material difference in augmentation requirements and capital expenditure between Option 2 ($51.6 million) and Option 3 ($230.2 million).

Given these factors, and the significant difference in capex, the preferred network development plan is to implement Option 2 (Base Development Plan)), focusing on the no-regrets investments and continue monitoring the major customer and data centre connection pipeline. We will regularly refresh our analysis with a view to identify whether we need to shift to Option 3 (High Development Plan). Table 7-3 and Table 7-4 list the additional and contingent projects based on defined network cluster to shift to from Option 2 to Option 3 from year 2028 onwards.

7.1 Recommended Upstream Development Plan

The preferred network development plan (Option 2) to address the identified network limitations include the following projects:

Table 7-1: Option 2 – Base Development Plan

Timing	Projects	Capital Cost ($M, Real 2024)
2026	FF #4 6.6 kV Bus	Refer to published RIT-D
2026	ST-SSS 66 kV Line Extension	[redacted]
2026	New 66kV line incomer at FW No.2 66kV bus	[redacted]
2027	Augment BTS-FF 22 kV Loop	[redacted]
2027	Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop	Refer to 22kV Central Area NDS
2027	Load transfer EPN to NH03 and NH05	[redacted]
2028	Augment KTS-AW 66 kV line	[redacted]
2028	Future major customer projects	[redacted]

Timing	Projects	Capital Cost ($M, Real 2024)
2029	3rd Transformer and 66 kV Works at FT	Refer 11 kV Central Area NDS
2029	Future major customer projects	[redacted]
2030	Future major customer projects	[redacted]
2031	Tie TH-FW 66kV line	[redacted]
2031	Future major customer projects	[redacted]
	Total	**51.6**
	Present Value Total	**47.2**

The estimated total capital cost of Option 2 for JEN to address the identified network limitations is $51.6 million ($2024, Real), of which $20.7 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 2 - Base Development Plan, project within FY2027-31 regulatory control period

Timing	Projects	Capital Cost ($M, Real 2024)[30]
2026	New 66kV line incomer at FW No.2 66kV bus	[redacted]
2027	Augment BTS-FF 22 kV Loop	[redacted]
2027	Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop	Refer to 22kV Central Area NDS
2027	Load transfer EPN to NH03 and NH05	[redacted]
2028	Augment KTS-AW 66 kV line	[redacted]
2028	Future major customer projects	[redacted]
2029	3rd Transformer and 66 kV Works at FT	Refer 11 kV Central Area NDS
2029	Future major customer projects	[redacted]
2030	Future major customer projects	[redacted]
2031	Tie TH-FW 66kV line	[redacted]
2031	Future major customer projects	[redacted]
	Total	**30.9**

30 $20.7M of the recommended base development plan is outside the FY2027-31 regulatory control period.

Table 7-3 lists the additional projects based on defined network cluster to shift to from Option 2 to Option 3 over the 10 year period from year 2028.

Table 7-3: List of additional projects to shift from Option 2 to Option 3 from 2028

Timing	Projects	Capital Cost ($M, Real 2024)
2028	New KTS-ADT-VDT 66 kV line (Tullamarine Cluster)	[redacted]
2028	New KTS-ATK 66 kV line (Tullamarine Cluster)	[redacted]
2030	EPN Third Transformer (Heidelberg Cluster)	[redacted]
2030	New Zone Substation to offload NH and EPN (Heidelberg Cluster)	[redacted]
2030	Second new 66 kV circuit from BLTS	[redacted]
2033	SMTS New Sub-Transmission Loop (Northern Growth Cluster)	[redacted]
2035	New KTS-NDT2.5 66 kV line	[redacted]
2035	Third line into TTS-NEI-NH-WT-TTS (Heidelberg Cluster)	[redacted]
2035	FF Conversion (Heidelberg Cluster)	[redacted]
2035	TTS New Sub-Transmission Loop (Northern Growth Cluster)	[redacted]
	Total	**175.9**

Table 7-4 lists the contingent projects based on defined network cluster to shift to from Option 2 to Option 3 within the FY2027-31 regulatory control period.

Table 7-4: List of contingent projects from Option 2 to Option 3 within FY2027-31 regulatory control period

Timing	Projects	Capital Cost ($M, Real 2024)
2028	New KTS-ADT-VDT 66 kV line (Tullamarine Cluster)	[redacted]
2028	New KTS-ATK 66 kV line (Tullamarine Cluster)	[redacted]
2030	EPN Third Transformer (Heidelberg Cluster)	[redacted]
2030	New Zone Substation to offload NH and EPN (Heidelberg Cluster)	[redacted]
	Total	**70.3**

The costs and projects only relate to upstream Jemena network limitations whose scopes of work are detailed in Appendix B – Scopes of Work for Upstream Augmentations. They do not include the works needed to connect each major customer as summarised in Table 2-2 (costs subject to each customer connection proceeding), nor the works needed at the transmission connection level (pass-through costs). The customer connections scopes of work are detailed in Appendix C – Scopes of Work for Customer Connection Assets, and the transmission connection scopes of work are detailed in Appendix E – Scopes of Work for Terminal Stations.

8. Appendix A – Customer Connection and Upstream Augmentation Projects

Appendix A – Customer Connection and Upstream Augmentation Projects provides the likely timing of customer connection projects and optimum timing of upstream augmentation projects for each maximum demand growth scenario.

8.1 Low Demand Growth Scenario

Identifier	Connection Project	Trigger	Timing	Upstream Augmentation Project	Trigger	Timing
DC07	New BKN ZSS 66/11kV 2 x 33 MVA (Inflight)	Connection Agreement	2023			
DC07	Loop BKN into BLTS-TH No.1 66kV Line (Inflight)	Connection Agreement	2023			
DC07	Third BKN ZSS 66/22kV 33 MVA Transformer and Bus	DC7 Load > 33 MVA	2026			
DC07	9.1.2 New BLTS-BKN 66 kV line	DC7 Load > 50 MVA	2030			
DC02	New NDF ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2030			
DC02	Loop NDF into BLTS-TH No.2 66kV Line	Connection Agreement	2029			
DC09	New PDW ZSS 66/22kV 2 x 50 MVA	Connection Agreement	2028			
DC09	Loop PDW into BLTS-TH No.2 66kV Line	Connection Agreement	2028			
DC19	New HDY ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2028			
DC19	Two new BLTS-HDY 66kV lines	Connection Agreement	2028			
DC06	Committed Project	Connection Agreement	2024			
A54	New TH21 22kV Feeder (1.0km U/G, 375A)	Connection Agreement	> 2035			
A923	Committed Project	Connection Agreement	2024			
A997	Committed Project	Connection Agreement	2023			
A278	First and second 11 kV feeder from FT	Connection Agreement	2027	9.3.8 Reconductor BTS-FF 181	BTS-FF-BTS overload	2026
A279	Third and fourth 11 kV feeder from FT	Cust. Load > 7 MVA	2030	9.1.5 3rd Transformer and 66kV Works at FT	FT overload	2029
DC01	New NDT ZSS 66/22kV 2 x 50MVA (Inflight)	Connection Agreement	2023	9.2.3 Augment KTS-AW 66 kV line	KTS-TMA-MAT-KTS and KTS-AW-NI	2028
DC01	Third NDT ZSS 66/22kV 50 MVA Transformer and Bus	DC1 Load > 50 MVA	2026			
DC12	New VDT ZSS 66/22kV 2 x 50 MVA	Connection Agreement	2026			
DC12	Loop VDT into KTS-NDT 66kV line	Connection Agreement	2025			
DC04	New MDT ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2026			
DC04	9.2.1 New KTS-TMA 66kV line	Connection Agreement	2027			
DC04	9.2.2 Reconfigure existing KTS-TMA to be KTS-MAT-MDT 6	Connection Agreement	2026			
DC04	Third MDT ZSS 66/22kV 75 MVA Transformer and Bus	DC4 Load > 75 MVA	2030			
A60	Augment MAT ZSS 66/22kV with 2 x 33 MVA new transfor	MAT Load > 60 MVA	2027			
DC10	New MDW ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2029			
DC10	MAT-MDT 66kV line extension to MDW	Connection Agreement	2029			
DC17	New ATK ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027			
DC18	New ADT ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2026			
DC18	Loop ADT into TMA-MAT 66kV line	Connection Agreement	2026			
TEMPB	New 22kV feeder from AW	Connection Agreement	2025			
DC11	New DC11 ZSS 66/22kV 2 x 50MVA	Connection Agreement	2026	9.4.2 ST-SSS 66kV Line Extension	SMTS-ST-SSS-SMTS overload	2026
DC20	New DC20 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027			
DC21	New DC21 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2029			
DC22	New DC22 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2030			
A50	Two new feeders from CBN	Connection Agreement	2026	Refer to Northern Growth Corridor NDS	ST overload	
A197	NEL ZSS 66/22kV (Existing)	Connection Agreement	2023	9.3.4 Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop	TTS-NEI-NH-WT-TTS and TTS-PTN-E	2027
A516	New feeders - NEL-012 and NEL-025	NEL load increase	2026	9.3.2 Augment TTS-PTN-EPN-EP-TTS 66 kV loop	TTS-PTN-EPN-EP-TTS overload	2025
TEMP16	Extend 22kV feeder EPN34 (1.7km O/H, 1025A 66kV const	Cust. Load > 15 MVA	2027	9.3.9 FF #4 6.6kV Bus	FF overload	2026
A17	Install one new 6.6kV feeder to the customer site from FF	Connection Agreement	2028	9.3.6 Fourth transformer at FF	FF overload	2035
A265	[redacted]	Connection Agreement	2027			
A56	[redacted]	Connection Agreement	2026			

