Jemena Electricity Networks (Vic) Ltd

Somerton Zone Substation (ST) Supply area Capacity Constraint

RIT-D Stage 2: Draft Project Assessement Report

An appropriate citation for this paper is:

Somerton Zone Substation (ST) Supply area Capacity Constraint

Executive summary

Jemena Electricity Networks (Vic) Ltd (**JEN**) is the licensed electricity distributor for the north-west 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 a reliable electricity supply at an efficient cost. To do this, we must choose the most efficient solution to address current and emerging network limitations. This means identifying the credible option that maximises the present value of the net economic benefit (the preferred option).

Identified need

Somerton (**ST**) zone substation is owned and operated by JEN, providing power to more than 19,330 customers in Melbourne's outer north. ST supplies both the residential areas of Craigieburn, Roxburgh Park, and Greenvale to the west of the Hume Highway, and a mixture of industrial and commercial load predominantly located on either side of the highway in the Somerton and Campbellfield areas. The adjacent area of Coolaroo to the west is supplied by JEN's Coolaroo (**COO**) zone substation, and the adjacent area of Mickleham to the north is supplied by AusNet's Kalkallo (**KLO**) zone substation.

ST, COO and KLO are the main sources of supply to the Northern Growth Corridor[1] of Melbourne, and all are experiencing high growth and high utilisations. The available spare capacity provided by ST and its 22 kV distribution feeders (ST 11, ST 12, ST 22, ST 32 and ST 33), including that of the adjacent feeders providing support for the area (i.e., COO23, KLO13, KLO21 and KLO22), is declining over time. As such, this will have increasing consequences for the reliability of electricity supply to JEN's customers within the supply area as demand increases.

The identified need for this RIT-D is to maintain the reliability of supply in the Somerton supply area whilst accommodating new customer connections and increasing customer demand.

RIT-D process

Distribution businesses are required to undertake the Regulatory Investment Test for Distribution (**RIT-D**) consultation process to identify the investment option that best addresses an identified need on the network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM, as well as that arising from changes in Australia's greenhouse gas emissions (the preferred option).

The RIT-D applies in circumstances where a network limitation (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $7 million[2].

For stage 1 of the RIT-D process, JEN consulted on the credibility of potential non-network and stand-alone power system (**SAPS**) options as alternatives or supplements for the network options being considered. An Options Screening Report[3] for the Somerton supply area was published to establish whether the proposed network solutions to address the need could be changed in scope or otherwise altered in response to a non-network or SAPS solution.

For stage 2 of the RIT-D process, we have now published this Draft Project Assessment Report (**DPAR**) as the total cost of the most expensive credible network option to address the identified need is greater than the trigger threshold of $14 million[2] for consultation on a DPAR. This report quantifies the reliability of supply risks associated with network capacity limitations triggered by forecast growth in maximum electricity demand within the Somerton supply area, including from the connection of major new customers. This DPAR analyses alternative credible

[1] GCP - Chapter 5 Northern Growth Corridor Plan, Victorian Planning Authority.

[2] AER 2024 RIT and APR cost thresholds review final determination (November 2024).

[3] RIT-D Stage 1: Options Screening Report, Jemena, 22 August 2024.

options for economically mitigating those risks, and identifies the preferred option at this draft stage of the RIT-D assessment.

Options considered

The Options Screening Report presented network options designed to address the identified need for continuing to reliably meet the electricity demand requirements of customers in the Somerton supply area. The credible options considered were:

- Option 1 – Base case "Do Nothing";
- Option 2 – Craigieburn zone substation (**CBN**) development plan; and
- Option 3 – Greenvale zone substation (**GVE**) development plan.

The Options Screening Report also considered the credibility of potential non-network and SAPS options as alternatives to, or supplements for the identified network options to meet the identified need, and called for submissions from potential non-network proponents. This is in the context of a non-network or SAPS option being able to supply any capacity shortfalls at ST, COO and the relevant feeders, in meeting their forecast demand during the 10-year planning horizon.

JEN received no submissions for non-network or SAPS solutions in response to the consultation on the Options Screening Report, leaving only options 1, 2 and 3 for assessment in this DPAR.

Proposed preferred option

The preferred option is that option which maximises the present value of the net economic benefit, weighted across a set of reasonable state-of-the-world scenarios. Table 1–1 below summarises the cost-benefit analysis for each option, based on the weighted outcome across the three scenarios considered.

Table 1–1: Summary of cost benefit analysis (PV, $ million, 2024), weighted outcome

Present Value	Option 1 – Do Nothing	Option 2 - CBN	Option 3 - GVE
Network capital investment	0	71.13	96.69
Additional opex (O&M)	0	4.81	5.84
Avoided expected unserved energy (EUE)	0	6,906	6,906
Net Market Benefits (NPV)	**0**	**6,830**	**6,804**

The option that has been found to maximise the present value of net market benefits, both on a weighted basis and in each scenario, is Option 2. The robustness of this conclusion has been tested under a range of sensitivities. In each case, Option 2 was confirmed to provide positive economic benefits and is the highest ranked option. Option 2 therefore satisfies the requirements of the RIT-D and is the proposed preferred option at this draft stage.

The scope of the proposed preferred option involves establishing a new 66/22 kV 2 x 20/33 MVA Craigieburn (CBN) zone substation with six new 22 kV feeders at a JEN-owned site 750 Hume Highway, Craigieburn and extending two 66 kV lines from ST to CBN along both sides of the Hume Highway (approximately 10 km in total). It also includes the establishment of a second 66/22 kV 2 x 45/75 MVA zone substation for major customer connections in Craigieburn, approximately 4 km north of CBN, and a further extension of the two 66 kV lines from CBN to connect in the proposed new customer zone substation (approximately 8 km in total).

The capital cost of Option 2 is approximately $75.46 million (real 2024). The assessment finds that the optimal completion date for the entire option is by 2025/26. However with construction time of three years, led by the new zone substation for the major customers first, followed by the new CBN zone substation to service the broader supply area, the practical timing for completion of Option 2 in full is November 2027.

Submission and next steps

We now invite written submissions on this report from interested stakeholders identified as "Somerton Supply Area RIT-D".

All submissions and enquiries should be directed to:

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

Submissions should be lodged with us within 6 weeks after the publication of this report, on or before 14 February 2025. All submissions will be published on JEN's website. If you do not wish to have your submission published, please indicate this clearly in your submission.

Following consideration of any submissions on this DPAR, JEN will proceed to prepare a Final Project Assessment Report (**FPAR**). That report will include a summary of, and commentary on, any submissions to this DPAR, and present the final preferred option to address the identified need. Publishing the FPAR will be the final stage of the RIT-D process.

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Glossary

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Contingency (or ‘N-1’ condition)	An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Energy-at-risk	The energy at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
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.
Limitation	Refers to a constraint on a network asset’s ability to transfer power.
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Jemena Electricity Networks (Vic) Ltd (JEN)	One of five licensed electricity distribution networks in Victoria, Jemena Electricity Networks (Vic) Ltd is 100% owned by Jemena and services over 370,000 customers covering north-west greater Melbourne.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt Ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network’s ability to transfer electricity to customers.
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.
Probability of Exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Distribution (RIT-D)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a prescribed limit, in the National Electricity Market (NEM).
Stand Alone Power System (SAPS)	An embedded power system that operates disconnected (islanded) from the network.
System Normal (or ‘N’ condition)	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices
Value of Customer Reliability (VCR)	Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
Zone Substation	Refers to the location of transformers, ancillary equipment and other

	supporting infrastructure that facilitate the electrical supply to a particular zone in Jemena’s Electricity Network.
10% POE condition (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 condition (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 condition (winter)	Refers to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CBN	Craigieburn Zone Substation (future)
COO	Coolaroo Zone Substation
CPI	Consumer Price Index
DAPR	Distribution Annual Planning Report
DPAR	Draft Project Assessment Report
EUE	Expected Unserved Energy
GVE	Greenvale Zone Substation (future)
FPAR	Final Project Assessment Report
HV	High Voltage
JEN	Jemena Electricity Networks (Vic) Ltd
KLO	Kalkallo Zone Substation (AusNet)
kV	Kilo-Volts
LV	Low Voltage
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System normal condition
N-1	Single contingency condition
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
O&M	Operations and Maintenance
POE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
SAPS	Stand-alone Power System
ST	Somerton Zone Substation
VCR	Value of Customer Reliability

