Altona-Brooklyn Terminal Station Capacity Constraint

RIT-T Stage 2: Project Assessment Draft Report (PADR)

Executive summary

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and Powercor Australia Ltd. (**Powercor**) are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, servicing more than 384,000 and 945,000 customers respectively, within Melbourne's northern and western greater metropolitan area, and in central western regional Victoria.

As expected by our customers and required by the various regulatory instruments, JEN and Powercor aim to maintain service levels at the lowest possible cost for our customers. To achieve this, options are assessed and plans developed that maximise the present value of net economic benefit. Where relevant, this includes preparation of, and consultation on, regulatory investment tests.

In Victoria, the DNSPs have responsibility for planning and directing augmentation of the transmission connection assets that connect their distribution systems to the Victorian shared transmission system. This report relates to proposed investment on the transmission connection assets at Altona-Brooklyn Terminal Station (**ATS-BLTS**) and as such, is subject to a regulatory investment test for transmission (**RIT-T**). ATS-BLTS supplies electricity to parts of the JEN (the lead proponent of this RIT-T) and Powercor electricity distribution networks.

This project assessment draft report (**PADR**) is the second stage of the **Altona-Brooklyn Terminal Station Capacity Constraint RIT-T** consultation process. It has been jointly prepared by JEN and Powercor in accordance with the requirements of clause 5.16 of the *National Electricity Rules* (**NER**)[1] and section 4.3 of the *RIT-T Application Guidelines*[2].

Identified need

The identified need for this RIT-T is to deliver market benefits by maintaining electricity supply reliability and mitigating forecast increases in expected unserved energy (**EUE**) for those customers supplied from ATS-BLTS 66 kV [3], while enabling the connection of new data-centre load within the supply area.

ATS-BLTS 66 kV supplies electricity to approximately 64,022 customers, with the supply area including major geographic centres such as Altona, Brooklyn, Laverton, Tottenham, Footscray, Newport, Spotswood, Williamstown and Yarraville.

Due to expected increase in electricity demand within the supply area from existing, and prospective major data-centre connections, the emerging level of EUE resulting from capacity limitations at ATS-BLTS 66 kV is forecast to grow if action is not taken, resulting in a deterioration of supply reliability for our customers.

Addressing this identified need by reducing the forecast EUE with a prudent level of investment in a network, non-network or standalone power system solution is expected to result in a positive net economic benefit.

The need for this investment has been foreshadowed in the *Transmission Connection Planning Reports* (**TCPR**), published jointly by the Victorian DNSPs[4].

[1] National Electricity Rules, version 243, Australian Energy Market Commission (AEMC), 2026.

[2] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.

[3] The 66 kV bus group at Brooklyn Terminal Station (BLTS) currently operates in parallel with the Altona Terminal Station (ATS) 66 kV bus group No.1 and No. 2 via transformers BLTS B1, BLTS B3 and ATS B2, being two terminal stations in close proximity, connected by strong 66 kV sub-transmission ties. For the purposes of this RIT-T, this combined Altona-Brooklyn Terminal Station (ATS-BLTS) 66 kV bus group has been abbreviated to ATS-BLTS 66 kV as distinct from ATS West which operates as a completely separate terminal station at the ATS site. The ATS West RIT-T undertaken by Powercor has no bearing on this ATS-BLTS 66 kV RIT-T, except that ATS B2 will become ATS B1 following the ATS West RIT-T preferred option.

[4] Transmission Connection Planning Report, Victorian Distribution Network Service Providers, 2025.

Potential credible options

The potential credible options considered in this PADR to address the identified need include:

- **Option 1** - do nothing (base case). This is not considered a credible option going forward due to the associated EUE risk;
- **Option 2** - non-network or SAPS solution;
- **Option 3** – establish a new BLTS North 66 kV bus group (B48); and
- **Option 4** – upgrade the existing ATS-BLTS 66 kV bus group (B2).

The project specification consultation report (**PSCR**) published in September 2025, flagged Option 4 as the likely preferred network option that would maximise the net market benefits. The estimated capital cost of this investment option to address the identified need exceeds the trigger of $8 million[5] for undertaking a RIT-T. Both network options identified in the PSCR are assessed in this PADR.

No non-network proposals were received during the Altona-Brooklyn supply area RIT-T PSCR consultation. Therefore Option 2 is not considered to be a credible option for the purposes of this PADR in addressing the identified need.