8.2 Base Demand Growth Scenario – Preferred Development Plan

Identifier	Connection Project	Trigger	Timing	Upstream Augmentation Project	Trigger
DC07	New BKN ZSS 66/11kV 2 x 33 MVA (Inflight)	Connection Agreement	2023	9.1.1 Tie TH-FW 66kV line	BLTS-BKN-TH-BLTS overload
DC07	Loop BKN into BLTS-TH No.1 66kV Line (Inflight)	Connection Agreement	2023	9.1.1 New 66kV line incomer at FW No.2 66kV bus	BLTS-BKN-TH-BLTS overload
DC07	Third BKN ZSS 66/22kV 33 MVA Transformer and Bus	DC7 Load > 33 MVA	2026		
DC07	9.1.2 New BLTS-BKN 66 kV line	DC7 Load > 50 MVA	2029		
DC02	New NDF ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2029		
DC02	Loop NDF into BLTS-TH No.2 66kV Line	Connection Agreement	2028		
DC09	New PDW ZSS 66/22kV 2 x 50 MVA	Connection Agreement	2028		
DC09	Loop PDW into BLTS-TH No.2 66kV Line	Connection Agreement	2028		
DC19	New HDY ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2028		
DC19	Two new BLTS-HDY 66kV lines	Connection Agreement	2028		
DC19	Third HDY ZSS 66/22kV 75 MVA Transformer and Bus	DC19 Load > 75 MVA	> 2035		
DC06	Committed Project	Connection Agreement	2024		
A54	New TH21 22kV Feeder (1.0km U/G, 375A)	Connection Agreement	2030		
A923	Committed Project	Connection Agreement	2024	9.3.8 Reconductor BTS-FF 181	BTS-FF-BTS overload
A997	Committed Project	Connection Agreement	2023	9.3.10 Augment BTS-FF 22kV Loop	BTS-FF-BTS overload
A278	First and second 11 kV feeder from FT	Connection Agreement	2027	9.1.5 3rd Transformer and 66kV Works at FT	FT overload
A279	Third and fourth 11 kV feeder from FT	Cust. Load > 7 MVA	2029	Refer to 11 kV Central Area NDS	FT overload
DC01	New NDT ZSS 66/22kV 2 x 50MVA (Inflight)	Connection Agreement	2023	9.2.3 Augment KTS-AW 66 kV line	KTS-TMA-MAT-KTS and KTS-AW-NI
DC01	Third NDT ZSS 66/22kV 50 MVA Transformer and Bus	DC1 Load > 50 MVA	2026		
DC12	New VDT ZSS 66/22kV 2 x 50 MVA	Connection Agreement	2026		
DC12	Loop VDT into KTS-NDT 66kV line	Connection Agreement	2025		
DC04	New MDT ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2026		
DC04	9.2.1 New KTS-TMA 66kV line	Connection Agreement	2027		
DC04	9.2.2 Reconfigure existing KTS-TMA to be KTS-MAT-MDT 6	Connection Agreement	2026		
DC04	Third MDT ZSS 66/22kV 75 MVA Transformer and Bus	DC4 Load > 75 MVA	2029		
A60	Augment MAT ZSS 66/22kV with 2 x 33 MVA new transfor	MAT Load > 60 MVA	2027		
DC10	New MDW ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2028		
DC10	MAT-MDT 66kV line extension to MDW	Connection Agreement	2028		
DC17	New ATK ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027		
DC18	New ADT ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2026		
DC18	Loop ADT into TMA-MAT 66kV line	Connection Agreement	2026		
TEMPB	New 22kV feeder from AW	Connection Agreement	2025		
TEMPA	Extend 22kV feeder ST34	Connection Agreement	2026	9.4.2 ST-SSS 66kV Line Extension	SMTS-ST-SSS-SMTS overload
DC11	New DC11 ZSS 66/22kV 2 x 50MVA	Connection Agreement	2026		
DC20	New DC20 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027		
DC20	Third DC20 ZSS 66/22kV 75 MVA Transformer and Bus	DC20 Load > 75 MVA	> 2035		
DC21	New DC21 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2028		
DC21	Third DC21 ZSS 66/22kV 75 MVA Transformer and Bus	DC21 Load > 75 MVA	> 2035		
DC22	New DC22 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2029		
A50	Two new feeders from CBN	Connection Agreement	2026	Refer to Northern Growth Corridor NDS	ST overload
A197	NEL ZSS 66/22kV (Existing)	Connection Agreement	2023	9.3.4 Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop	TTS-NEI-NH-WT-TTS and TTS-PTN-E
A516	New feeders - NEL-012 and NEL-025	NEL load increase	2026	9.3.2 Augment TTS-PTN-EPN-EP-TTS 66 kV loop	TTS-PTN-EPN-EP-TTS overload
A53B	New EPN 22kV Feeder (5.0km U/G, 400A)	Connection Agreement	2029	9.3.1 EPN Third Transformer	EPN overload
A53A	Two new EPN 22kV feeders (2 x 3.5km U/G, 400A)	Connection Agreement	2035	9.3.9 FF #4 6.6kV Bus	FF overload
TEMP16	Extend 22kV feeder EPN34 (1.7km O/H, 1025A 66kV const	Cust. Load > 15 MVA	2027	9.3.6 Fourth transformer at FF	FF overload
TEMP5	Install one new 6.6kV feeder to the customer site from FF	Connection Agreement	2026		
A17	Install two new 6.6kV feeders to the customer site from F	Connection Agreement	2027		
A265	[redacted]	Connection Agreement	2027		
A56		Connection Agreement	2026		