1. Introduction

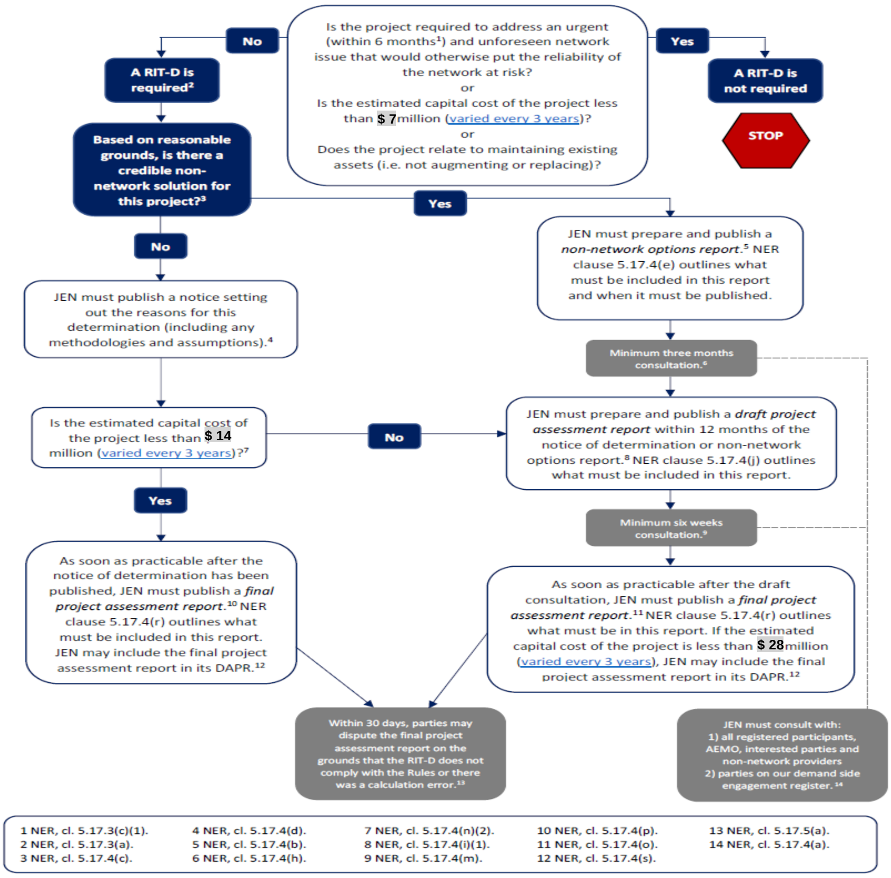
This section outlines the purpose of the Regulatory Investment Test for Distribution (**RIT-D**) in relation to the Somerton supply area, and the structure of this Draft Project Assessment Report (**DPAR**).

1.1 RIT-D purpose and process

Jemena Electricity Networks (Vic) Ltd (**JEN**), being a regulated distribution network service provider (**DNSP**), is required to undertake the RIT-D consultation process in accordance with clause 5.17 of the National Electricity Rules (**NER**), to identify the investment option that best addresses an identified need on its electricity network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**) as well as that arising from changes in Australia's greenhouse gas emissions (the preferred option).[4] The identified need in this RIT-D is to maintain the reliability of supply in the Somerton supply area, whilst accommodating new customer connections and growth in customer maximum demand.

The RIT-D applies in circumstances where a network limitation (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $7 million[5]. JEN has identified two potential credible network options. The capital cost of both of the credible options to address this identified need within the Somerton supply area is above this threshold and so has triggered the requirement for a RIT-D. The RIT-D process is summarised in Figure 1-1.

Figure 1–1: The RIT-D Process



[4] The net economic benefit is defined in the NER to include the sum of (a) the net economic benefit, other than of changes to Australia's greenhouse gas emissions, to all those who produce, consumer or transport electricity in the NEM; and (b) the net economic benefit of changes to Australia's greenhouse gas emissions, whether or not that net benefit is to those who produce, consume or transport electricity in the NEM.

[5] Source: AER 2024 RIT and APR cost thresholds review final determination (November 2024). The RIT-D also applies where the identified need is reliability corrective action.

JEN must consider non-network and stand-alone power system (**SAPS**) options when assessing credible options to address the identified need. As part of the first stage of the RIT-D process for the Somerton supply area, an options screening report was published because it was identified by JEN that a non-network or SAPS solution may be potentially viable to address the identified need. As the consultation on this options screening report has now concluded, JEN has now prepared this DPAR to commence the second stage of RIT-D consultation.

1.2 Structure of this report

The objective of this DPAR is to present the results of an economic evaluation that assesses the credible options for addressing the identified need within the Somerton supply area, and to identify the proposed preferred option.

The contents of this DPAR is set out as follows:

- Section 2 articulates the identified need in relation to the Somerton supply area;
- Section 3 sets out the key assumptions relating to the identified need;
- Section 4 provides a summary of, and commentary on, the submissions on the options screening report (noting that no submissions were received);
- Section 5 sets out the credible options assessed to address the identified need;
- Section 6 summarises the assessment method applied;
- Section 7 presents the net present value assessment results for the credible options assessed; and
- Section 8 details the technical characteristics, costs and optimal timing of the proposed preferred credible option, and next steps.

