Jemena Electricity Networks (Vic) Ltd

Somerton Zone Substation (ST) Supply area Capacity Constraint

RIT-D Stage 3: Final 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 23,820 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 on 22 August 2024 for consultation. The analysis concluded that there may be a credible non-network or SAPS option (or a combination of such options, including with a network option) that could address the identified need within the Somerton supply area.

For stage 2 of the RIT-D process, we published a Draft Project Assessment Report (**DPAR**)[4] 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] The report quantified 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

[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.

[4] RIT-D Stage 2: Draft Project Assessment Report, Jemena, 18 December 2024.

connection of major new customers. The DPAR analysed alternative credible options for economically mitigating those risks, and identified the proposed preferred option based on a cost-benefit analysis.

JEN did not receive any submissions, nor any proposals for alternative non-network or SAPS solutions, during the RIT-D stage 1 and 2 consultations.

For stage 3 of the RIT-D process, we have now published this Final Project Assessment Report (**FPAR**) as the total cost of the preferred option to address the identified need is greater than the trigger threshold of $28 million[2] for publication of a FPAR. This report updates any changes from and submissions to the DPAR, and confirms the preferred option.

Options considered

In the absence of a credible non-network or SAPS solutions being identified from the Options Screening Report consultation, the DPAR presented for consultation, the results of an economic cost-benefit analysis of 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 assessed were:

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

JEN received no submissions in response to the consultation on the DPAR.

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	8,577	8,246
Net Market Benefits (NPV)	**0**	**8,501**	**8,144**

Option 2 is the preferred option. It maximises the present value of net market benefits, both on a weighted basis and in each scenario. The sensitivity analysis also demonstrates that Option 2 is robust to changes in assumptions tested and its ranking remains unchanged. Option 2 therefore satisfies the requirements of the RIT-D.

The scope of the 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 a construction time of two 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 the full completion of Option 2 is November 2027.

Next steps

This FPAR represents the final stage of the RIT-D process.

In accordance with the provisions set out in clause 5.17.5, paragraph (c) of the NER, interested stakeholders may, within 30 days after the publication of this report, dispute the conclusions made by JEN in this report with the Australian Energy Regulator (AER).

Accordingly, interested stakeholders who wish to dispute the recommendations outlined in this report must do so by 31 July 2025. Any parties raising such a dispute are also required to notify JEN at PlanningRequest@jemena.com.au. If no formal dispute is raised, JEN will commence with the investment activities necessary to proceed with the implementation of the preferred option.

For the purposes of referencing this RIT-D, this RIT-D is referred to as the "***Somerton Supply Area RIT-D***" identified need.

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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 386,000 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

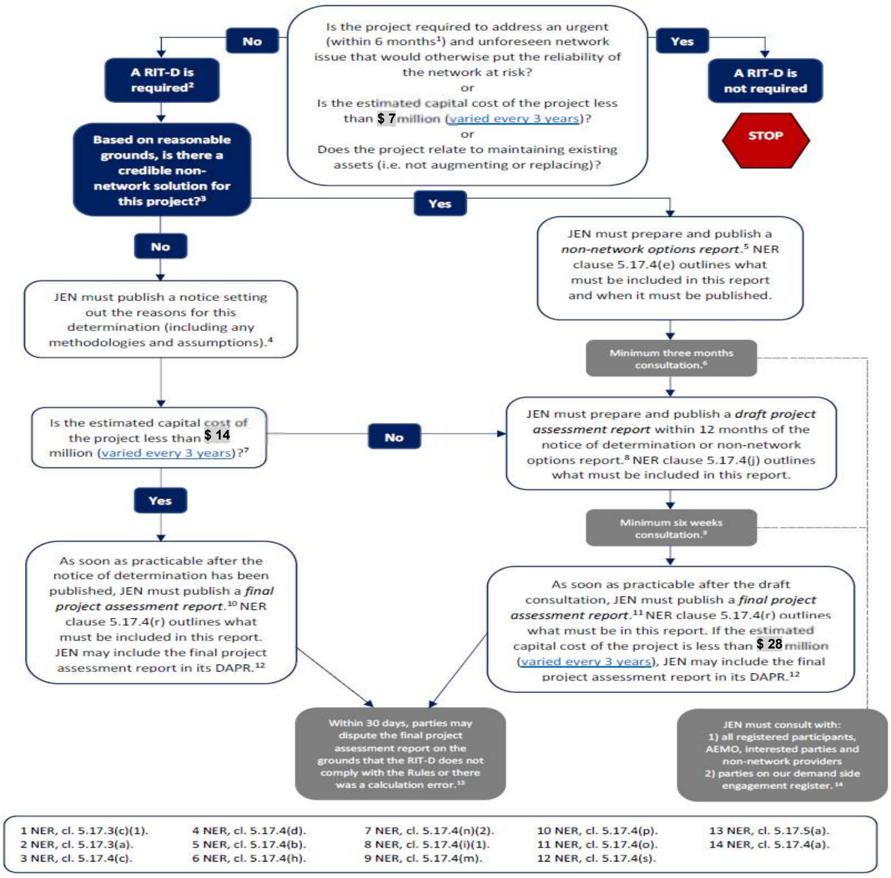
This section outlines the purpose of the Regulatory Investment Test for Distribution (**RIT-D**) in relation to the Somerton supply area, and the structure of this Final Project Assessment Report (**FPAR**).