8.3 High Demand Growth Scenario

Identifier	Connection Project	Trigger	Timing	Upstream Augmentation Project	Trigger	Timing
DC07	New BKN ZSS 66/11kV 2 x 33 MVA (Inflight)	Connection Agreement	2023	9.1.1 Tie TH-FW 66kV line	BLTS-BKN-TH-BLTS overload	2031
DC07	Loop BKN into BLTS-TH No.1 66kV Line (Inflight)	Connection Agreement	2023	9.1.1 New 66kV line incomer at FW No.2 66kV bus	BLTS-BKN-TH-BLTS overload	2031
DC07	Third BKN ZSS 66/22kV 33 MVA Transformer and Bus	DC7 Load > 33 MVA	2026	9.1.3 Second new 66kV circuit from BLTS	BLTS-BKN-TH-BLTS overload	2030
DC07	9.1.2 New BLTS-BKN 66 kV line	DC7 Load > 50 MVA	2028			
DC07	Fourth BKN ZSS 66/22kV 33 MVA Transformer and Bus	DC7 Load > 66 MVA	2034			
DC02	New NDF ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2028			
DC02	Loop NDF into BLTS-TH No.2 66kV Line	Connection Agreement	2027			
DC02	Third NDF ZSS 66/22kV 75 MVA Transformer and Bus	DC2 Load > 75 MVA	> 2035			
DC09	New PDW ZSS 66/22kV 2 x 50 MVA	Connection Agreement	2027			
DC09	Loop PDW into BLTS-TH No.2 66kV Line	Connection Agreement	2027			
DC09	Third PDW ZSS 66/22kV 50 MVA Transformer and Bus	DC9 Load > 50 MVA	> 2035			
DC19	New HDY ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027			
DC19	Two new BLTS-HDY 66kV lines	Connection Agreement	2027			
DC19	Third HDY ZSS 66/22kV 75 MVA Transformer and Bus	DC19 Load > 75 MVA	> 2035			
DC19	Fourth HDY ZSS 66/22kV 75 MVA Transformer and Bus	DC19 Load > 150 MVA	> 2035			
DC06	Committed Project	Connection Agreement	2024			
DC25	New DC25 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	> 2035			
DC26	New DC26 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	> 2035			
A54	New TH21 22kV Feeder (1.0km U/G, 375A)	Connection Agreement	2028			
A923	Committed Project	Connection Agreement	2024			
A997	Committed Project	Connection Agreement	2023	9.3.10 Augment BTS-FF 22kV Loop	BTS-FF-BTS overload	2027
A278	First and second 11 kV feeder from FT	Connection Agreement	2026	9.1.5 3rd Transformer and 66kV Works at FT	FT overload	2029
A279	Third and fourth 11 kV feeder from FT	Cust. Load > 7 MVA	2028	Refer to 11 kV Central Area NDS	FT overload	
DC01	New NDT ZSS 66/22kV 2 x 50MVA (Inflight)	Connection Agreement	2023	9.2.4 New KTS-ADT-VDT 66 kV line	KTS-TMA-MAT-KTS and KTS-AW-N	2028
DC01	Third NDT ZSS 66/22kV 50 MVA Transformer and Bus	DC1 Load > 50 MVA	2026	9.2.5 New KTS-NDT2.5 66 kV line	KTS-TMA-MAT-KTS and KTS-AW-N	2035
DC01	Establish second NDT ZSS 66/22kV 2 x 50MVA	DC1 Load > 100 MVA	> 2035	9.2.6 TMTS New Sub-Transmission Loop	KTS-TMA-MAT-KTS and KTS-AW-N	2028
DC12	New VDT ZSS 66/22kV 2 x 50 MVA	Connection Agreement	2026	9.2.3 Augment KTS-AW 66 kV line	KTS-TMA-MAT-KTS and KTS-AW-N	2028
DC12	Loop VDT into KTS-NDT 66kV line	Connection Agreement	2025	9.2.7 SYTS New Sub-Transmission Loop	KTS-TMA-MAT-KTS and KTS-AW-N	2029
DC12	Third VDT ZSS 66/22kV 50MVA Transformer and Bus	DC12 Load > 50 MVA	> 2035			
DC04	New MDT ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2026			
DC04	9.2.1 New KTS-TMA 66kV line	Connection Agreement	2027			
DC04	9.2.2 Reconfigure existing KTS-TMA to be KTS-MAT-MDT 6	Connection Agreement	2026			
DC04	Third MDT ZSS 66/22kV 75 MVA Transformer and Bus	DC4 Load > 75 MVA	2028			
A60	Augment MAT ZSS 66/22kV with 2 x 33 MVA new transfor	MAT Load > 60 MVA	2027			
DC10	New MDW ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027			
DC10	MAT-MDT 66kV line extension to MDW	Connection Agreement	2027			
DC17	New ATK ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027			
DC17	Third ATK ZSS 66/22kV 75 MVA Transformer and Bus	DC17 Load > 75 MVA	> 2035			
DC18	New ADT ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2026			
DC18	Loop ADT into TMA-MAT 66kV line	Connection Agreement	2026			
DC18	Third ADT ZSS 66/22kV 75 MVA Transformer and Bus	DC18 Load > 75 MVA	2034			
DC27	New DC27 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	> 2035			
TEMPB	New 22kV feeder from AW	Connection Agreement	2025			
TEMPA	Extend 22kV feeder ST34	Connection Agreement	2026	9.4.3 SMTS New Sub-Transmission Loop	SMTS-ST-SSS-SMTS overload	2032
DC11	New DC11 ZSS 66/22kV 2 x 50MVA	Connection Agreement	2026	9.4.5 DBTS New Sub-Transmission Loop	SMTS-ST-SSS-SMTS overload	2032
DC11	Third DC11 ZSS 66/22kV 50 MVA Transformer and Bus	DC11 Load > 50MVA	> 2035	9.4.1 TTS New Sub-Transmission Loop	TTS-BD-BMS-COO-VCO-TTS overloa	2035
DC20	New DC20 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2027	9.4.2 ST-SSS 66kV Line Extension	SMTS-ST-SSS-SMTS overload	2026
DC20	Third DC20 ZSS 66/22kV 75 MVA Transformer and Bus	DC20 Load > 75 MVA	> 2035			
DC20	Fourth DC20 ZSS 66/22kV 75 MVA Transformer and Bus	DC20 Load > 150 MVA	> 2035			
DC21	New DC21 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2030			
DC21	Third DC21 ZSS 66/22kV 75 MVA Transformer and Bus	DC21 Load > 75 MVA	2028			
DC21	Fourth DC21 ZSS 66/22kV 75 MVA Transformer and Bus	DC21 Load > 150 MVA	> 2035			
DC22	New DC22 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	2028			
DC22	Third DC22 ZSS 66/22kV 75 MVA Transformer and Bus	DC22 Load > 75 MVA	> 2035			
DC23	New DC23 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	> 2035			
DC24	New DC24 ZSS 66/22kV 2 x 75 MVA	Connection Agreement	> 2035			
A50	Two new feeders from CBN	Connection Agreement	2026	Refer to Northern Growth Corridor NDS	ST overload	
A197	NEL ZSS 66/22kV (Existing)	Connection Agreement	2023	9.3.4 Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop	TTS-NEI-NH-WT-TTS and TTS-PTN-E	2027
A516	New feeders - NEL-012 and NEL-025	NEL load increase	2026	9.3.1 EPN Third Transformer	EPN overload	2030
A53B	New EPN 22kV Feeder (5.0km U/G, 400A)	Connection Agreement	2026	9.3.3 New Zone Substation to offload NH and EPN	NH and EPN overload	2030
A53A	Two new EPN 22kV feeders (2 x 3.5km U/G, 400A)	Connection Agreement	2029	9.3.2 Augment TTS-PTN-EPN-EP-TTS 66 kV loop	TTS-PTN-EPN-EP-TTS overload	2025
TEMP16	Extend 22kV feeder EPN34 (1.7km O/H, 1025A 66kV const	Cust. Load > 15 MVA	2027	9.3.5 Third line into TTS-NEI-NH-WT-TTS	TTS-NEI-NH-WT-TTS overload	2035
TEMP16	New LTU ZSS 66/22kV 2 x 75 MVA	Cust. Load > 15 MVA	2034	9.3.9 FF #4 6.6kV Bus	FF overload	2026
TEMP16	Third LTU ZSS 66/22kV 75 MVA Transformer and Bus	Cust. Load > 75 MVA	> 2035	9.3.7 FF Conversion	BTS-FF-BTS overload	2035
TEMP5	Install one new 6.6kV feeder to the customer site from FF	Connection Agreement	2025	9.3.8 Reconductor BTS-FF 181	BTS-FF-BTS overload	2035
A17	Install three new 6.6kV feeders to the customer site from	Connection Agreement	2026			
A265	[redacted]	Connection Agreement	2027			
A56	[redacted]	Connection Agreement	2026			

9. Appendix B – Scopes of Work for Upstream Augmentations

9.1 Footscray Cluster

The following single line schematic diagram shows the existing sub-transmission network in the Footscray Cluster of prospective major customers and data centres.

[redacted]

9.1.1 Tie TH-FW 66kV line

This solution allows for major customer and data centre connections in the Footscray area.

[redacted]

The scope is to loop in and extend the BLTS-TH No.2 line to FW as shown using 5.0 km of overhead 66 kV line with 37/3.75 AAC 100/75^{o}C, and establishing a new 66 kV feeder exit at FW.

[redacted]

[redacted]

The new 66 kV line incomer at FW No.2 66kV bus component of this option is being undertaken as part of the FW rebuild project and is therefore a committed project and to be delivered by 2026.

9.1.2 New BLTS-BKN 66 kV line

This solution allows for major customer and data centre connections in the Brooklyn area. The scope is to establish the BLTS-BKN No.2 line using 1.0 km of overhead 66 kV line using 37/3.75 AAC 100/75^{o}C, and 1.5 km of underground cable sized for a rating of 1,200 Amps. This project is proposed to be fully funded by the customer.

[redacted]

[redacted]

The transmission connection works required within the terminal station to support this solution, are as described in Appendix E – Scopes of Work for Terminal Stations.

9.1.3 First new 66 kV circuit from BLTS

This solution allows for higher growth in major customer and data centre connections in the Footscray area. The scope includes

- the scope for solution 9.1.1;
- establishing a new 66 kV line to Footscray from Brooklyn Terminal Station using 3.5 km of underground cable sized for a rating of 1,200 Amps.

his solution appears as “DC19 - New BLTS-HDY 66 kV line” in the capex plan and is proposed to be fully funded by the customer.