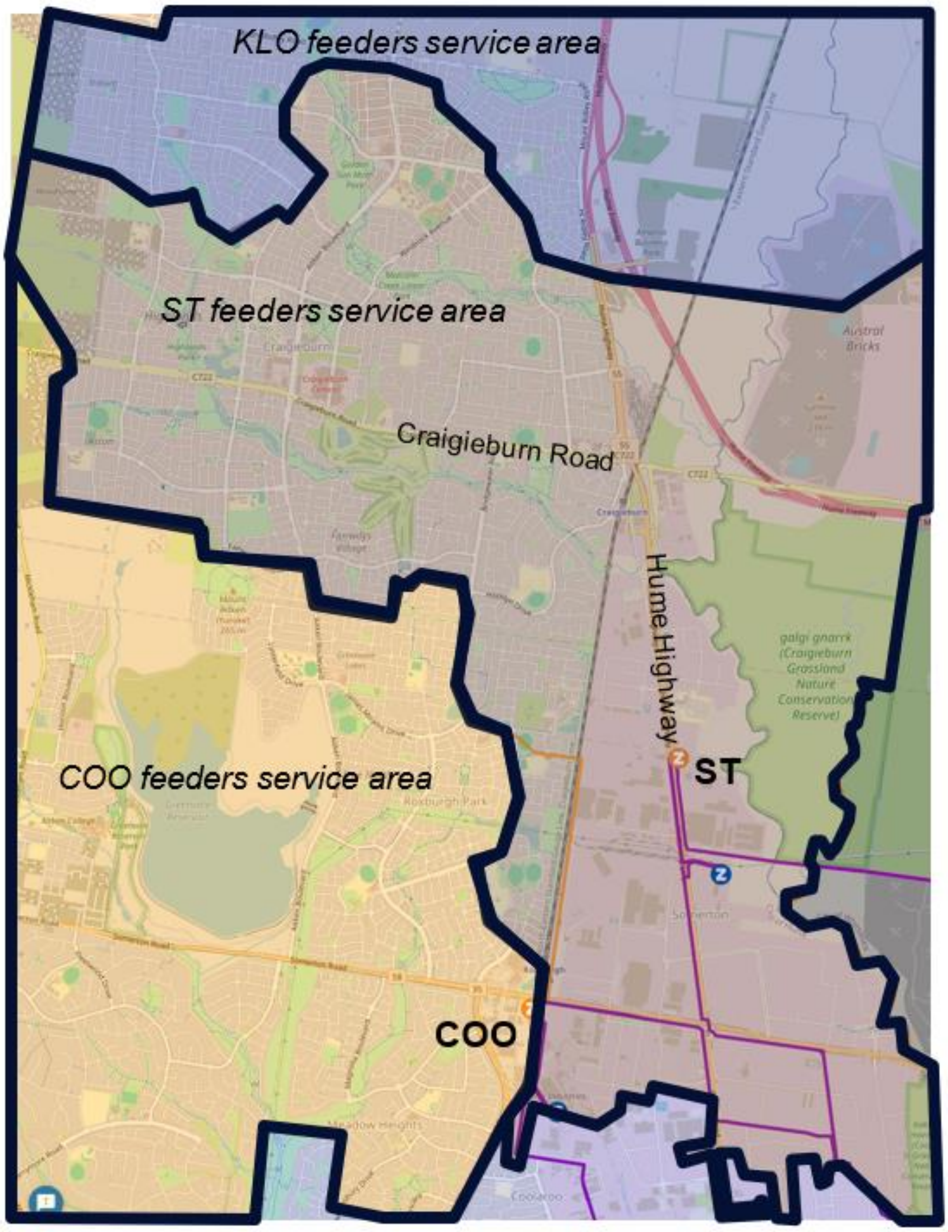
2. Identified need

This section provides an overview of the Somerton supply area, describes the general arrangement of the distribution network servicing this area, and articulates the identified need in relation to the forecast network limitations within the supply area.

2.1 Somerton supply area

Somerton (**ST**) zone substation is owned and operated by JEN, providing power to more than 19,330 JEN customers in Melbourne's outer north. ST supplies both the residential areas of Craigieburn, Roxburgh Park, and Greenvale to the west of the Hume Highway, and a mixture of industrial and commercial load predominantly located on either side of the highway in the Somerton and Campbellfield areas. The adjacent area of Coolaroo to the west is supplied by JEN's Coolaroo (**COO**) zone substation, and the area of Mickleham to the north is supplied by AusNet's Kalkallo (**KLO**) zone substation. Figure 2–1 shows the geographic extents of ST, COO and JEN's KLO feeders that service the Somerton supply area.

Figure 2–1: JEN Somerton supply area



2.2 Somerton (ST) zone substation

Lying within Melbourne's Northern Growth Corridor[6], the electricity distribution assets within the Somerton supply area are experiencing high electricity demand growth and high utilisations. The available spare capacity provided by ST and its 22 kV distribution feeders (ST 11, ST 12, ST 22, ST 32 and ST 33), including that of the adjacent feeders providing support for the area (i.e., COO23, KLO13, KLO21 and KLO22), is declining over time. This will have increasing consequences for the reliability of electricity supply to JEN's customers within the Somerton supply area over coming years, as peak demand increases.

ST consists of three 66/22 kV 20/33 MVA power transformers, and 12 x 22 kV feeders from three 22 kV indoor bus switchboards. The total system normal (N) secure rating of the zone substation is 95.2 MVA. The single contingency (N-1) rating is based on the transformer cyclic ratings, assuming one transformer is out of service. This gives an N-1 rating of 79.7 MVA (summer) and 89.3 MVA (winter). ST is currently fully built out to its ultimate configuration and cannot accommodate any new distribution feeders.

The load transfer capacity away from ST is currently 9.5 MVA, however with the high growth in the area, this level is expected to deteriorate by approximately 1 MVA per annum.

ST is a winter peaking zone substation. The ST maximum demand (prior to load transfers) is forecast to be 91.3 MVA for the winter of 2025 under a 10% Probability of Exceedance (**POE**). By 2034 it is forecast that maximum demand will rise to approximately 121 MVA. Our forecasts for underlying growth are developed by our forecasting consultant, Blunomy, and are customised for the local area. This rapid increase in the maximum demand forecast over the next several years is largely the result of some significant subdivision developments occurring in the northern part of the Somerton supply area.

In addition to the forecast underlying maximum demand increase, a number of new major customers are expected to connect to the network within the northern part of Somerton supply area (within the next two to three years), with an expected total maximum demand of 33 MVA (summer) / 28 MVA (winter) by 2034 expected to be connected upstream of ST on its sub-transmission network. Our forecasts for major customers are developed by moderating and aggregating our customers' forecasts of maximum demand using a formalised process that takes into account the likelihood of each connection (proceeding, timing and magnitude of initial and ultimate load), and the advancement of each through the connection process.

2.3 Network capacity limitations

There is forecast to be insufficient capacity to supply the forecast maximum demand at ST with the existing assets that are in place. This is likely to lead to a significant deterioration in supply reliability for customers within the Somerton supply area under system normal and single contingency conditions, and inhibit the connection of new customers. This is exacerbated by the deteriorating transfer capacity away from ST zone substation to surrounding zone substations, via the 22 kV distribution feeder ties whose spare capacity is eroding with growth in maximum demand.

The identified need for this RIT-D is to maintain the reliability of supply in the Somerton supply area whilst accommodating new customer connections, and growth in customer maximum demand. The zone substation assets limiting the summer and winter capacity at ST are the 66/22 kV power transformers' thermal limits, and of the existing 22 kV buses to support additional feeders to meet increasing demand within the Somerton supply area.

A credible solution to the identified need should seek to maintain levels of supply reliability for customers within the Somerton supply area. Hence, the solution should deliver sufficient capacity to reliably supply the demand within the supply area throughout the year, taking into account the forecast demand, available network capacity (under system normal and single contingency conditions) and load transfer capacity. The annualised cost of a credible option must be lower than the value of the expected unserved energy (EUE) that it is intending to displace.

[6] Victorian Planning Authority – The North Growth Corridor Plan.

2.4 Quantification of the identified need

The annual value of EUE associated with ST's capacity and its demand profile[7] taking into account asset ratings, probability of failure, repair time and the available transfer capacity, are presented in Table 2–1 based on a locational VCR of $50,182 per MWh.

Table 2–1: Value of EUE ($k, 2024) (central scenario)

Year	Reliability Risk (MWh)	Reliability Risk Cost ($k)
2025	41	2,064
2026	134	6,739
2027	1,397	70,093
2028	4,268	214,154
2029	8,584	430,786
2030	14,253	715,248
2031	20,228	1,015,099
2032	29,540	1,482,384
2033	42,250	2,120,213
2034	54,961	2,758,043

[7] Using an EUE weighting of 30% for the 10% PoE maximum demand, and 70% for the 50% PoE maximum demand, summer and winter, and the load duration curve for ST.

3. Assumptions relating to the identified need

In line with the purpose of the RIT-D, as outlined in clause 5.17.1 (b) of the NER, an investment to address the identified need relating to the reliability of supply risks at ST, would be expected to result in an increase in net economic benefits. This net economic benefit increase is driven by avoiding EUE (reduced involuntary load shedding) as maximum demand at ST increases. The present value of these net economic benefits has been compared to the present value of the costs of each credible option to determine the net benefit – see section 7. The ranking of options by net benefit is then used to identify the preferred option.

JEN applies a probabilistic planning method that considers the likelihood and severity of critical network conditions and outages, based on the forecast demand and associated capacity ratings, asset condition and the associated asset failure rates. The method compares the forecast cost to consumers of energy supply interruptions (e.g., when demand exceeds available capacity) against the proposed investment cost to mitigate the EUE. The annual cost to consumers is calculated by multiplying the EUE by the locational value of customer reliability (VCR). This is then compared with the annualised investment cost, to identify optimal timing.