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).[5] 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[6]. 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



[5] 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.

[6] 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[7] was published because it was identified by JEN that a non-network or SAPS solution may be potentially viable to address the identified need.

After the conclusion of the consultation on this options screening report, JEN published for consultation a draft project assessment report[8] (DPAR) to economically assess and identify the proposed preferred option.

We have now concluded the consultation on the DPAR and are at the final stage of the RIT-D process. As such, JEN has now prepared this FPAR to finalise the RIT-D.

1.2 Structure of this report

The objective of this FPAR 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 preferred option, taking into consideration any changes since the DPAR[9] and any submissions on the DPAR[10].

The contents of this FPAR 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 draft project assessment 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 preferred credible option, and next steps.

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

[8] RIT-D Stage 2: Draft Project Assessment Report, Jemena, 18 December 2024.

[9] Changes have arisen in maximum demand forecasts, and value of customer reliability (VCR) since the DPAR.

[10] No submissions were received on the DPAR.

2. Identified need

The NER requires that the FPAR must set out the matters detailed in the DAPR including a description of the identified need.[11,12]

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.

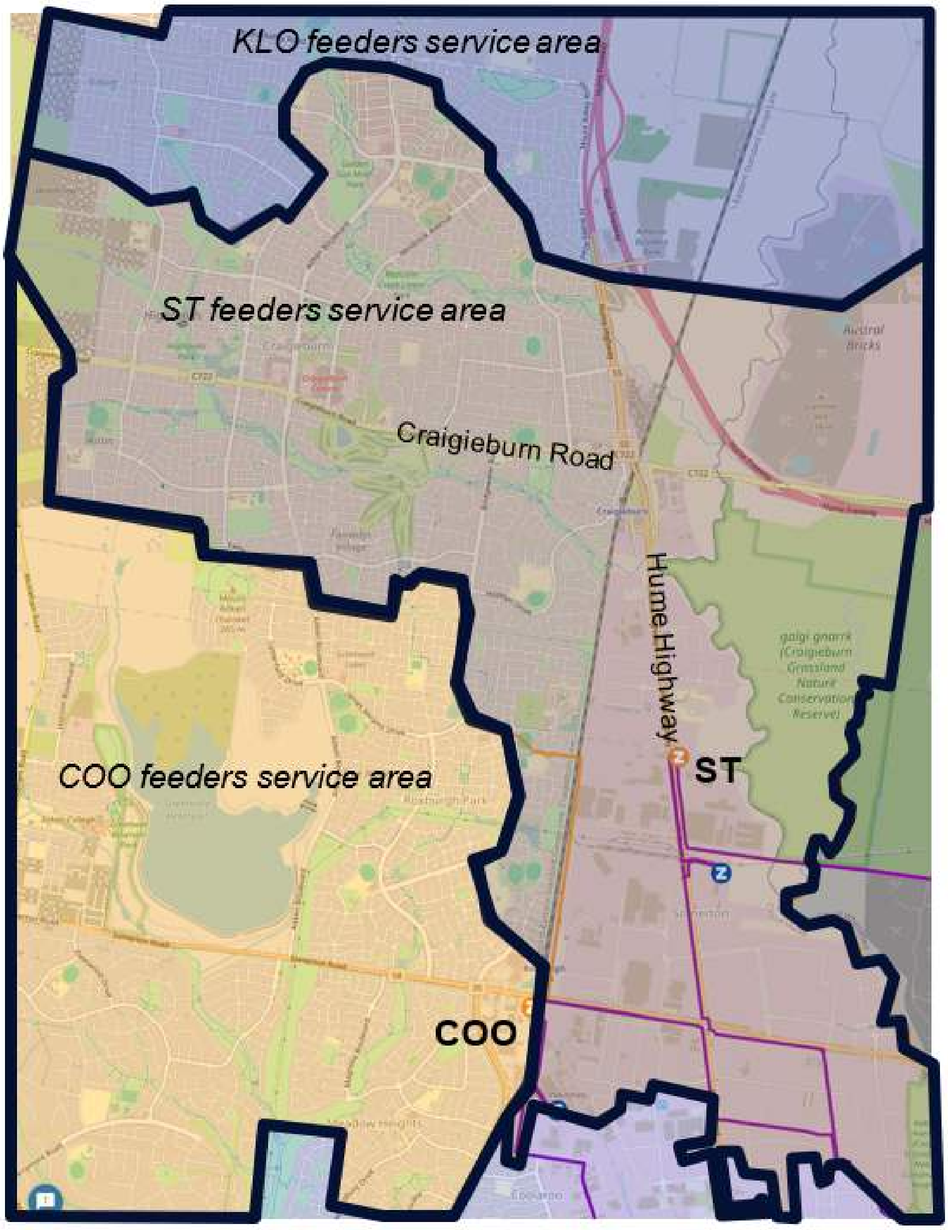
2.1 Somerton supply area

Somerton (**ST**) zone substation is owned and operated by JEN, providing power to more than 23,820 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.

[11] NER, clause 5.17.4(r)(i).

[12] NER, clause 5.17.4(j)(1).

Figure 2–1: JEN Somerton supply area



2.2 Somerton (ST) zone substation

Lying within Melbourne's Northern Growth Corridor[13], 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.

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

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 82.0 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 114 MVA. This rapid increase in the maximum demand forecast over the next several years is largely the result of 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) expected to be connected upstream of ST on its sub-transmission network by 2034. 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 both system normal and single contingency conditions, and to 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 the capacity of the existing 22 kV buses to support additional feeders needed to meet increasing demand within the Somerton supply area.