[redacted]

[redacted]

The transmission connection works required within the terminal station to support this solution, are as described in Appendix E – Scopes of Work for Terminal Stations.

9.1.4 Second new 66 kV circuit from BLTS

This solution allows for higher growth in major customer and data centre connections in the Yarraville, Footscray (and Brooklyn) areas. The scope includes

- the scope for solution 9.1.3; and
- establishing a new 66 kV line to Yarraville from Brooklyn Terminal Station using 0.5 km of underground cable sized for a rating of 1,200 Amps.

[redacted]

[redacted]

The transmission connection works required within the terminal station to support this solution, are as described in Appendix E – Scopes of Work for Terminal Stations.

9.1.5 3rd Transformer and 66 kV Works at FT

Refer 11 kV Central Area NDS for further details.

9.2 Tullamarine Cluster

The following geospatial and single line schematic diagrams show the existing sub-transmission network in the Tullamarine Cluster of prospective major customers and data centres.

[redacted]

The following shows possible next stages towards an ultimate arrangement.

[redacted]

[redacted]

[redacted]

[redacted]

The following diagrams are possible ultimat sub-transmission arrangements for the Tullamarine Cluster.

[redacted]

[redacted]

9.2.1 New KTS-TMA 66 kV line

Refer to 9.2.2 for further details. This solution is a committed project funded by the customer and to be delivered by 2027.

9.2.2 Reconfigure existing KTS-TMA to be KTS-MAT-MDT 66 kV line

This solution augments the capacity of the KTS-TMA-MAT-KTS 66 kV loop for connection of new major customers and data centres for the Tullamarine Cluster by establishing a new KTS-TMA 66 kV line and reconfiguring the existing KTS-TMA to be KTS-MAT-MDT 66 kV line.

[redacted]

The scope involves installing, extending and upgrading 66 kV overhead lines shown in blue (new KTS-TMA) and red (extended and upgraded KTS-TMA renamed to KTS-MAT-MDT) above.

A new 66 kV bus No.7 and two new 66 kV feeder exits are required at KTS for this solution, as described in Appendix E – Scopes of Work for Terminal Stations.

This solution is a committed project and to be delivered by 2027.

9.2.3 Augment KTS-AW 66 kV line

This solution addresses the power flow imbalance that occurs between the circuits on the sub-transmission loop with KTS-AW carrying higher loadings than the KTS-PV 66 kV line and is at risk of overload under contingency conditions. The scope involves reconductoring the KTS-AW circuit to twin conductor for 4.9 km.

9.2.4 New KTS-ADT-VDT 66 kV line

This solution augments the capacity of the KTS-AW-NDT-PV-KTS 66 kV loop for connection of new major customers and data centres for the Tullamarine Cluster by establishing a new KTS-ADT-VDT 66 kV line and combining the KTS-TMA-MAT-KTS and KTS-AW-NDT-PV-KTS loops together.

[redacted]

The scope involves installing 66 kV overhead lines shown in yellow (new KTS-ADT-VDT) above.

9.2.5 New KTS-NDT2.5 66 kV line

This solution provides for the ultimate configuration of the Tullamarine Cluster sub-transmission network.

[redacted]

The scope involves installing 66 kV overhead lines shown in brown (new KTS-NDT2.5) above.

9.2.6 TMTS New Sub-Transmission Loop

This is one of two alternative solutions to be adopted if there is insufficient capacity at KTS to accommodate the load requirements of the prospective major customers and data centres in the Tullamarine Cluster.

[redacted]

The scope includes

- establish a new TMTS-MDT 66 kV feeder using a built with 37/3.75 AAC 100/75^{o}C from the TMTS feeder exit on Bus No.1 to the MDT zone substation, rebuilding 3.0km of the existing AW-PV feeder as double circuit, and 3.0km as new double circuit (with a new TMTS-AW feeder on Bus No.1), and 0.5 km as new single circuit.

- establish new TMTS-MDW No.1 and No.2 66 kV feeders using a new 8.0 km single circuit overhead line built with 37/3.75 AAC 100/75^{o}C from the TMTS feeder exits on Bus No.1 and No.2 to MDW.

- establish the new TMTS-PV 66 kV feeder using a new 3.0 km single circuit overhead line from the TMTS feeder exit on Bus No.2 to the existing AW-PV feeder.

- complete the new section of AW-PV 66 kV feeder using a new 5.5 km double circuit overhead line from AW to the existing AW-PV feeder along the same route as solution 9.2.4, with the second circuit for KTS-NDT No.2 continuing as a single circuit for 2.0 km back to KTS.

This solution requires the establishment of a new terminal station (TMTS) on a Jemena-owned site. The transmission connection works required within the terminal station to support this solution, are as described in Appendix E – Scopes of Work for Terminal Stations.
TMTS is a fallback solution if KTS125 is not able to be developed with larger / additional transformers, or if the load grows to a point where there is insufficient capacity at KTS to supply the total load. TMTS already has 220kV lines (4 circuits) going through the vacant site which can be cut in using only 220/66 kV transformation. TMTS is able to provide additional new 66 kV overhead lines from the east where there is no line easement congestion issues, allowing the data centres furthest from KTS to be supplied from TMTS. Jemena has also had major load connections interest in the Northern Growth Corridor Cluster as well (i.e., DC21, DC20). These could also be supplied by TMTS rather than also upgrading both TTS and SMTS. There are however, concerns with the since it is very close to residential areas. This could make approval challenging. Furthermore, the site is relatively small and could provide limited future growth at the proposed terminal station unless it is developed with GIS switchgear. Given the high level of uncertainty in any of the customers actually taking up their full load, it would be prudent to try to minimise the amount of capex upfront (no regrets investments). This would be to augment KTS at the appropriate time if possible before building a new terminal station. Hence this solution is only recommended for the High development scenario.

9.2.7 SYTS New Sub-Transmission Loop

This is the second of two alternative solutions to be adopted if there is insufficient capacity at KTS to accommodate the load requirements of the prospective major customers and data centres in the Tullamarine Cluster.

[redacted]

[redacted]

The scope involves establishing the existing Sydenham Terminal Station (SYTS) as a new 66 kV connection point from which new 66 kV feeders can be built to transfer the entire SHM/SBY sub-transmission loop (approximately 160 MVA) completely from KTS34 to SYTS. This will free up capacity and four 66 kV CB bays at KTS34 to support KTS125 in suppling the Tullamarine Cluster. It is also proposed to transfer AW/PV away from KTS125 to SYTS.

The scope includes:

- establish new SYTS-SBY No.2 and SYTS-PV 66 kV feeders built with 6.0 km double circuit 37/3.75 AAC 100/75^{o}C from the SYTS feeder exit on Bus No.3 to the corner of Melton Hwy and Plumpton Rd, through the transmission easements and along Melton Hwy. Remove the CB connection of this new PV line back at KTS and connect directly to the existing KTS-PV line at KTS;

- establish a new SYTS-AW 66 kV feeder using a new 4.0 km single circuit overhead line built with 37/3.75 AAC 100/75^{o}C from the SYTS feeder exit on Bus No.2 to Kings Rd. Remove the CB connection of this new AW line back at KTS and connect directly to the existing KTS-AW line at KTS;

- connect the existing 66 kV overhead line sections for the SHM/SBY loop into SYTS to establish SYTS-SBY No.1 and SYTS-SHM;

- install 6.0 km of 66 kV underground cable from KTS to VDT, sized for a rating of 1250 Amps from the PV circuit breaker bay at KTS;

- install 6.5 km of 66 kV underground cable from KTS to NDT, sized for a rating of 1250 Amps, from the AW circuit breaker bay at KTS;

This solution requires major augmentations to the SYTS terminal station. The transmission connection works required within the terminal station to support this solution, are as described in Appendix E – Scopes of Work for Terminal Stations.

SYTS has more room for growth than a TMTS solution with its larger footprint and is likely to have a lower risk of community concern. The sub-transmission arrangements compared to the KTS development are simpler networks. They utilise existing overhead pole lines and allow room for long-term growth in the Tullamarine Cluster for potential new major customer and data centre connections or expansions.

SYTS however, currently only has 550kV lines going into the site, therefore it would need to establish 2 x 500/220kV 1000MVA transformers, and at least 2 x 220/66 kV 225 MVA transformers, or route new 220 kV overhead lines out to the site, making it likely the most expensive solution out of the KTS, TMTS and SYTS transmission connection points options. Furthermore, two long runs of underground 66 kV cable are needed from KTS northward in the Tullamarine area, due to congestion of overhead 66 kV lines in the area. As such SYTS is a fallback solution if both TMTS or KTS cannot be developed (or expanded) to supply the total load.