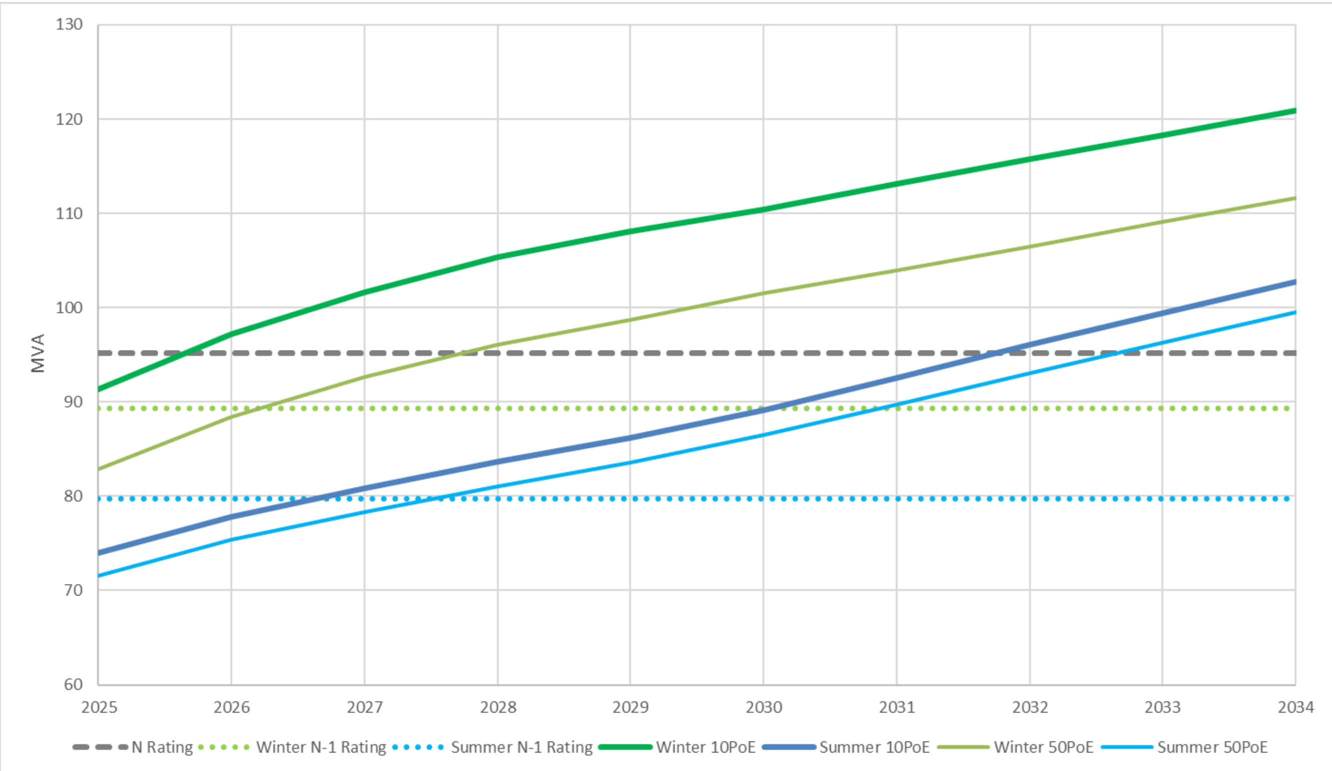
To ensure the net economic benefit is maximised, an investment will only be undertaken if the present value of benefits outweigh the present value of costs of the proposed investment to reduce the unserved energy. Investments are not always economically feasible and this planning method therefore carries an inherent risk of not being able to fully supply demand under some possible (but rare) events, such as a network outage coinciding with peak demand periods. The probabilistic planning method that we apply is further detailed in our Distribution Annual Planning Report (**DAPR**).

The key assumptions that have been applied in quantifying the Somerton supply area limitations for this DPAR are outlined in this section.

3.1 Demand forecasts

The maximum demand forecasts and capacity ratings for ST are shown in Figure 3–1.

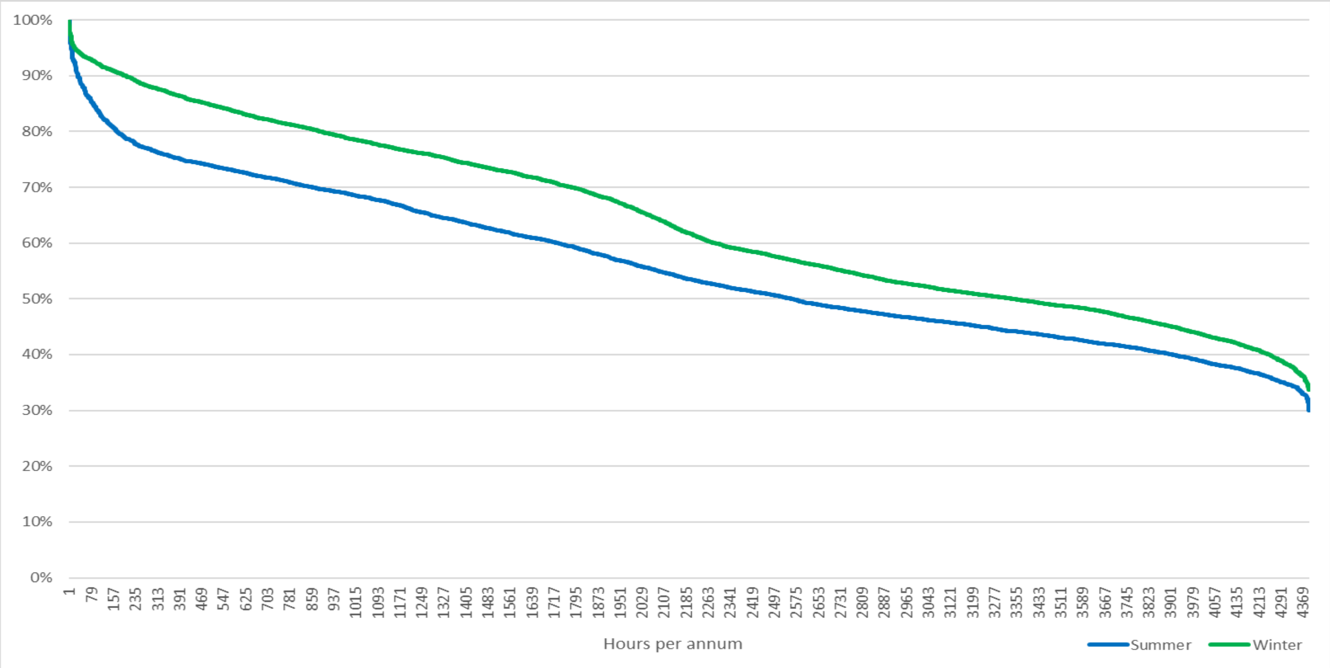
Figure 3–1: ST maximum demand forecast and ratings (MVA)



ST is expected to exceed its N rating by 2026 for a 10% PoE winter maximum demand, and 2028 for a 50% PoE winter maximum demand. The N rating is expected to be exceeded in summer from 2032. ST is already exceeding its N-1 rating for a 10% PoE winter maximum demand, and is expected to exceed its N-1 rating by 2027 for a 50% PoE winter maximum demand and a 10% PoE summer maximum demand.

The duration of the demand experienced at ST is illustrated in Figure 3–2 with a summer load factor[8] of 0.56 and a winter load factor of 0.64.