Assessment approach

The Australian Energy Regulator's (**AER**) *RIT-T Application Guidelines* have been applied to analyse and rank the economic cost and benefits of the investment options considered in this RIT-T across a range of reasonable scenarios. The robustness of the ranking and optimal timing of options has been investigated through sensitivity analysis involving variations of assumptions around the values used in the base case. None of the options considered have a material impact on wholesale market costs. Hence no market simulation studies have been conducted for this RIT-T.

Options assessment and draft conclusion

The preferred option is the one that maximises the present value of the net economic benefit, weighted across a set of reasonable state-of-the-world scenarios. A summary of the net present value (**NPV**) analysis for each credible option and each scenario is provided in Table 1-1.

Table 1-1: Calculated present value of net economic benefits relative to base case ($ million, real 2025)

Option	Low Scenario	Central Scenario	High Scenario	Weighted Scenario	Ranking
	25%	**50%**	**25%**	**100%**	
1	0	0	0	0	3
3	(52)	542	1,614	662	2
4	182	1,162	2,924	1,358	1

The cost-benefit economic evaluation assessment undertaken for this PADR has concluded that the preferred option to address the identified need for this RIT-T is Option 4, being the upgrade of the existing ATS-BLTS 66 kV bus group with a new 220/66 kV 150 MVA transformer. The preferred option is found to have positive net benefits under all scenarios and sensitivities investigated. On a weighted basis, it will deliver $1,358 million in present value net economic benefits over the 10-year analysis period. The estimated capital cost of this option is $29.8 million (real, 2025) with an optimum timing of 2027-28. This option satisfies the requirements of the RIT-T.

[5] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER).

Submissions

JEN and Powercor invite written submissions and enquiries on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "**Altona-Brooklyn Terminal Station Capacity Constraint RIT-T**" and directed to both:

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The consultation on this PADR is open for 6 weeks. Submissions are due on or before 18 September 2026. Submissions will be published on the Australian Energy Market Operator (**AEMO**), JEN and Powercor websites. If you do not wish for your submission to be published, please clearly stipulate this at the time of lodging your submission.

Next steps

Following conclusion of the PADR consultation period, JEN and Powercor will, having regard to any submissions received on the PADR, prepare and publish a project assessment conclusions report (**PACR**) including:

- a summary of, and commentary on, the submissions on the PADR;
- the matters detailed in the PADR; and
- confirmation of the preferred option to meet the identified need.

Publication of that report will conclude consultation on this RIT-T.

JEN and Powercor intend to publish the PACR by the end of 2026.

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Glossary

Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Contingency condition ('N-1')	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.
Distributor (DNSP)	A distribution network service provider.
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 probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for a cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services 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.
Network	Refers to the system of 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 capability 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 Transmission (RIT-T)	An economic viability test that establishes consistent, clear and efficient planning processes for assessing and consulting on transmission network investments over a prescribed limit.
Stand Alone Power System (SAPS)	An embedded power system that operates disconnected (islanded) from the network.
System Normal condition ('N')	The condition where no network assets are under maintenance or forced outage, and the network is operating in a normal configuration.
Terminal Station	A substation facility that houses transmission connection assets, connecting the distribution network to the Victorian transmission system.
Transmission Connection Asset	Transmission assets within a terminal station that are under the planning responsibility of the distributors connected to those assets.
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).
POE10 (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, with the demand expected to be exceeded every ten years.
POE50 (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, with the demand expected to be exceeded every two years.
POE50 and POE10 (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, with the demand expected to be exceeded every two years and every ten years respectively.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AL	Altona Zone Substation
ATS	Altona Terminal Station
ATS-BLTS	Altona-Brooklyn Terminal Station
BMH	Bacchus Marsh Zone Substation
BLTS	Brooklyn Terminal Station
DNSP	Distribution Network Service Provider (distributor)
EUE	Expected Unserved Energy
FW	Footscray West Zone Substation
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo-Volts
LVN	Laverton North Zone Substation
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System Normal Condition
N.O.	Normally Open
N-1	Single Contingency Condition
NER	National Electricity Rules
NPV	Net Present Value
NSA	Network Support Agreement
NSP	Network Service Provider
O&M	Operations and Maintenance
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
POE	Probability of Exceedance
PSCR	Project Specification Consultation Report
RIT-T	Regulatory Investment Test for Transmission
SAPS	Stand Alone Power System
TCPR	Transmission Connection Planning Report
TH	Tottenham Zone Substation
VCR	Value of Customer Reliability
YVE	Yarraville Zone Substation

1. Introduction

Jemena Electricity Networks (Vic) Ltd. (**JEN**) and Powercor Australia Ltd. (**Powercor**) are regulated electricity distribution network service providers (**DNSPs**) operating in Victoria, servicing more than 384,000 and 945,000 customers respectively, within Melbourne's northern and western greater metropolitan area, and across central western regional Victoria.