A credible solution to the identified need should seek to maintain reliable supply levels 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 both 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 mitigate.

2.4 Quantification of the identified need

The annual value of EUE associated with the ST's network capacity and demand profile[14] (taking into account asset ratings, probability of failure, repair time and the available transfer capacity), are presented in Table 2–1. They are based on a locational VCR of $38,685 per MWh which has been derived from the estimates in the Australian Energy Regulator's (AER) Values of Customer Reliability Review published in December 2024.[15]

Table 2–1: Value of EUE ($k, 2024) (central scenario)[16]

Year	Reliability Risk (MWh)	Reliability Risk Cost ($k)
2025	30	1,165

[14] 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.

[15] AER, Values of customer reliability: Final report on VCR values, December 2024.

[16] Distribution feeder EUE limitations are capped at 2031 levels beyond this year.

Year	Reliability Risk (MWh)	Reliability Risk Cost ($k)
2026	114	4,396
2027	2,739	105,975
2028	9,971	385,740
2029	20,535	794,382
2030	33,302	1,288,298
2031	46,080	1,782,604
2032	46,098	1,783,317
2033	46,153	1,785,413
2034	46,285	1,790,526

3. Assumptions relating to the identified need

The NER requires that the FPAR must set out the matters detailed in the DAPR including the assumptions used in identifying the identified need.[17,18] This section addresses this requirement.

In accordance with the purpose of the RIT-D outlined in clause 5.17.1 (b) of the NER, an investment to address the identified need relating to the reliability of supply risks within the Somerton supply area, 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 in the area 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) values based on the estimates in the Australian Energy Regulator's (**AER**) Values of Customer Reliability Review published in December 2024. 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**).[19]

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

3.1 Demand forecasts

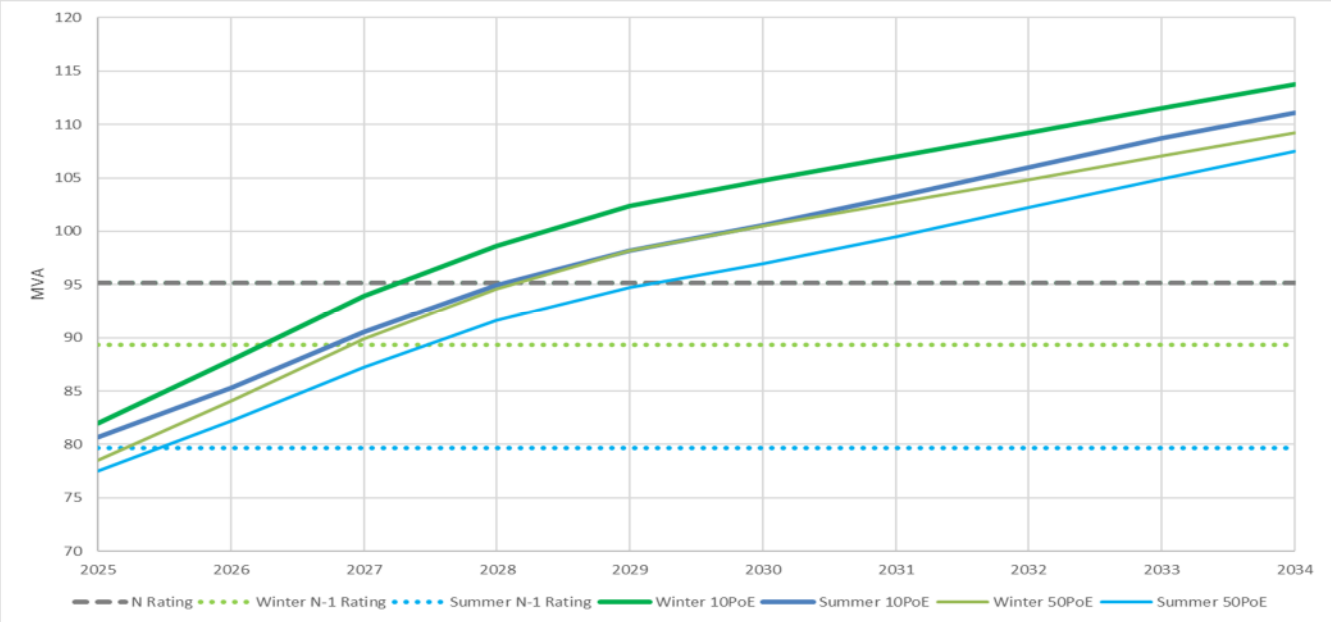
JEN has updated the maximum demand forecast to reflect the 2024 forecast for this FPAR. The updated maximum demand forecasts and capacity ratings for ST are shown in Figure 3–1.