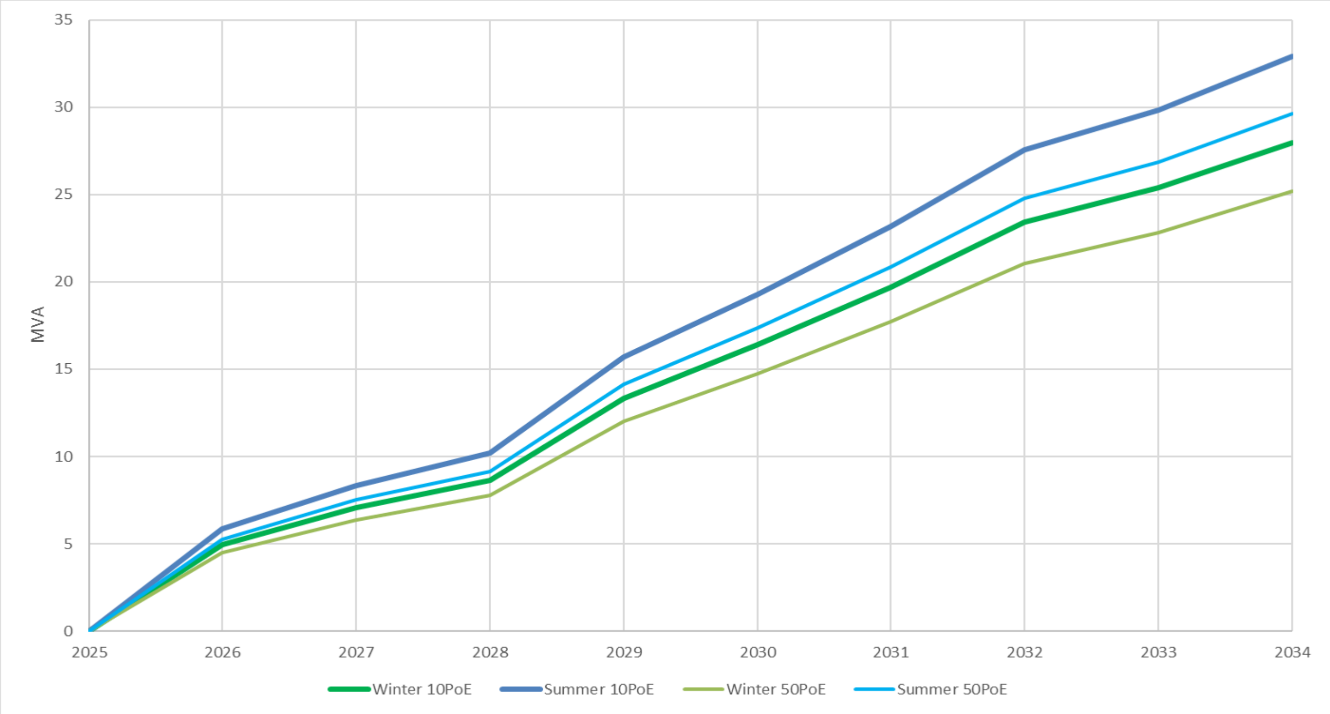
Figure 3–2: ST load-duration curve (% of summer and winter maximum demand)



The maximum demand forecasts for the new major customer connections within the Somerton supply area are shown in Figure 3–3.

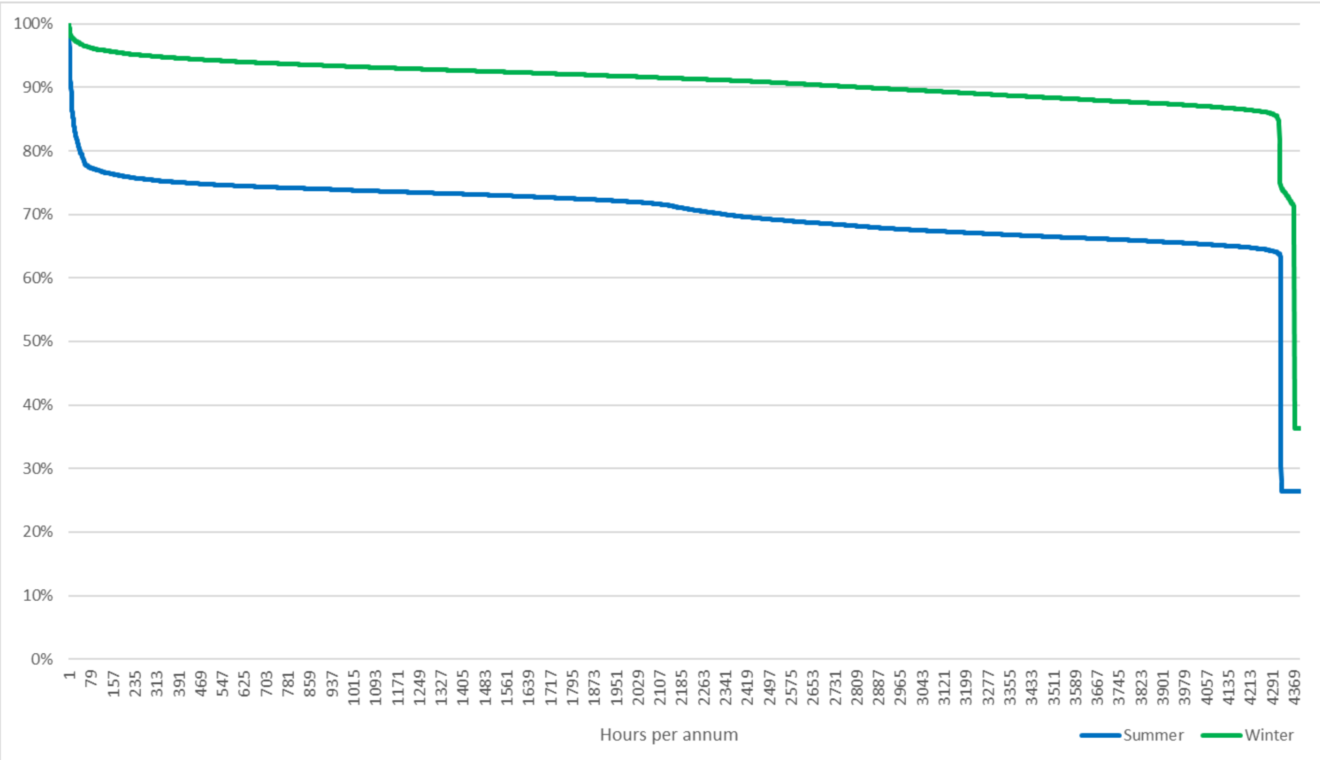
[8] Load factor is the average demand divided by maximum demand.

Figure 3–3: Major customer maximum demand forecast (MVA)



The duration of the demand experienced is illustrated in Figure 3–4 with a summer load factor of 0.70 and a winter load factor of 0.90.

Figure 3–4: Major customer load-duration curve (% of summer and winter maximum demand)



Currently there is no HV-connected embedded generation supplied from ST zone substation other than the small LV-connected residential and commercial solar PV. For ST, there are approximately 7,600 solar PV installations with a capacity of 38 MW, a penetration of 39% of customers.

3.2 Network ratings

The zone substation assets limiting the summer and winter capacity at ST are the 66/22 kV power transformers' thermal limits, and of the existing 22 kV buses to support additional feeders to meet increasing demand within the Somerton supply area.

ST consists of three 66/22 kV 20/33 MVA power transformers, and 12 x 22 kV feeders from three 22 kV indoor bus switchboards. The total system normal (N) secure rating of the zone substation is 95.2 MVA. The single contingency (N-1) rating is based on the transformer cyclic ratings, assuming one transformer is out of service. This gives an N-1 rating of 79.7 MVA (summer) and 89.3 MVA (winter). ST is currently fully built out to its ultimate configuration.

3.3 Load transfer capacity

The load transfer capacity away from ST is currently 9.5 MVA, however with the high growth in the area, this level is expected to deteriorate by approximately 1 MVA per annum.

3.4 Network asset failure rates

The following failure rates and repair times have been assumed for this RIT-D:

- Average feeder outage rate is calculated based on recent years of JEN's actual historic reliability data;
- Sub-transmission line outage frequency, which is 0.09 outages per kilometre of line length per year;
- Sub-transmission line outage average duration of 4 hours per outage;
- Power transformer outage frequency, which is 0.01 outages per year;
- Power transformer outage average duration of 2.65 months per outage.

4. Submissions on the options screening report

This section summarises the consultation to date and the submissions received on the options screening report.

A RIT-D stage 1 consultation options screening report was published on JEN's website on 22 August 2024. This report was prepared to present the potential credible options being considered and establish whether the proposed network solutions to address the need, could be changed in scope or otherwise altered in response to a non-network or SAPS solution. It was concluded from the analysis presented in that report that there could be a potential credible non-network or SAPS option (or any combination of those options, or with a network option) that could address the identified need within the Somerton supply area.

Notwithstanding this analysis, JEN did not receive any submissions, nor any proposals for alternative non-network or SAPS solutions, during the stage 1 consultation period.

5. Options considered in the RIT-D

This section outlines the credible options that have been considered in the RIT-D, and outlines the proposed works associated with each credible option. The base case is established, to compare the net benefits of options identified.