The regulatory investment test for transmission (**RIT-T**) is an economic cost-benefit test and consultation process, used to seek, assess and rank potential investments capable of meeting an identified need. The purpose of a RIT-T is to identify the credible option that maximises the present value of net economic benefit (the preferred option). The process follows the requirements in clauses 5.15A and 5.16 of the *National Electricity Rules* (**NER**)[6].

The RIT-T 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 the threshold of $8 million[7]. The RIT-T process is summarised in Figure 1-1, overleaf.

This RIT-T is being undertaken to evaluate options to maintain reliability of supply and to connect new data-centre loads within the Altona-Brooklyn Terminal Station (**ATS-BLTS**) supply area (the identified need). Options investigated in this RIT-T aim to mitigate the risk of growing expected unserved energy (**EUE**), resulting in a forecast deterioration of power supply reliability. The capital cost of the network options to address this identified need within the supply area is above the RIT-T cost threshold, triggering the requirement for a RIT-T.

The project specification consultation report (**PSCR**) for the first stage of the **Altona-Brooklyn Terminal Station Capacity Constraint RIT-T** consultation was published in September 2025 in accordance with section 4.2 of the *RIT-T Application Guidelines*[8]. No submissions for non-network proposals were received during the RIT-T PSCR consultation stage.

We have now published this project assessment draft report (**PADR**), representing the second stage of the **Altona-Brooklyn Terminal Station Capacity Constraint RIT-T** consultation process, in accordance with section 4.3 of the *RIT-T Application Guidelines*.

The structure of this PADR is as follows:

- **Chapter 2** describes the identified need that JEN and Powercor are seeking to address, which is in relation to the ATS-BLTS capacity limitations;
- **Chapter 3** identifies credible options that aim to address the identified need;
- **Chapter 4** provides a summary and commentary on the submissions to the PSCR;
- **Chapter 5** presents the scope, costs and benefits of the credible options;
- **Chapter 6** details the assessment approach and assumptions that JEN and Powercor have employed for this RIT-T assessment, as well as the materiality of specific categories of market benefits;
- **Chapter 7** presents the results of the net present value analysis for each option and identifies the proposed preferred option and its optimal timing, along with scenario and sensitivity analysis results to confirm the robustness of the proposed preferred option to credible changes in assumptions; and
- **Chapter 8** presents the conclusions of the PADR, details of the proposed preferred option, and next steps.

The need for investment has been foreshadowed in the *Transmission Connection Planning Report* (**TCPR**)[9], published jointly by the Victorian DNSPs.