As per the TMTS solution, given the high level of uncertainty in any of the customers actually taking up their full load, it would be prudent to try to minimise the amount of capex upfront (no regrets investments). This would be to augment KTS at the appropriate time if possible before augmenting SYTS. Hence this solution is only recommended for the High development scenario.

9.2.8 New KTS-ATK 66 kV line

This solution involves looping in an out DC17 of the existing KTS-SHM 66 kV line and installing a new 66 kV underground cable from KTS West group to the new ATK zone substation.

[redacted]

9.3 Heidelberg Cluster

9.3.1 EPN Third Transformer

This solution increases the capacity of EPN to alleviate the loading on this zone substation and to accommodate major customer connections. The scope involves installing a third 66/22 kV 20/33 MVA transformer and third buses at EPN, on the assumption the second transformer and bus is already installed. Install a minimum of two new 22 kV feeders into Heidelberg Heights area of 2.5 km each using 300 mm^2 Al xlpe.

[redacted]

9.3.2 Augment TTS-PTN-EPN-EP-TTS 66 kV loop

This solution involves increasing the capacity of the TTS-PTN-EPN-EP-TTS to facilitate accommodating major customer connections.

The scope of work includes:

- Reconductor under-rated sections of TTS-PTN, TTS-EP, and PTN-EPN 66 kV lines, a total of 10.7 km with 37/3.75 AAC (built to 100^{o}C/75^{o}C).

9.3.3 New Zone Substation to offload NH and EPN

This solution involves installing a new zone substation midway between NH and EPN to alleviate the loading on those zone substations and to accommodate major customer connections.

The scope of work includes:

- Extend the TTS-EP 66 kV line to a new zone substation at the major customer site using approximately 7.6 km of new single circuit 37/3.75 AAC 100/75°C overhead line.

- Establish a new 66/22 kV 20/33 MVA zone substation (with a single transformer initially) cutting into the extended TTS-EP 66 kV line.

The arrangement of this sub-transmission loop before and after installation of the new zone substation is shown below.

Existing

[redacted]

Proposed

[redacted]

9.3.4 Augment TTS-NH(NEI)-NEL-WT-TTS 66 kV loop

This solution increases the capacity of the 66 kV sub-transmission loops supplying into the Heidelberg Cluster to enable connection of major customer loads by tying the TTS-NEI-NH-WT-TTS loop with the TTS-PTN-EPN-EP-TTS loop, with two teed lines from NH teed into the EPN-PTN 66 kV line, and from NEI teed into the NEL-NH 66 kV line. The existing and proposed sub-transmission arrangements are shown below.

Existing

[redacted]

Proposed

[redacted]

The two teed lines are formed around EPN and NH as shown below. The existing EPN-PTN line becomes the EPN-NH-PTN line, and the existing TTS-NEI/NH and NEL-NH lines become the TTS-NEI and NEL-NEL-NH 66 kV lines.

[redacted]

The scope includes:

- Cutting into existing NEI-NH line segment at Waiora Road and run approximately 1.5 km of new single circuit 37/3.75AAC (built to 100^{o}C/75^{o}C) to tie onto existing NH-NEL line to create new line segment NEI-NEL-NH.

- Create a new 66 kV tie point on the existing EPN-PTN line and run approximately 3.3 km of new single circuit 37/3.75 AAC (built to 100^{o}C/75^{o}C) to connect to existing 66 kV line east of Waiora Road. This will create new line EPN-NH-PTN.

- Swap TTS-PTN and TTS-CS 66 kV lines at TTS to remove double circuit line risk of TTS-PTN and TTS-NEI circuits sharing the same pole line. Redirect TTS-PTN line north along Spring Street and into Stanworth Court by running approximately 0.4 km of new 37/3.75AAC (built to 100^{o}C/75^{o}C). Tie into the existing 66 kV line terminating into PTN. Run approximately 0.2 km of new 37/3.75AAC (built to 100^{o}C/75^{o}C) to tie onto existing 66 kV line to provide continuity to TTS-CS line.

- Reconductor 2.0 km of line on NEL-NH/NEI with new 37/3.75AAC overhead line (built to 100^{o}C/75^{o}C).

- Check 66 kV dropper at EPN (along PTN-EPN/NH segment) achieves a minimum rating of 1025A. Upgrade dropper if this requirement is not met.

- A new 66 kV line CB is required at NEI for the NEI-NEL-NH 66 kV line. NEI will need to be converted from a tee-off substation to a fully switched substation. A new 0.2 km return circuit of 37/3.75AAC overhead line (built to 100^{o}C/75^{o}C) from the new NEI 66 kV line CB to the corner of Sheehan Rd and Dougharty Rd may run above or on the same pole line as the other circuit if there is insufficient room to segregate.

- New 3-way protection schemes are required on each teed line at NEI, NEL, EPN and NH.

The rearrangements around PTN to swap the TTS-CS and TTS-PTN circuits and around NEI as described above are as shown below:

[redacted]

9.3.5 Third line into TTS-NEI-NH-WT-TTS

This solution increases the capacity of the 66 kV sub-transmission loops supplying into the Heidelberg Cluster to enable connection of a new major customer zone substation in the Bundoora area by providing an additional 66 kV line from TTS into the existing sub-transmission loops.

Existing

[redacted]

Proposed

[redacted]

The scope includes:

- the scope for solution 9.3.4;
- install 0.6 km of 3x 1/c 1200 mm^2 Cu 66 kV underground exit cables at TTS to Keon Parade along railway station carpark access road to achieve a rating of at least 1425A.
- install (by rebuilding existing HV lines) a 7.6 km new 66 kV line using dual (or bonded double circuit) 19/4.75AAC 100/75^{o}C conductor, from the end of the TTS exit cable in Keon Parade to NEI zone substation (teed into the TTS-NEI 66 kV line) to achieve a rating of at least 1425A. Note: some parts of EPN34 may be able to be converted to 66 kV in Sheehan Rd, reducing the overall length by 2.1 km.

The section of the new line closest to TTS in the north are shown below.

[redacted]

The sections of the new line in the centre and the south closest to NEI respectively are shown below.

[redacted]

9.3.6 Fourth transformer at FF

This solution addresses the overload limitation at FF zone substation. The scope of work is to install a 4th 22/6.6 kV 12/18 MVA transformer, assuming the No.3 transformer is already replaced and relocated.

[redacted]

9.3.7 FF Conversion

This is an alternative solution for addressing overload limitations at FF, particularly if there are space restrictions at FF, or issues with establishing new 6.6 kV feeders out of FF. The scope involves progressively converting the south-west 6.6 kV feeders of FF to 22 kV and connecting them directly to the BTS-FF181 22 kV sub-transmission line, and establishing distance (or directional) protection schemes at each end of this sub-transmission line. This would free up capacity at FF and its 6.6 kV feeders to accommodate other load growth in the area.

[redacted]

The scope of works includes:

- Install a new normally-closed 22 kV ACR on the BTS-FF181 line between Westfield St and Jeffrey St.
- Protection review and update on the BTS-FF 22 kV sub-transmission loop.
- Install new 0.2km 300 mm^2 Al 22 kV xlpe underground cable from east side of new ACR to FF89 overhead in Heidelberg Rd just west of isol 12794.
- Install new 1.0km 300 mm^2 Al 22 kV xlpe underground cable from west side of new ACR to the normally open auto-changeover switch within the major customer site which connects through to the existing FF89 overhead in Yarra Bend Rd
- Convert iso 12797 to open bridge. Replace all overhead and unground assets downstream of this point with 22 kV construction (approximately 1.5km).
- Convert the following 7 substations to 22 kV – Albert-Westfield, H'Berg-Yarrabend, Yarrabend-NMIT, Yarrabend-Fairfield Institute, Yarrabend-Eastern Fwy, Yarrabend-Park, Yarrabend-Fairfield Pk.

9.3.8 Reconductor BTS-FF 181

Following completion of works described in section 9.3.10, a further upgrade of this sub-transmission loop is to reconductor the BTS-FF 181 22 kV sub—transmission line. This solution will address the thermal overload limitations on this sub-transmission loop by increasing the rating of this line to 19 MVA..

The scope of work includes:

- Reconductor 5.7 km of overhead line on BTS-FF 181 with 37/3.75AAC built for 22 kV.
- Replace 0.4 km of undersized underground cable with 2 x 300 mm^2 Al 22 kV xlpe cable.

for a rating of 500 Amps.