[17] NER, clause 5.17.4(r)(i).

[18] NER, clause 5.17.4(j)(2).

[19] JEN, 2024 Distribution Annual Planning Report, 9 December 2024, section 2.4.

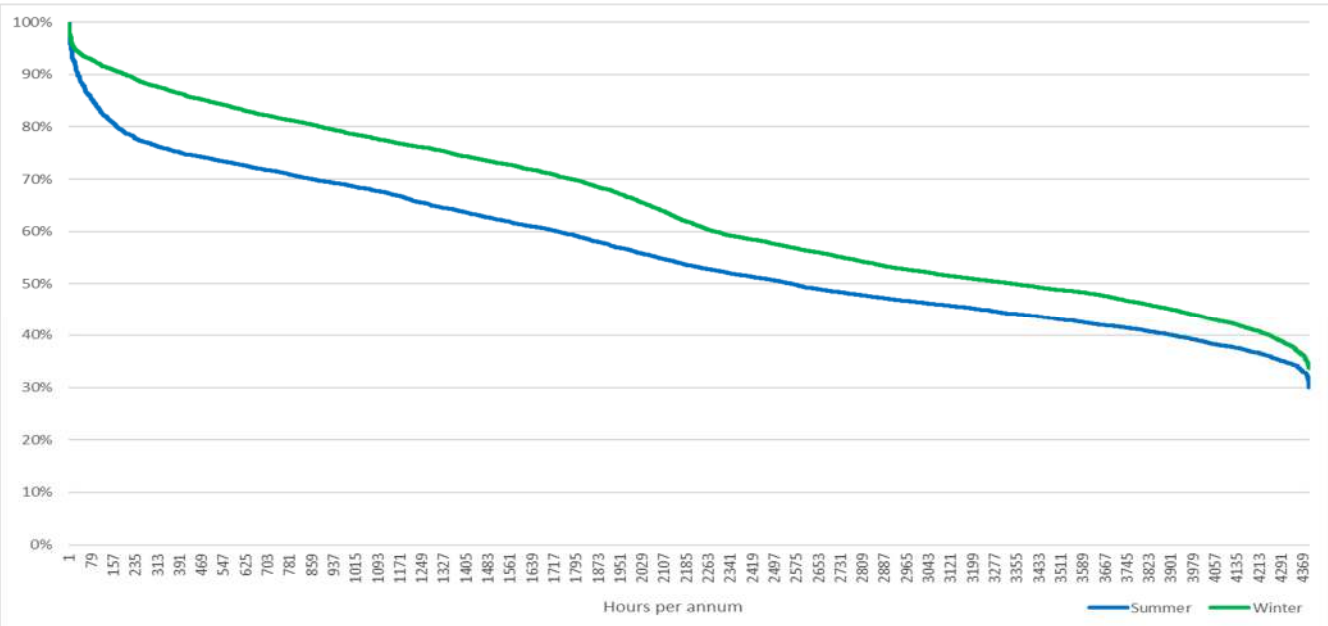
Figure 3–1: ST maximum demand forecast and ratings (MVA)



ST is expected to exceed its N rating by 2028 for a 10% PoE winter maximum demand, and 2029 for a 50% PoE winter maximum demand. The N rating is expected to be exceeded in summer from 2029. ST is already exceeding its N-1 rating for a 10% PoE summer maximum demand, and is expected to exceed its N-1 rating by 2026 for a 50% PoE. The N-1 rating is expected to be exceeded in 2027 for a 10% and 50% PoE winter maximum demand.