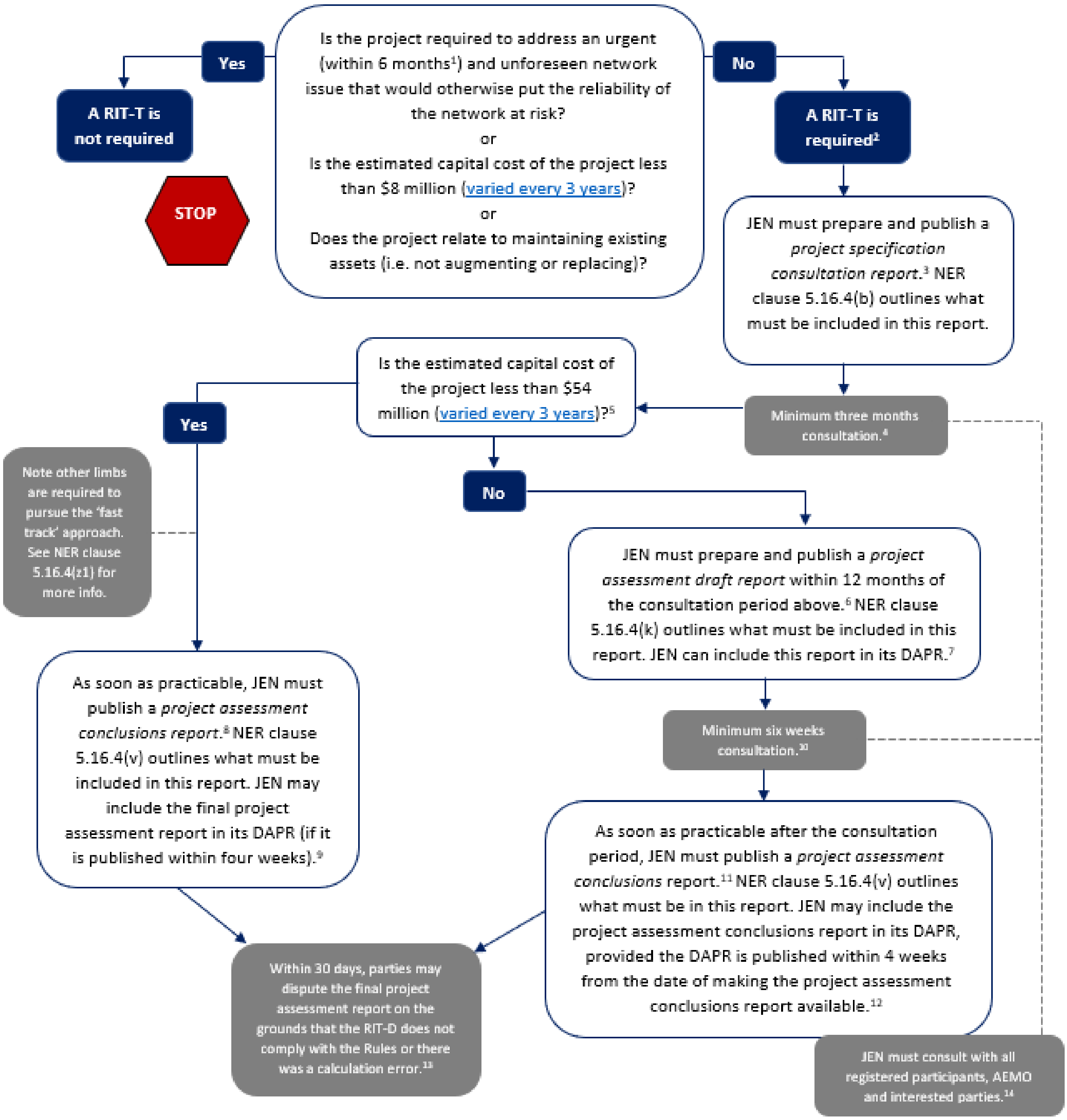
[6] National Electricity Rules, version 243, Australian Energy Market Commission (AEMC), 2026.

[7] AER publishes final determination on the 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER).

[8] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.

[9] Transmission Connection Planning Report, Victorian Distribution Network Service Providers, 2025.

Figure 1-1: RIT-T process flow chart



1 NER, cl. 5.16.3(b).
2 NER, cl. 5.15A.1(b).
3 NER, cl. 5. 5.16.4(b).
4 NER, cl. 5.16.4(g).
5 NER, cl. 5.16.4(z1).
6 NER, cl. 5.16.4(j).
7 NER, cl. 5.16.4(n).
8 NER, cl. 5.16.4(u)(1).
9 NER, cl. 5.16.4(z).
10 NER, cl. 5.16.4(r).
11 NER, cl. 5.16.4(t).
12 NER, cl. 5.16.4(z).
13 NER, cl. 5.16B(c).
14 NER, cl. 5.16.4(a).

2. Description of the identified need

This chapter discusses the role of ATS-BLTS in providing electricity network services and the identified need associated with its current and forecast capacity limitations. Quantification of the risk and costs associated with the forecast increase in EUE in the base case (i.e., the status-quo where no investment is undertaken) is also presented.

2.1 Supply area

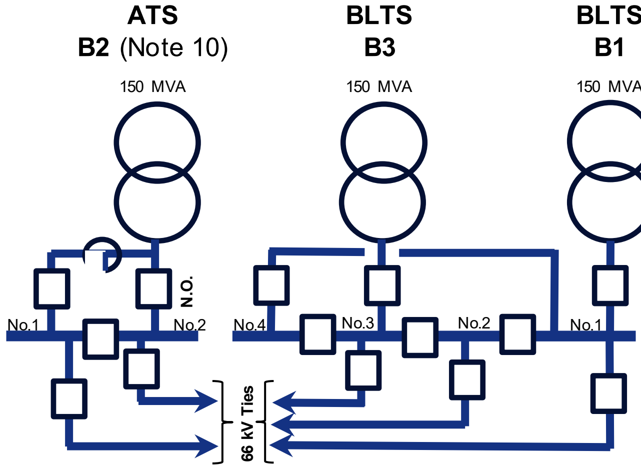
ATS-BLTS is in the inner-west of Greater Melbourne. It operates at 220/66 kV and supplies major geographic centres such as Altona, Brooklyn, Laverton, Tottenham, Footscray, Newport, Spotswood, Williamstown and Yarraville.