JEN has identified two network options (in addition to the base case) that attempt to address the identified need:

- Option 1 - Base case "Do nothing", i.e., shed customer load when the network is overloaded;
- Option 2 – New 66/22 kV 2 x 20/33 MVA Craigieburn (CBN) zone substation with six new 22 kV feeders;
- Option 3 – New 66/22 kV 2 x 20/33 MVA Greenvale (GVE) zone substation with five new 22 kV feeders.

Each network option also includes the establishment of second 66/22 kV 2 x 45/75 MVA zone substation in Craigieburn, and an extension of the existing ST 66 kV sub-transmission network to connect in this proposed new zone substation, to support the projected load growth from the new major customers.

5.1 Option 1 - "Do nothing" option (base case)

The assessment of credible options is based on a cost-benefit analysis that considers the future EUE reliability of supply risk cost of each credible option compared with the base case, where no additional investment is implemented.

The base case is presented as a do-nothing option (Option 1), where JEN would enact involuntary load shedding which may arise if the network is at risk of being overloaded.

5.2 Option 2 - Craigieburn (CBN) development plan

Option 2 involves establishing a new 66/22 kV 2 x 20/33 MVA Craigieburn (CBN) zone substation with six new 22 kV feeders at a JEN-owned site (750 Hume Highway, Craigieburn) and extending two 66 kV lines from ST to CBN along both sides of the Hume Highway (approximately 10 km in total).

It also includes the establishment of a second 66/22 kV 2 x 45/75 MVA zone substation approximately 4 km north of CBN for major customer connections and a further extension of the two 66 kV lines from CBN to connect the second zone substation (approximately 8 km in total).

This option is expected to deliver a substantially lower value of EUE compared to Option 1 (the base case) as it is developed to address the identified need in its entirety.

The capital cost of Option 2 is approximately $75.46 million (real 2024) including:

- $9.34 million (real 2024) for 10 km extension of the 66 kV sub-transmission network to the future CBN zone substation (stage 1);
- $4.80 million (real 2024) for a further 8 km extension of the 66 kV sub-transmission network to the new major customers zone substation (stage 1);
- $21.12 million[9] (real 2024) for establishment of the major customers zone substation (stage 1);
- $34.20 million (real 2024) for establishment of CBN (stage 2);
- $4.00 million (real 2024) for the cost of CBN land procurement[10]; and

[9] This cost excludes customer contributions.

[10] Current market valuation of existing land parcel is approximately $4.00 million (original cost to procure being $1.55 million in 2014)..

- $2.00 million (real 2024)[11] for the cost of establishing CBN land services and access.

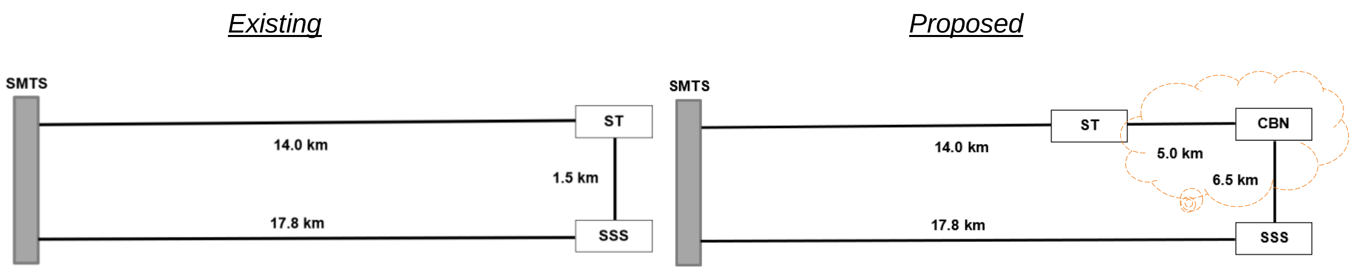
Operating costs are expected to be approximately one per cent of capital expenditure for all components other than land procurement, services and access, i.e., $0.76m p.a.

Table 5-1 sets out the construction time and earliest possible commissioning date for each of the capital cost components listed above.

Table 5-1: Construction time and earliest possible commissioning for Option 2

Component	Construction time	Earliest possible commissioning date
Stage 1	2 years	2026-27
Stage 2	3 years	2027-28

Figure 5–1: Proposed sub-transmission re-arrangement for new CBN zone substation



5.3 Option 3 - Greenvale (GVE) development plan

Option 3 involves establishing a new 66/22 kV 2 x 20/33 MVA Greenvale (GVE) zone substation with five new 22 kV feeders at a site yet to be procured in Yuroke or Greenvale, and extending two 66 kV lines from ST to GVE on separate routes (approximately 20 km in total).

It also includes the establishment of a second 66/22 kV 2 x 45/75 MVA zone substation for major customer connections and an extension of two 66 kV lines from ST along both sides of the Hume Highway to connect the second zone substation.

This option is expected to deliver a substantially lower value of EUE compared to Option 1 (the base case) as it is developed to address the identified need in its entirety. The expected reduction of EUE is nearly identical under Option 3 as for Option 2.

The capital cost of Option 3 is approximately $105.9 million (real 2024) including:

- $14.14 million (real 2024) for 18 km extension of the 66 kV sub-transmission network to the major customers zone substation (stage 1);

[11] $1.57 million cost already incurred in 2016. 1.27 multiple to real 2024 = $2.00 million.

- $21.12 million[12] for establishment of the major customers zone substation (stage 1);
- $5.00 million (real 2024) for the costs of GVE land procurement, services and access (stage 1);
- $29.34 million (real 2024) for 20 km extension of the 66 kV sub-transmission network to the new GVE zone substation (stage 2); and
- $36.30 million (real 2024) for establishment of GVE (stage 2).

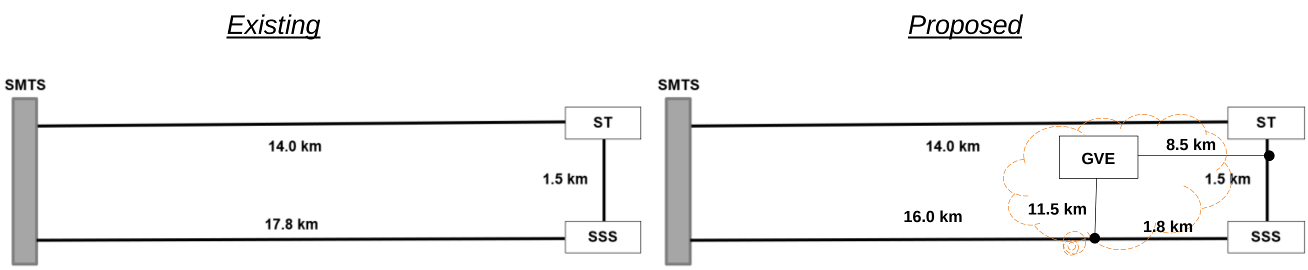
Operating costs are expected to be approximately one per cent of capital expenditure for all components other than land procurement, services and access, i.e., $1.06 million pa.

Table 5-2 sets out the construction time and earliest possible commissioning for each of the capital cost components listed above.

Table 5-2: Construction time and earliest possible commissioning for Option 3

Component	Construction time	Earliest possible commissioning
Stage 1	2 years	2026-27
Stage 2	4 years	2027-28

Figure 5–2: Proposed sub-transmission re-arrangement for new GVE zone substation



[12] This cost excludes customer contributions.

6. Assessment methodology

This section outlines the key parameters used in the economic assessment and the methodology that JEN has applied in assessing the market benefits associated with each of the credible options considered in this RIT-D. It describes how the classes of market benefits have been quantified and outlines why particular classes of market benefits are considered not material to the outcome of this RIT-D. It also describes the sensitivities applied and the reasonable scenarios considered in comparing the base case 'state of the world' to the credible options.

6.1 Key parameters

6.1.1 Discount rate

We use a regulatory discount rate to express future costs and benefits in present value terms for the central scenario, being 5.18%. For the high scenario we use AEMO's IASR assumption for a commercial discount rate of 7.0%. For the low scenario we use our 2.45% pre-tax real WACC.