The duration of the demand experienced at ST is illustrated in Figure 3–2 with a summer load factor[20] of 0.56 and a winter load factor of 0.64.

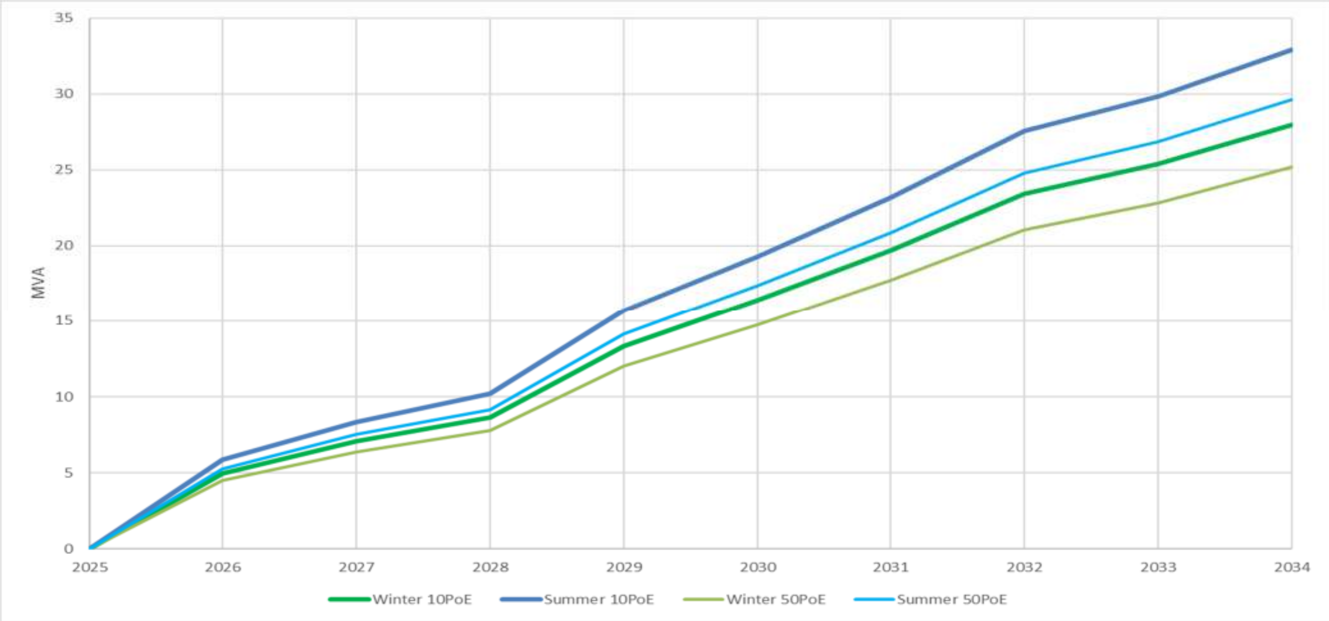
Figure 3–2: ST load-duration curve (% of summer and winter maximum demand)



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

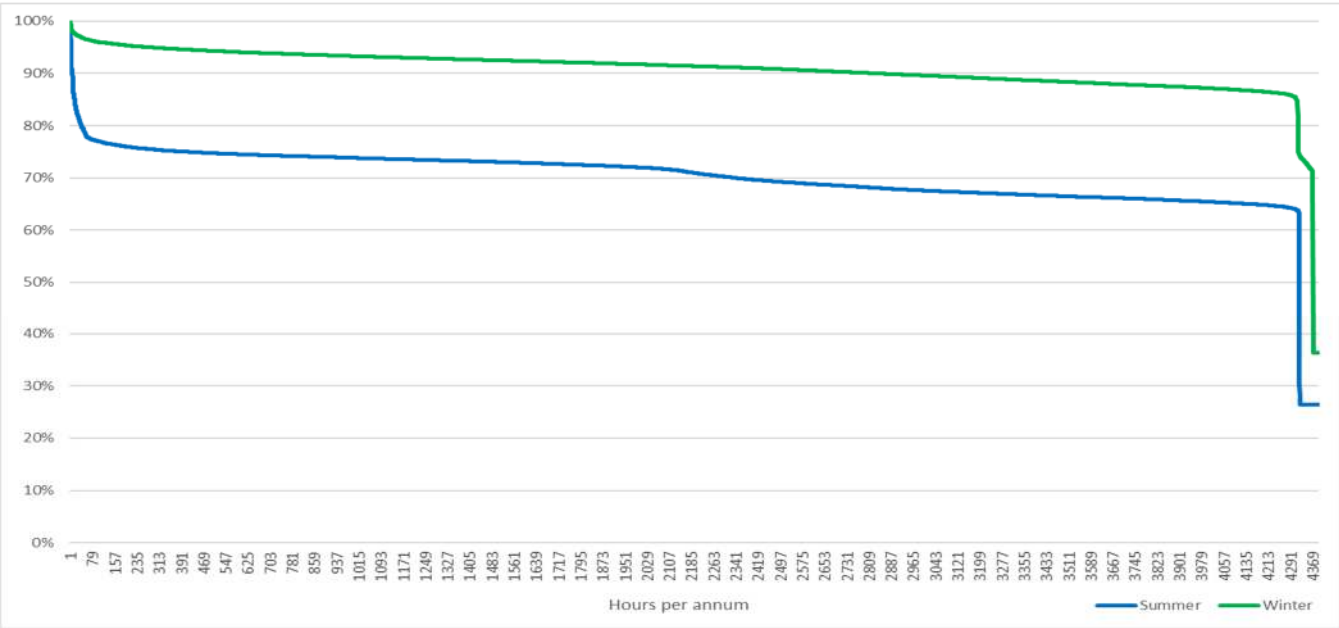
[20] Load factor is the average demand divided by maximum demand.