9.3.9 FF #4 6.6 kV Bus

This solution is a committed project for 2026, providing additional feeder exits for customer connections at FF.

9.3.10 Augment BTS-FF 22 kV Loop

A RIT-D was undertaken in 2022 to reinforce 22 kV sub-transmission supplies to FF zone substation with the preferred option being to combine BTS-FF 184 and BTS-FF 188 and augment BTS-FF 22 kV loop with a 3rd 22 kV line (twin cable) by summer 2025-26. This is now a committed project[31].

[redacted]

[31] The scope of the RIT-D committed project included paralleling the sections of BTS-FF 184 and BTS-FF 188 that are in a common cable trench/shared double circuit poles (3.5km in total), by relocating the existing BTS-FF 184 cable at BTS to the BTS-FF 188 CB, and connecting the two circuits at pole 31, to form a combined BTS-FF 188 feeder. Then, reconductoring the 200 m section of BTS-FF 188 undersized overhead line between FF and pole 38 with 37/3.75AAC to increase the summer rating of BTS-FF 188 to 500A (19.0 MVA). Then, retiring the existing 0.6 km section of BTS-FF 184 overhead conductor sharing the same poles as BTS-FF 181 from pole 78 to FF, and disconnecting from the BTS-FF 184 incomer connection at FF, and installing approximately 4.1 km of new 2 x 3c 300 mm^2 Al XLPE underground cable from BTS-FF 184 feeder CB at BTS, to connect to BTS-FF 184 incomer at FF, providing a 30.5 MVA line rating. Refer to this RIT-D DPAR for further details on the need (including load forecasts) and implementation plans.

9.4 Northern Growth Corridor Cluster

9.4.1 TTS New Sub-Transmission Loop

This solution is aimed at addressing the thermal limitations on the TTS-BD-BMS-COO-VCO-TTS 66 kV meshed sub-transmission loop. The scope involves establishing two new 66 kV feeders from TTS into the southern part of the Northern Growth Corridor Cluster as shown.

[redacted]

The scope includes:

- Establishing a new TTS-DC21 No.1 feeder using a new 9 km single circuit overhead line from TTS Bay N (No.3 66 kV Bus) to a new DC21 zone substation, relocating the existing COO feeder to Bay L (No.3 66 kV Bus).

- Establishing a new TTS-DC21 No.2 feeder on a separate line route using a new 13 km overhead line (4 km on double circuit with TTS-CN, and 9 km on single circuit), from TTS Bay V (No.6 66 kV Bus) to a new DC21 zone substation.

- Establish a BD-DC21 feeder using 0.2 km of single circuit overhead line from the DC21 zone substation to a cut-in on the BD-BMS circuit on the existing double circuit pole line at the end of Merlynston Close. Establish the BMS-DC21 feeder using 0.2 km of single circuit overhead line from the DC21 zone substation to the cut-in on the BD-BMS circuit (physically separated from the BD-DC21 circuit). It is required to roll the vertical construction of both the BD-BMS and TTS-KMS circuits to horizontal (on 66 kV poles in the easement in the vicinity of the end of Merlynston Close), to allow the BD-BMS 66 kV line to be cut-in and the TTS-KMS 66 kV line to continue through unaffected.

9.4.2 ST-SSS 66 kV Line Extension

This solution is aimed at extending 66 kV supplies from ST into the northern part of the Northern Growth Corridor Cluster as shown to supply prospective major customers north of the planned CBN zone substation.

[redacted]

The scope of works include:

- Constructing a new 66 kV 37/3.75AAC 100/75^{o}C double circuit overhead line on the west side and a new single circuit on the east side of the Hume Highway from Patullos Lane to the new CBN site (5.0 km each) (CBN works).

- Construct 2 x 4km 66 kV 37/3.75AAC 100/75^{o}C single circuit lines from CBN and cut-in to CBN-SSS to 80 Kinloch Ct, Craigieburn and a new DC11 zone substation on the major customer site.

–

9.4.3 SMTS New Sub-Transmission Loop

This solution is aimed at providing new 66 kV supplies from SMTS into the northern part of the Northern Growth Corridor Cluster as shown to supply prospective major customers.

[redacted]

The scope includes:

- Establishing a new SMTS-DC20 No.1 feeder using a new 16 km single circuit overhead line from one SMTS feeder exit on No.4 66 kV Bus to a new DC20 zone substation.
- Establish a new SMTS-DC20 No.2 feeder on a separate line route using a new 17 km single circuit overhead line, from one SMTS feeder exit on No.5 66 kV Bus to the new DC20 zone substation.
- Establish a new SMTS-DC20 No.3 feeder using a new 16 km single circuit overhead line from two SMTS feeder exits by double-switching across the No.4 and the No.5 66 kV Buses.

9.4.4 TMTS New Sub-Transmission Loop

This solution is aimed at providing new 66 kV supplies from a new TMTS into the Northern Growth Corridor Cluster as shown to supply prospective major customers. For DC21, the scope includes:

- Establishing the new TTS-DC21 No.1 feeder using a new 4.0 km single circuit overhead line from TMTS feeder exit on the No.1 66 kV Bus.
- Establishing the new TTS-DC21 No.2 feeder using a new 4.0 km single circuit overhead line from TMTS feeder exit on the No.2 66 kV Bus.
- Establishing the new TTS-DC21 No.3 feeder using a new 4.0 km single circuit overhead line from TMTS feeder exit on the No.3 66 kV Bus.

[redacted]

9.4.5 DBTS New Sub-Transmission Loop

This solution is aimed at providing new 66 kV supplies from a new Donnybrook Terminal Station (DBTS) into the Northern Growth Corridor Cluster as shown to supply prospective major customers. For DC20, DC11 and DC22, the scope includes:

- Establishing a new DBTS-DC20 No.1 feeder using a new 3.0 km single circuit overhead line from DBTS feeder exit on the No.1 66 kV Bus to a new DC20 zone substation.
- Establishing a new DBTS-DC20 No.2 feeder using a new 3.0 km single circuit overhead line from DBTS feeder exit on the No.2 66 kV Bus to the new DC20 zone substation.
- Establishing a new DBTS-DC20 No.3 feeder using a new 3.0 km single circuit overhead line from DBTS feeder exit double-switched across the No.1 and the No.2 66 kV Buses to the new DC20 zone substation.

[redacted]

10. Appendix C – Scopes of Work for Customer Connection Assets

10.1 A154

Supply the A154 site in its entirety via four new 11 kV feeders from Flemington Zone Substation (FT).

[redacted]

Refer to **A154 Feasibility Study** for the scope of work. Noting since the development of this feasibility study, the ulttimate solution has been refined with two feeders from FT and two feeders from NS.

10.2 A17 & A26

Install three new 6.6 kV feeders from FF to the customer site as follows.

1st new feeder – install a new 0.8km 300 mm^2 Al xlpe 6.6 kV exit cable from a spare (or piggyback) CB on 6.6 kV Bus No.2 along McGregor St to a new CHP just south of a new normally open MGS in Fulham Rd between this feeder and FF 90. Reconductor the 0.4km overhead section with 19/3.25AAC from this location along Fulham Rd to just south of Parklands Ave, removing the droppers on the corner of Fulham and Separation St with FF 96. Install 1.0km new single circuit 6.6 kV 19/3.25AAC from Fulham Rd, placing a normally closed MGS just north of this tee-off and a normally open MGS at iso 12616 just south of this tee-off, along Nelson Rd, across the railway line and down Lowther St to a new normally open MGS on FF 95. Install new 0.2 km 300 mm^2 Al xlpe 6.6 kV underground cable from just north of this new switch across Heidelberg Rd into the customer site.

2nd new feeder – install a new 1.8km 300 mm^2 Al xlpe 6.6 kV exit cable (with a spare conduit for the whole length) from a spare (or piggyback) CB on 6.6 kV Bus No.3 along Station St, Separation St and Perry St, across the railway line) to a new CHP with a new normally closed MGS south of the corner of Grange Rd and Hamilton St on the west side of Grange Rd. Install 0.1km of 19/3.25AAC overhead line from this CHP to a new normally open MGS on FF 83 on the east side of Grange Rd. Install new 0.5 km 300 mm^2 Al xlpe 6.6 kV underground cable from this new overhead line section down Chander Hwy into the customer site.