6.1.2 Value of customer reliability

Location-specific VCR is used to value the EUE representing the deterioration in supply reliability. The locational VCR for the Somerton supply area was derived from the sector VCR estimates provided by the AER, weighted in accordance with the composition of the load, by sector, and escalated by CPI. The base assumption VCR used in this RIT-D is $50,182 per MWh.

Table 6-1: Load weighted VCR calculation

Parameter	Residential	Commercial	Industrial
Somerton supply area load composition	22%	49%	29%
AER VCR (Dec 202)	$23.84/kWh	$49.54/kWh	$70.98/kWh
Load weighted VCR	$50.18/kWh		
Load weighted VCR (MWh)	$50,182/MWh		

6.1.3 Assessment period

This RIT-D analysis has been undertaken over a ten-year period, from 2024-25 to 2033-34. We consider that the length of this assessment period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. The assessment period accounts for expected demand growth in the Somerton supply area intended to be addressed by the credible options in this RIT-D.

6.2 Approach to estimating option costs

The costs for each option have been calculated by our cost estimation team based on recent similar project costs and scope. Costs are expected to be within +/-30% of the actual cost.

The costs presented in this RIT-D are fully loaded including escalations, overheads and management reserve. Ongoing operating and maintenance costs are included in the assessment annually from the year after the capital investment.

Land procurement cost is based on estimated market valuation of potential (or existing held) properties in the supply area, plus costs for establishing services and site access.

Where capital components have asset lives greater than ten years, we have adopted a residual value approach to incorporating capital costs in the assessment, which ensures that the capital costs of long-lived options are appropriately captured in the ten-year assessment period.

All cost estimates are prepared in real 2024 dollars based on the information available at the time of preparing this DPAR.

6.3 Market benefit classes quantified for this RIT-D

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

The class of market benefit quantified for this RIT-D include changes in

- involuntary load shedding and customer interruption; and
- load transfer capacity.

6.3.1 Involuntary load shedding and customer interruptions

Involuntary load shedding is where a customer's load is interrupted (switched off or disconnected) from the network without their agreement or prior warning. Involuntary load shedding can occur unexpectedly due to a network outage event, or pre-emptively to maintain network loading to within asset capabilities. The aim of implementing a credible option for the options considered in this DPAR, is to reduce the amount of involuntary load shedding expected.

A reduction in involuntary load shedding, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed. The avoided involuntary load shedding benefits of a credible option are estimated by multiplying:

- The quantity (in MWh) of involuntary load shedding avoided assuming the credible option is in place; and
- The value of customer reliability (VCR) (in $/MWh).

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

JEN has adopted the AER's estimate of VCR in quantifying the value of the reduction in EUE.

JEN has captured the reduction in involuntary load shedding as a market benefit of the credible options assessed in this RIT-D.

6.3.2 Load transfer capacity

The Somerton supply area has a limited level of load transfer capacity to adjacent supply areas that can reduce the reliability impacts of an asset failure at ST and this is therefore considered to be relevant with respect to differentiating between options that provide different levels of transfer capacity.

JEN has captured the changes in load transfer capacity as a part of the involuntary load shedding market benefit in this RIT-D.

6.4 Market benefit classes not relevant to this RIT-D

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

- embedded generation;
- voluntary load curtailment;
- timing of expenditure;
- costs to other parties;
- electrical energy losses;
- option value; and
- greenhouse gas emissions.

6.4.1 Embedded generation

JEN has assessed the potential for customers to use grid-connected, standby and standalone generation and/or storage solutions in the Somerton supply area as part of our options screening report. This assessment showed there was potential for generation or storage to materially address the need, however JEN received no market responses for embedded generation or storage solutions as part of the stage 1 RIT-D consultation process. This market benefit is therefore not relevant to this RIT-D.

6.4.2 Voluntary load curtailment

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

JEN has assessed the potential for voluntary load curtailment in the Somerton supply area. The options screening report concluded that there was potential for voluntary load curtailment to provide sufficient additional capacity to either replace a network solution or to enable a more economic network solution. Nevertheless, JEN received no market responses for demand response solutions as part of the stage 1 RIT-D consultation process. This market benefit is therefore not relevant to the credible options considered in this DPAR.

6.4.3 Timing of expenditure

JEN has assessed the timing of other unrelated expenditure is not impacted by the options considered in this assessment. Therefore, this market benefit was not quantified as it was not considered to be relevant with respect to differentiating between options that address the identified need in the Somerton supply area.

6.4.4 Cost to other parties

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

6.4.5 Electrical energy losses

Reducing network utilisation, through network impedance or load changes in the ST supply area could result in a change in network losses. The network options are, however, are all expected to only marginally reduce network losses and both to a similar degree.

The consideration of electrical energy losses would not change the rankings of the options. Therefore, the market benefits associated with electrical energy losses are considered immaterial to the result of this RIT-D and have therefore been excluded from the market benefit assessments.

6.4.6 Option value

Given the absence of identified credible network or non-network deferral options, and the size of the expected growth within the supply area, it is considered that in this case, there is no potential value in retaining flexibility. JEN has therefore not attempted to identify options that would provide flexibility and estimate any additional option value market benefit for this RIT-D assessment.

6.4.7 Greenhouse gas emissions

The credible options are not expected to create any material difference in Australia's greenhouse gas emissions. The rationale for there being no impact on greenhouse gas emissions is that the options are not expected to have an impact on wholesale market generation dispatch or levels of SF_6 emissions from high-voltage switchgear.

6.5 Sensitivities

JEN has critically assessed the assumptions and parameters, and determined that the key variables affecting the estimation of net economic benefits in this RIT-D are:

- maximum demand growth rate;
- value of customer reliability (VCR);
- capital costs;
- discount rate; and
- asset failure rate.

To test the robustness of the cost-benefit analysis to changes in key variables from the base case, the following sensitivities (which vary these assumptions one at a time) have been tested as shown in Table 6–2.

Table 6–2: Sensitivity assumptions

Sensitivity	Lower bound	Base Case	Higher bound
Maximum demand forecast	90%	100%	105%
Value of customer reliability	70%	100%	130%
Capital cost	70%	100%	130%
Discount rate	2.45%	5.18%	7.00%
Asset failure rate	85%	100%	115%

6.6 State of the world scenarios

RIT-D assessments are required to be undertaken using cost-benefit analysis that includes an assessment of 'reasonable scenarios', which are designed to take into account the uncertainty associated with different future states of the world when identifying the preferred option. Weighting of the net benefit outcomes across the different scenarios is used to manage the risk associated with the uncertainty of future benefits.

The key assumptions in the analysis that have a relatively high uncertainty in the future are maximum demand and the asset failure rate, which together determine the quantity (MWh) of the EUE.

JEN has therefore adopted three future state-of-the-world scenarios, which each adopt different and consistent assumptions in relation to these two key variables :

- Low demand and failure rate scenario – credible lower bound changes to key assumptions (i.e., demand forecast and asset failure rate).
- Central scenario – the central demand forecast and central asset failure rate.
- High demand and failure rate scenario – credible higher bound changes to key assumptions (i.e., demand forecast and asset failure rate).

The table below summarises the assumptions that have been adopted under each of these scenarios, and the scenario weightings.

Table 6-3: Scenarios

Scenario	Low Scenario	Central Scenario	High Scenario
Weighting	**25%**	**50%**	**25%**
Maximum Demand	90%	100%	105%
Asset Failure Rate	85%	100%	115%

7. Options analysis

This section presents the base case and summarises the results of the NPV analysis for the two credible options. The net economic benefit analysis has taken account of the EUE risk and expected option costs over the analysis period.

Each credible option has been ranked according to its net economic benefit, being the difference between the market benefit and the costs within the assessment period (present value), compared to outcomes in the base case, and weighted across the three scenarios considered.

7.1 Option 1 – Do nothing (base case)

Option 1 involves maintaining the current operating regime. The capital cost of this option is assumed to be zero, with the cost of unplanned outages due to network asset overload represented by the value of EUE.