Figure 3–3: Major customer maximum demand forecast (MVA)[21]



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 the ST zone substation other than the small LV-connected residential and commercial solar PV systems. At ST, there are approximately 7,600 solar PV installations with a combined capacity of 38 MW, representing a penetration rate of 39% of customers.

[21] As at forecast completed in August 2024.

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 the capacity of the existing 22 kV buses to support additional feeders needed 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 draft report

The NER requires that the FPAR must set out a summary of any submissions received on the DPAR including the RIT-D proponent's response to each submission.[22]The NER also requires that, if applicable, a summary on the submissions on the non-network options report must be included in the FPAR.[23] This section summarises the consultation to date and the submissions received on the options screening report and draft project assessment report.

Stage 1 consultation

A RIT-D stage 1 Consultation Options Screening Report was published on JEN's website on 22 August 2024. This report outlined the potential credible options being considered and assessed whether the proposed network solutions to address the need, could be modified in scope or replaced by a non-network or SAPS solution. The analysis concluded that there may be a credible non-network or SAPS option (or a combination of such options, including with a network option) that could address the identified need within the Somerton supply area.

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

Stage 2 consultation

A RIT-D stage 2 Consultation Draft Project Assessment Report was published on JEN's website on 18 December 2024. The report presented the economic evaluation of the potential credible options being considered. Based on the analysis, Option 2 was identified as the preferred solution to address the identified need within the Somerton supply area.

JEN did not receive any submissions, nor any proposals for alternative non-network or SAPS solutions, during the stage 2 consultation period.

22 NER, clause 5.17.4(r)(ii).

23 NER, clause 5.17.4(r)(1)(i); clause 5.17.4(j)(3).

5. Options considered in the RIT-D

The NER requires that the FPAR must set out the matters detailed in the DAPR including a description of each credible option assessed.[24] [25]

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. This not considered a credible option going forward due to the associated EUE risk.

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);

24 NER, clause 5.17.4(r)(i).

25 NER, clause 5.17.4(j)(4).

- $21.12 million[26] (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[27]; and
- $2.00 million (real $2024)[28] for the cost of establishing CBN land services and access.

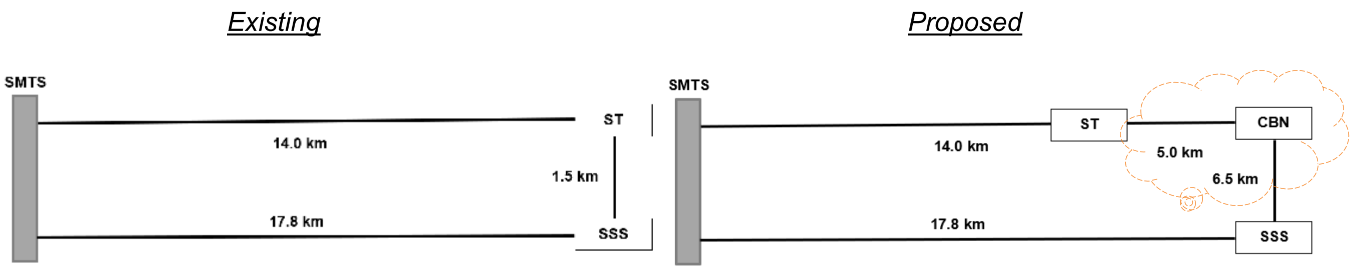
Operating costs are expected to be approximately one per cent of capital expenditure for all components other than land procurement, services and access, i.e., $0.76m per year..