3rd new feeder – install a new 1.8km 300 mm^2 Al xlpe 6.6 kV exit cable (within the spare conduit provided by the 2nd feeder) from a spare (or piggyback) CB on 6.6 kV Bus No.2 along Station St, Separation St and Perry St, across the railway line) to another new CHP with a new normally closed MGS south of the corner of Grange Rd and Hamilton St on the west side of Grange Rd. Install 0.2 km of 19/3.25AAC overhead line from this CHP to a new normally open MGS on FF 88 on the south side of Heidelberg Rd. Install new 0.5 km 300 mm^2 Al xlpe 6.6 kV underground cable from this new overhead line section down Chander Hwy into the customer site.

10.3 A197

Utilise the existing customer connection point.

10.4 A50

Refer to **A50 Feasibility Study** for the detailed scope of work.

10.5 A53

Establish a new EPN 22 kV Feeder of 5.0 km underground cable rated at 400A.

10.6 A54

The existing TH22 can be used as a backup for a new dedicated feeder piggyback onto TH 21 CB to supply the development. Install 1 km of 300 mm^2 Al 22 kV xlpe cable from TH to the new development. Install a tie point through to TH 22 downstream of MGS 11197.

10.7 A923

Committed project.

10.8 A997

Committed project.

10.9 TEMPA

The scope is to supply Phase 1 via ST23 by loop in and out of existing underground cables adjacent to the connection point. Transfer 4MVA load from ST24 to BD01. The scope also includes supply for Phase 2 via ST34 by extending ST34 from east of Hume Hwy to the customer site. Transfer 7MVA load from ST34 to BD13. Transfer 3MVA load from BD13 to BD08. Transfer 4 MVA load from BD13 to BD16.

10.10 TEMPB

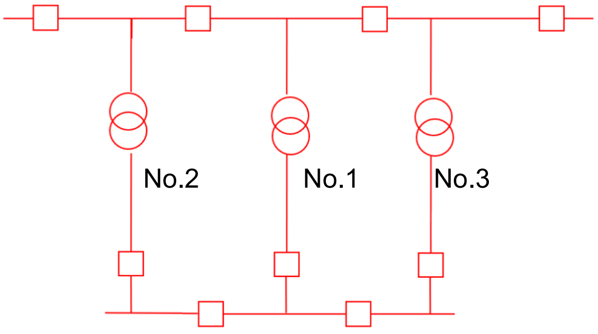
Establish a new 22 kV feeder from AW zone substation.

10.11 TEMP5

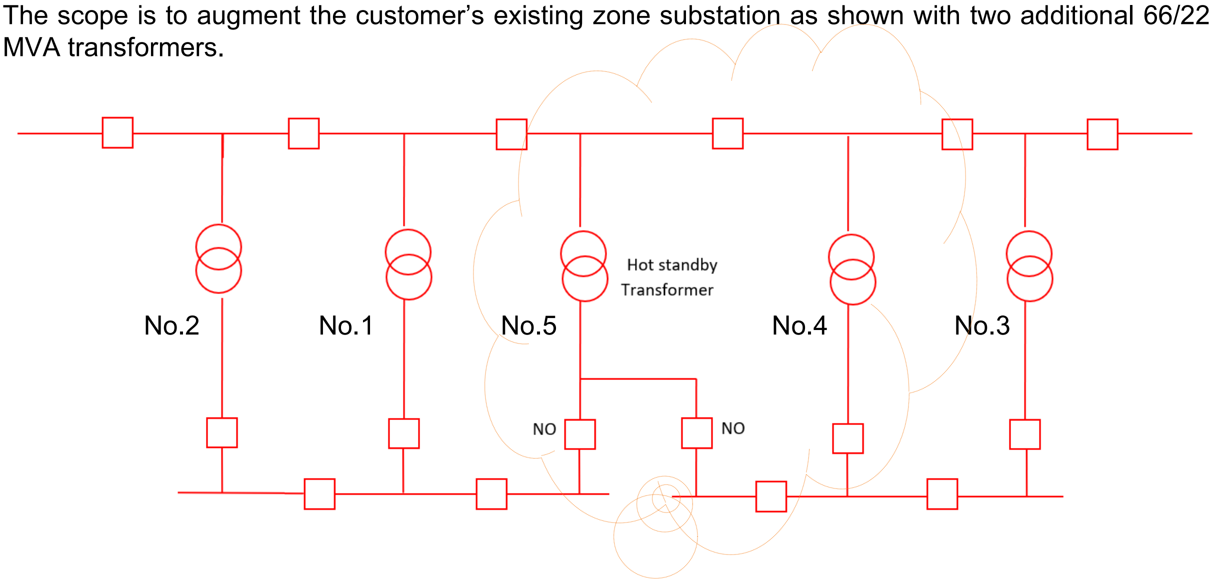
Install one new 6.6 kV feeder to the customer site from FF (2.5km U/G, 375A).

10.12 A60

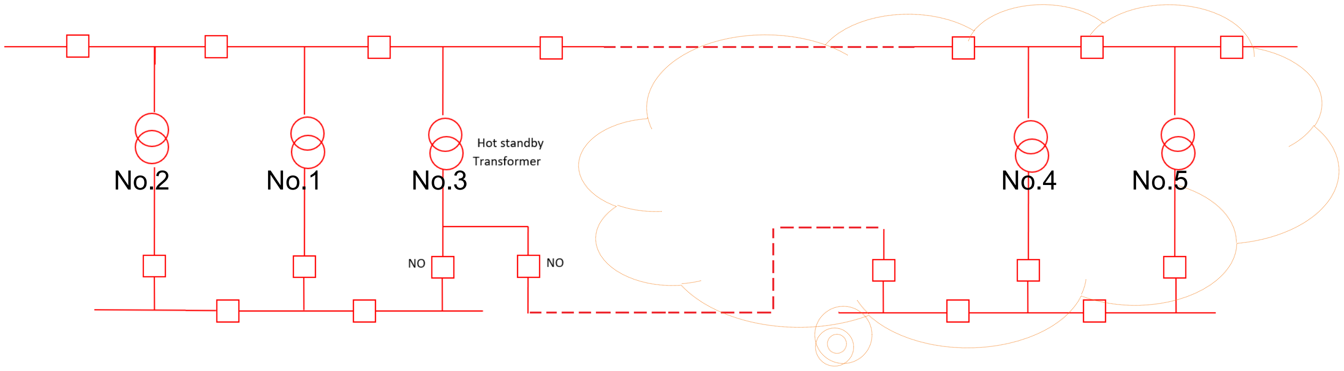
The existing arrangement at the customer zone substation is shown below.



The scope is to augment the customer's existing zone substation as shown with two additional 66/22 kV 20/33 MVA transformers.



Alternatively, establish a new zone substation adjacent to the customer's existing zone substation as shown.



10.13 DC01

Augment the customer's existing zone substation with an additional 50 MVA transformer.

For further expansion of the customer site, establish a second (identical) zone substation within the Customer's site and tie together with the existing zone substation using a set of underground 66 kV cables rated at 1250 A using the spare 66 kV line incomers to the GIS switchgear (normally closed). All buses to be rated for 2500 A.

Refer to **BAA-CBH-000123 Feasibility Study - NEXTDC 2_5** for the detailed scope of work.

10.14 DC02

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer.

Refer to **BAA-CBH-000157- DC2 NEXTDC M3 150MVA 66kV Supply - Feasibility Study** for the detailed scope of work.

10.15 DC04

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer.

Refer to following documents for the detailed scope of works.

- **DC4 MS MEL07 - SoW Part 1 of 2 – Sub-transmission and Comms Network**
- **DC4 MS MEL07 - SoW Part 2 of 2 - Substation (No 22kV Switchboards)**

10.16 DC06

Project commissioned.

10.17 DC07

Stage 1 - project to build a zone substation at Customer's site with 2x66/11 kV 20/33 MVA transformers has been completed.

Stage 2 - Install 2x66/11 kV 30/50 MVA transformers at the existing zone substation within the Customer's site.

Refer to **DC7 Brooklyn Stage 2 SOW** for detailed scope of works.

10.18 DC09

Establish a new 66 kV zone substation within the Customer's site, providing with two fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for minimum of 1,600A with 2 x 50 MVA transformers, with the ability to expand to an ultimate of three transformers. A loop of DC09 into the BLTS-TH No.2 66 kV line will be required to connect DC09 into the existing 66 kV sub-transmission network.

Refer to following documents for the detailed scope of work.

- **DC9 West Footscray - SoW Part 1 of 2 – Sub-transmission and Comms Network**
- **DC9 West Footscray - SoW Part 2 of 2 - Substation**

10.19 DC10

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer. A MAT-MDT 66 kV line extension to DC10 is required in order to connect DC10 into the existing 66 kV sub-transmission network.