Table 7-1: Do nothing – present value of EUE ($M, 2024)

Option 1	Low Scenario	Central Scenario	High Scenario	Weighted Total
EUE Risk Cost	2,053	7,403	10,772	**6,908**

7.2 Option 2 – Craigieburn (CBN) development plan

The table below sets out the gross market benefits under Option 2 (i.e., the EUE risk cost that is avoided relative to Option 1 (the base case)), the total costs of Option 2 and the net market benefit, all in PV terms, in each scenario and on a weighted basis.

Table 7-2: Option 2 – present value of net economic benefits ($M, 2024)

Option 2	Low Scenario	Central Scenario	High Scenario	Weighted Total
Gross Market Benefit	2,051	7,401	10,770	**6,906**
Total option costs	75.9	75.9	75.9	75.9
Net Market Benefit	1,975	7,325	10,694	**6,830**

7.3 Option 3 – Greenvale (GVE) development plan

The table below sets out the gross market benefits under Option 3 (i.e., the EUE risk cost that is avoided relative to Option 1 (the base case)), the total costs of Option 3 and the net market benefit, all in PV terms, in each scenario and on a weighted basis.

Table 7-3: Option 3 – net present value of economic benefits ($M, 2024)

Option 3	Low Scenario	Central Scenario	High Scenario	Weighted Total
Gross Market Benefit	2,051	7,401	10,770	**6,906**
Costs	102.5	102.5	102.5	102.5
Net Market Benefit	1,949	7,299	10,668	**6,804**

7.4 Net economic benefits

The economic analysis shown in Table 7–4, based on the scenario weightings, demonstrates that Option 2 is expected to provide the highest present value of net economic benefits and is therefore the preferred option at this draft stage.

Table 7–4: Cost-benefit analysis (PV, $M, 2024) – weighted across scenarios

Option	Present value of capital and O&M	Present value of gross benefits	Present Value of Net Benefits (NPV)	Ranking
Option 1 – Do nothing (base case)	0	0	0	3
Option 2 – Craigieburn (CBN) development plan	75.9	6,906	6,830	1
Option 3 – Greenvale (GVE) development plan	102.5	6,906	6,804	2

Both of the network options considered demonstrate substantial, positive net benefits compared with Option 1 (base case), in which no investment is undertaken.

7.5 Sensitivity analysis

Two sets of sensitivities were defined in section 6.5 to test the robustness of the option rankings under the NPV assessment to changes in key assumptions. The focus of the sensitivity testing in on the central scenario, and the sensitivity analysis has tested changes in the assumptions one at a time.

The sensitivity analysis demonstrates that the conclusion that Option 2 is the preferred option is not sensitive to the changes in assumptions tested, as the ranking of the options remains constant, as shown in Table 7-5 and Table 7–6 below.

Table 7-5: Net economic benefits (PV, $M, 2024) – lower bound sensitivity for each assumption (central scenario)

Sensitivity	Option 2	Option 3	Ranking
Nil	**7,325**	**7,299**	**Option 2**
Maximum demand forecast	2,346	2,317	Option 2
Value of customer reliability	5,105	5,078	Option 2
Capital cost	7,348	7,329	Option 2
Discount rate	9,263	9,234	Option 2
Asset failure rate	6,215	6,189	Option 2

Table 7–6: Net economic benefits (PV, $M, 2024) – higher bound sensitivity for each assumption (central scenario)

Sensitivity	Option 2	Option 3	Ranking
Nil	**7,325**	**7,299**	**Option 2**
Maximum demand forecast	9,290	9,264	Option 2
Value of customer reliability	9,545	9,519	Option 2
Capital cost	7,302	7,268	Option 2
Discount rate	6,302	6,278	Option 2
Asset failure rate	8,436	8,410	Option 2

As a threshold test, we have identified what the increase in capex cost would need to be for Option 2 to make it no longer rank above Option 3. This value is $105.9 million (i.e., 140% higher). This is not considered credible.

7.6 Proposed preferred option optimal timing

The optimal timing of the proposed preferred Option 2 occurs when its annualised cost exceeds the combined annual cost of the avoided EUE of Option 1 (do nothing).

The annualised cost of Option 2 is approximately $4.9 million per annum. This is exceeded by the cost of the avoided EUE in 2025-26 under the weighted scenario as shown in Table 7–7.

Table 7–7: Annualised cost of EUE risk minus annualised investment costs ($k, 2024)

Scenario	2025	2026	2027	2028	2029	Optimal Timing
Weighted	**(1,694)**	**18,858**	**92,296**	**226,703**	**417,796**	**2025/26**
Central	(2,599)	2,076	65,429	209,491	426,122	2026/27
Low	(4,663)	(4,663)	(3,288)	(2,909)	1,065	2028/29
High	3,087	75,943	241,614	490,740	817,872	2025/26

The optimal completion date for the entire option is by 2025/26, however with construction time of three years, led by the new zone substation for the major customers first, followed by the new CBN zone substation to service the broader supply area, the practical timing for completion of Option 2 in full is November 2027.

8. Conclusion and next steps

This section summarises the proposed preferred option identified from the cost-benefit analysis at this draft stage and details next steps in the RIT-D process.

8.1 Proposed preferred option

As summarised in Table 8–1, the proposed preferred option is Option 2 as it is the credible option that maximises the present value of net market benefits. Option 2 satisfies the requirements of the RIT-D.

Table 8–1: Summary of cost benefit analysis (PV, $ million, 2024)

Present Value	Option 1 – Do Nothing	Option 2 - CBN	Option 3 - GVE
Network capital investment	0	71.13	96.69
Additional opex (O&M)	0	4.81	5.84
Avoided expected unserved energy (EUE)	0	6,906	6,906
Net Market Benefits (NPV)	**0**	**6,830**	**6,804**

Option 2 involves establishing a new 66/22 kV 2 x 20/33 MVA Craigieburn (CBN) zone substation with six new 22 kV feeders at a JEN-owned site 750 Hume Highway, Craigieburn and extending two 66 kV lines from ST to CBN along both sides of the Hume Highway (approximately 10 km in total).

It also includes the establishment of a new 66/22 kV 2 x 45/75 MVA for the major customers in Craigieburn, and a further extension of the two 66 kV from CBN to connect in the proposed new customers zone substation (approximately 8 km in total).

The proposed preferred option has a total capital cost of $75.46 million (real 2024), and is expected to incur additional annual opex of $0.76m. The RIT-D assessment has demonstrated that it is expected to provide a net economic benefit of $6,830 million (PV, 2024), over a ten-year period.

The analysis has found that the optimal completion date for the entire option is by 2025/26. However with construction time of three years, led by the new zone substation for the major customers first, followed by the new CBN zone substation to service the broader supply area, the practical timing for completion of Option 2 in full is November 2027.

8.2 Next steps

JEN invites written submissions on this report from interested stakeholders. All submissions and enquiries should be directed to:

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

Submissions should be lodged with us on or before 14 February 2025.

All submissions will be published on JEN's website. If you do not wish to have your submission published, please indicate this clearly.

Following consideration of any submissions on this DPAR, JEN will proceed to prepare a Final Project Assessment Report (**FPAR**). That report will include a summary of, and commentary on, any submissions to this DPAR, and present the final preferred option to address the identified need. Publishing the FPAR will the final stage of the RIT-D process.

9. Appendix A – Checklist of compliance clauses

Table 9–1 presents a checklist of the NER (version 220) clause 5.17.4 (j) and references the section within this DPAR where those clauses are addressed.

Table 9–1: Compliance clauses checklist

Clause	Section
(1) a description of the identified need for the investment;	2
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);	3
(3) if applicable, a summary of, and commentary on, the submissions on the options screening report;	4
(4) a description of each credible option assessed;	5
(7) a detailed description of the methodologies used in quantifying each class of cost and market benefit;	6.3 & 6.2
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;	6.4
(5) where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;	7
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	5 & 7
(9) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7.4
(10) the identification of the proposed preferred option;	8.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) the indicative capital and operating cost (where relevant); (iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent; and	8.1
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed	8.2