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.

26 This cost excludes customer contributions.

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

28 $1.57 million cost already incurred in 2016. 1.27 multiple to real 2024 = $2.00 million.

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, however Option 3 is significantly more expensive compared to 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);
- $21.12 million[29] (real $2024) 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).

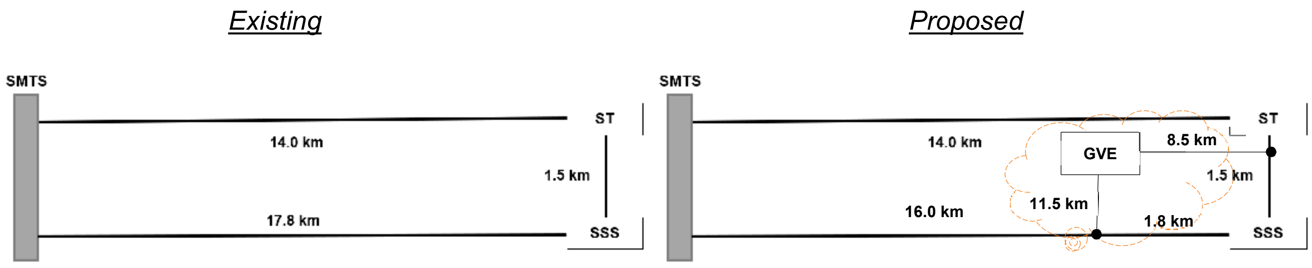
Operating costs are expected to be approximately one per cent of capital expenditure for all components other than land procurement, services and access, i.e., $1.06 million per year.

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	3 years	2027/28

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



[29] This cost excludes customer contributions.

6. Assessment methodology

The NER requires that the FPAR must set out the matters detailed in the DAPR including a detailed description of the methodologies used in quantifying each class of cost and market benefit, and 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.[30] [31]

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 to compare 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 2024 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 $38,685 per MWh.[32]

Table 6-1: Load weighted VCR calculation

Parameter	Residential[33]	Commercial	Industrial
Somerton supply area load composition	22%	49%	29%
AER VCR (Dec 2024[34])	$55.10/kWh	$34.39/kWh	$33.49/kWh
Load weighted VCR	$38.685/kWh		

6.1.3 Assessment period

This RIT-D analysis has been undertaken over a ten-year period, from 2024/25 to 2033/34. The duration of the assessment reflects the size, complexity and expected asset life of the relevant credible options, providing a

30 NER, clause 5.17.4(r)(i).

31 NER, clause 5.17.4(j)(7)-(8).

32 JEN has updated the VCR used in the DPAR to the AER's 2024 values for this FPAR.

33 Suburban, climate zone 6.

34 Values of Customer Reliability 2024 | Australian Energy Regulator (AER).

reasonable basis for evaluating their associated market benefits and costs. It also captures the impact of expected demand growth in the Somerton supply area, which the credible options are intended to address.

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 annual operating and maintenance costs have also been included in the assessment.

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 incorporate them in the assessment. This 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 FPAR.

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. 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 FPAR, 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 2024 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 limited load transfer capacity to adjacent supply areas, which constrains the ability to reduce the reliability impacts in the event of an asset failure at ST. This limitation is therefore relevant when comparing options that provide different levels of transfer capacity.

JEN has incorporated changes in load transfer capacity into the involuntary load shedding market benefit assessment 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. 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 FPAR.

6.4.3 Timing of expenditure

JEN has assessed that the timing of other unrelated expenditure is not affected by the options considered in this assessment. As a result, this market benefit was not quantified, as it is not considered relevant for distinguishing 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. However, the network options 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 retaining flexibility would not deliver any material value in this case. JEN has therefore not sought to identify flexible options or quantify any additional option value market benefit as part of 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 options are not expected to have an impact on wholesale market generation dispatch, renewable energy curtailment 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 undertake 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

The NER requires that the FPAR must set out the matters detailed in the DAPR including the results of net present value analysis of each credible option and accompanying explanatory statements.[35] [36]

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	4,997	9,087	11,574	**8,679**

7.2 Option 2 – Craigieburn (CBN) development plan

The table below sets out the gross market benefits under Option 2 (i.e., the avoided EUE risk cost relative to Option 1, the base case), the total costs of Option 2 and the resulting net market benefit (all expressed in present value terms) across all scenarios 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	4,880	8,986	11,456	**8,577**
Total option costs	75.9	75.9	75.9	75.9
Net Market Benefit	4,805	8,910	11,380	**8,501**

7.3 Option 3 – Greenvale (GVE) development plan

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

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

Option 3	Low Scenario	Central Scenario	High Scenario	Weighted Total
Gross Market Benefit	4,599	8,655	11,077	**8,246**
Costs	102.5	102.5	102.5	102.5
Net Market Benefit	4,497	8,553	10,974	**8,144**

35 NER, clause 5.17.4(r)(i).

36 NER, clause 5.17.4(j)(9).

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.