Refer to following documents for the detailed scope of work.

- **DC10 Westmeadows - SoW Part 1 of 2 – Sub-transmission and Comms Network**
- **DC10 Westmeadows - SoW Part 2 of 2 - Substation**

10.20 DC11

Establish a new 66 kV zone substation within the Customer's site, providing with two fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for a minimum of 1,600 A. Install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer.

Refer to following documents for the detailed scope of work.

- **DC11 Craigieburn - SoW Part 1 of 2 – Sub-transmission and Comms Network**
- **DC11 Craigieburn - SoW Part 2 of 2 - Substation**

10.21 DC12

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 75 MVA transformers with provision for an ultimate third transformer. A loop of DC12 into the KTS-NDT 66 kV Line will be required to connect DC12 into the existing 66 kV sub-transmission network.

Refer to following documents for the detailed scope of work.

- **DC12 Tullamarine - SoW Part 1 of 2 – Sub-transmission and Comms Network**
- **DC12 Tullamarine - SoW Part 2 of 2 - Substation**

10.22 DC17

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Install 2 x 66/22 kV 75 MVA transformers. Loop in an out of the existing KTS-SHM 66 kV line. Install a new 66 kV underground cable from KTS West group to the new zone substation, connecting into the third 66 kV incomer.

Refer to DC17 Tullamarine - SoW Part 1 of 2 – Sub-transmission and Comms Network for the detailed scope of work.

10.23 DC18

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 2,500 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 75 MVA transformers with provision for an ultimate third and fourth transformer. A loop of DC18 into the TMA-MAT 66 kV line will be required to connect DC18 into the existing 66 kV sub-transmission network.

Refer to following documents for the detailed scope of work.

- **DC18 Tullamarine - SoW Part 1 of 2 – Sub-transmission and Comms Network**
- **DC18 Tullamarine - SoW Part 2 of 2 - Substation**

10.24 DC19

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 75 MVA transformers with provision for an ultimate third and fourth transformer.

Refer to **Feasibility Study - 2-8 Cawley Road Yarraville** for the detailed scope of work.

10.25 DC20

Establish a new 66 kV zone substation within the Customer's site with three fully-switched 1250 A rated 66 kV line incomers, and 66 kV buses to be rated for 2500 A. Initially install 2 x 75 MVA transformers with provision for an ultimate third and fourth transformer.

Refer to **Feasibility Study - Amaroo Park Data Centre, Craigieburn** for the detailed scope of work.

10.26 DC21

Establish a new 66 kV zone substation within the Customer's site with four fully-switched 1,250 A rated 66 kV line incomers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 75 MVA transformers with provision for an ultimate third and fourth transformer.

Refer to **1-31 Riggall St Broadmeadows - Feasibility Study 60MVA Stg1** for the detailed scope of work.

10.27 DC22

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer.

Refer to **Feasibility Study - Cadence Craigieburn Data Centre** for the detailed scope of work.

10.28 DC24

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer and fourth transformer.

This project is at **enquiry stage** and JEN is in the process of progressing with the feasibility study.

10.29 DC25

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer.

This project is at **enquiry stage** and JEN is in the process of progressing with the feasibility study.

10.30 DC26

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer.

This project is at **enquiry stage** and JEN is in the process of progressing with the feasibility study.

10.31 DC27

Establish a new 66 kV zone substation within the Customer's site, providing with three fully-switched 1,250 A rated 66 kV line incomer circuit breakers, and 66 kV buses to be rated for 2,500 A. Initially install 2 x 66/22 kV 75 MVA transformers with provision for an ultimate third transformer.

This project is at **enquiry stage** and JEN is in the process of progressing with the feasibility study.

10.32 TEMP16

Extend 22 kV feeder EPN34 by 1.7km O/H, 1025A 66 kV construction for initial supplies. Customer to install 2 x 75 MVA 66/22 kV transformers at a new zone substation within its site with the ability to expand to an ultimate of three transformers. 66 kV bus and all switchgear shall be rated for minimum of 1,600A.

Refer to **TEMP16 Feasibility Study** for the detailed scope of work.

10.33 Waste to Energy Wollert

This is a proposed new 48 MW 66 kV generation connection at 510 Summerhill Rd, Wollert. The scope of work involves looping in the power station into the existing SMTS-SSS-ST-SMTS 66 kV loop, by extending sections of this sub-transmission loop.

10.34 Hillside Solar Farm

This is a proposed new 30 MW generation connection at Kinetic Ave, Hillside. The scope of work involves a radial connection of the power station to the existing KTS-SHM 66 kV line, by teeing of this sub-transmission line or connecting directly into SHM.

Refer to **Hillside Solar Farm Feasibility Study** for the detailed scope of work.

11. Appendix E – Scopes of Work for Terminal Stations

11.1 BLTS

11.1.1 BLTS 2 x 220/66 kV 150 MVA (B2 & B4) Transformers

Ultimate Single Line Diagram

[redacted]

[redacted]

Alternative Ultimate Single Line Diagram

[redacted]

[redacted]

Ultimate General Layout

[redacted]

11.2 KTS

11.2.1 KTS 3 x 220/66 kV 225 MVA (B1, B2 & B5) & 1 x 220/66 kV 150 MVA (B6) Transformers

KTS Single Line Diagram - 220 kV & 220/66 kV Transformers

[redacted]

KTS General Layout

[redacted]

KTS Single Line Diagram - 66 kV

[redacted]

11.2.2 KTS 3 x 220/66 kV 225 MVA (B7, B8 & B9) Transformers

KTS Single Line Diagram and General Layout

[redacted]

[redacted]

KTS Single Line Diagram - 220 kV & 220/66 kV Transformers

[redacted]

11.3 SMTS

11.3.1 SMTS 2 x 220/66 kV 225 MVA (B4 & B5) Transformers

SMTS Single Line Diagram (Before and After)

[redacted] [redacted]

SMTS General Layout

[redacted]

11.3.2 SMTS 1 x 220/66 kV 225 MVA (B2) Transformer

SMTS Single Line Diagram (Before and After)

[redacted]

[redacted]

SMTS General Layout

[redacted]

11.4 TMTS

11.4.1 TMTS New Terminal Station with 2 x 220/66 kV 225 MVA (B1 & B2) Transformers

Jemena owns land at 86 Pecham St, Glenroy adjacent to a transmission line easement for the site of the future Tullamarine terminal station (TMTS).

TMTS Site Reservation

[redacted]

TMTS Single Line Diagram

[redacted]

11.5 SYTS

11.5.1 SYTS 2 x 500/220 kV 1000 MVA (A1&A2) & 2 x 220/66 kV 225 MVA (B1&B2) Transformers

SYTS Existing

[redacted]

SYTS as a 66 kV Connection Point

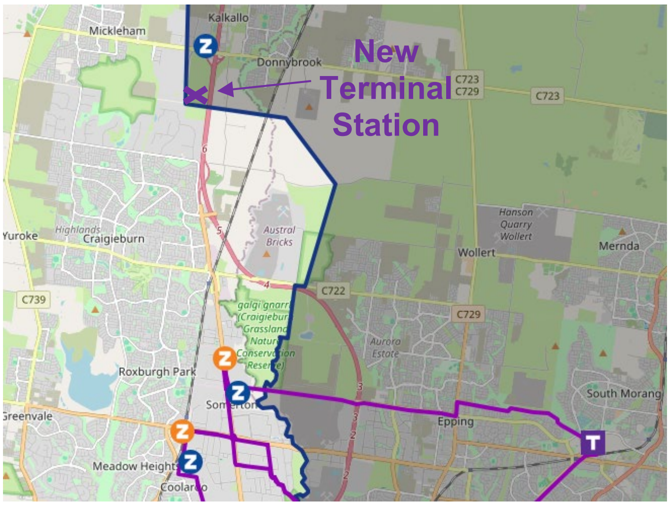
[redacted]

11.6 DBTS

11.6.1 DBTS New Terminal Station with 2 x 220/66 kV 225 MVA (B1 & B2) Transformers

AusNet owns land adjacent to the Hume Freeway just south of Donnybrook Rd and its KLO zone substation for the site of the future Donnybrook terminal station (DBTS).

DBTS Site Reservation



DBTS Single Line Diagram

[redacted]

11.7 TTS

11.7.1 TTS 1 x 220/66 kV 150 MVA (B6 – West Group, B7 – East Group) Transformer(s)

Ultimate Single Line Diagram (West Group)

[redacted]

[redacted]

Ultimate Single Line Diagram (East Group)

[redacted]

Ultimate General Layout

[redacted]

[redacted]