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	8,577	8,501	1
Option 3 – Greenvale (GVE) development plan	102.5	8,246	8,144	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

Section 6.5 defines two sets of sensitivities designed to test the robustness of the option rankings under the NPV assessment against changes in key assumptions. The sensitivity analysis focuses on the central scenario and evaluates the impact of varying one assumption at a time.

The sensitivity analysis demonstrates that the conclusion–Option 2 being the preferred option– is robust to the changes in assumptions tested, as the ranking of the options remains unchanged. This is 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	**8,910**	**8,553**	**Option 2**
Maximum demand forecast	5,667	5,310	Option 2
Value of customer reliability	6,214	5,956	Option 2
Capital cost	8,933	8,522	Option 2
Discount rate	10,889	10,502	Option 2
Asset failure rate	7,562	7,254	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	**8,910**	**8,553**	**Option 2**
Maximum demand forecast	9,887	9,529	Option 2
Value of customer reliability	11,606	11,162	Option 2
Capital cost	8,887	8,583	Option 2
Discount rate	7,841	7,501	Option 2
Asset failure rate	10,257	9,851	Option 2

As a threshold test, we have identified what the increase in capital expenditure would need to be for Option 2 to make it no longer rank above Option 3. This value is $104.9 million (i.e., 139% higher). This is not considered credible.

7.6 Preferred option optimal timing

The optimal timing of the 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 $4.7 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	2026	2027	2028	2029	2030	Optimal Timing
Weighted	**28,002**	**159,224**	**416,839**	**763,847**	**1,174,504**	**2025/26**
Central	(268)	101,311	381,077	789,718	1,283,635	2026/27
Low	(4,663)	(4,168)	(3,673)	(927)	85,415	2029/30
High	117,208	438,938	908,875	1,476,879	2,045,331	2025/26

The optimal completion date for the entire option is by 2025/26 for the weighted scenario. However, with construction lead time taken into account, 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 the full completion of Option 2 is November 2027.

8. Conclusion and next steps

The NER requires that the FPAR must set out the matters detailed in the DAPR including the identification of the proposed preferred option including technical details, implementation timing, indicative costs and detailed analysis which shows that the preferred option satisfies the RIT-D.[37] [38]

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

8.1 Preferred option

As summarised in Table 8–1, the 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	8,577	8,246
Net Market Benefits (NPV)	**0**	**8,501**	**8,144**

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 preferred option has a total capital cost of $75.46 million (real $2024), and is expected to incur additional annual operating expenditure of $0.76m. The RIT-D assessment has demonstrated that the preferred option is expected to deliver a net economic benefit of $8,501 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 lead time taken into account, 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 the full completion of Option 2 is November 2027.

8.2 Next steps

This FPAR represents the final stage of the RIT-D process.

In accordance with the provisions set out in clause 5.17.5, paragraph (c) of the NER, interested stakeholders may, within 30 days after the publication of this report, dispute the conclusions made by JEN in this report with the Australian Energy Regulator (AER).

Accordingly, interested stakeholders who wish to dispute the recommendations outlined in this report must do so by 31 July 2025. Any parties raising such a dispute are also required to notify JEN at PlanningRequest@jemena.com.au. If no formal dispute is raised, JEN will commence with the investment activities necessary to proceed with the implementation of the preferred option

[37] NER, clause 5.17.4(r)(i).

[38] NER, clause 5.17.4(j)(10)-(11).

For the purposes of referencing this RIT-D, this RIT-D is referred to as the "***Somerton Supply Area RIT-D***" identified need.

9. Appendix A – Checklist of compliance clauses

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

Table 9–1: Compliance clauses checklist

Clause	Section
5.17.4(j)(1) a description of the identified need for the investment;	2
5.17.4(j)(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
5.17.4(r)(1)(ii) if applicable, a summary of, and commentary on, the submissions on the draft project assessment report;	4
5.17.4(j)(4) a description of each credible option assessed;	5
5.17.4(j)(7) a detailed description of the methodologies used in quantifying each class of cost and market benefit;	6.3 & 6.2
5.17.4(j)(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
5.17.4(j)(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
5.17.4(j)(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	5 & 7
5.17.4(j)(9) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7.4
5.17.4(j)(10) the identification of the preferred option;	8.1
5.17.4(j)(11) for the 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 preferred option satisfies the regulatory investment test for distribution; and(v) if the preferred option is for reliability corrective action and that option has a proponent, the name of the proponent.	8.1