Electricity demand at ATS-BLTS is soon expected to be one of the fastest growing in Victoria, with JEN receiving more than eight recent major data-centre connection requests within the Brooklyn supply area, an industrial area located north of ATS-BLTS. If only one of these data-centre connections proceeds to full load, ATS-BLTS will have exceeded its full capacity.

2.1.1 Electricity network servicing the supply area

ATS-BLTS 66 kV bus group has three 150 MVA transformers (two located at BLTS being B1 and B3, and one remotely located at ATS being B2 currently[10]). Under system normal conditions, all three transformers are operated in parallel with B2 being connected through to B3 and B1 via multiple 66 kV tie lines (between ATS and BLTS) with each tie having zone substation load connected along the way. For an unplanned transformer outage of any one of the three transformers, the bus group reduces to two transformers in parallel. This is illustrated in Figure 2-1.

Figure 2-1: ATS-BLTS 66 kV simplified single line diagram (existing)



The summer cyclic rating of ATS-BLTS 66 kV with all plant in service is 508 MVA and with one of its three 220/66 kV 150 MVA transformers out of service, reduces to 340 MVA (summer) and 366 MVA (winter).

[10] The 66 kV bus group at Brooklyn Terminal Station (BLTS) currently operates in parallel with the Altona Terminal Station (ATS) 66 kV bus group No.1 and No. 2 via transformers BLTS B1, BLTS B3 and ATS B2, being two terminal stations in close proximity, connected by strong 66 kV sub-transmission ties. For the purposes of this RIT-T, this combined Altona-Brooklyn Terminal Station (ATS-BLTS) 66 kV bus group has been abbreviated to ATS-BLTS 66 kV as distinct from ATS West which operates as a completely separate terminal station at the ATS site. The ATS West RIT-T undertaken by Powercor has no bearing on this ATS-BLTS 66 kV RIT-T, except that ATS B2 will become ATS B1 following the ATS West RIT-T preferred option.

2.1.2 Customer demand for electricity

More than 64,022 customers rely on ATS-BLTS 66 kV for their electricity supply. Commercial customers currently account for 54.6% of the total annual energy supplied by ATS-BLTS 66 kV followed by large business, residential and industrial customers as illustrated in Table 2-1.

Table 2-1: ATS-BLTS 66 kV net energy consumption (GWh per annum, 2024)

Customer Type	ATS-BLTS 66 kV	Proportion
Commercial	1,522	54.6%
Residential	341	12.2%
Industrial	325	11.6%
Agricultural	<1	0.0%
Large Business > 10 MW	598	21.5%
Total	**2,786**	**100%**

There has been an unprecedented number of data-centre and major load connection enquiries in the ATS-BLTS supply area over the last two years. Many enquiries have needed feasibility assessments across multiple alternative locations within the service area. Some of the enquiries are now proceeding to formal connection applications and offers. Some connection options are frequently being tested by the applicants competitively across different distributors, whilst others are proceeding to construction.

More than eight recent major data-centre connection requests have been received by JEN within this supply area. As a result, the proportion of energy consumed by the Large Business category for ATS-BLTS is expected to grow substantially over the next ten to fifteen years. If only one of these data-centre connections proceeds to full load, ATS-BLTS 66 kV will have exceeded its full capacity.

Section 6.2.2 provides an overview of the maximum demand forecasts that underpin the identified need, and which reflect the expected connection of these new data-centre loads.

2.2 Identified need

There is forecast to be insufficient capacity to supply the forecast maximum demand at ATS-BLTS 66 kV based on the existing transmission connection assets. Without augmentation, this is likely to lead to a significant deterioration in supply reliability for customers supplied by this terminal station under system normal and single contingency conditions and inhibit the connection of new major data-centres within the supply area.

The identified need is to deliver market benefits from reduced EUE by maintaining electricity supply reliability for customers supplied from ATS-BLTS 66 kV and to connect new data-centre load within the supply area. Due to expected increases in electricity demand within the supply area from the prospective data-centre connections, the emerging level of EUE resulting from capacity limitations at ATS-BLTS 66 kV is forecast to grow as demand increases, deteriorating supply reliability for customers if action is not taken.

Addressing this identified need by reducing the forecast EUE with a prudent level of investment in a network, non-network or standalone power system solution is expected to result in a positive net economic benefit.

There are two drivers of EUE at ATS-BLTS - a lack of “N” capacity (with all plant in service), and a lack of “N-1” capacity (with one transformer out of service). We note that ATS-BLTS has load transfer capability available at the distribution feeder level. This capability allows risk to be managed in the short-term, by transferring load away from ATS-BLTS to surrounding terminal stations using spare capacity within each distribution network, reducing the level of EUE.

Table 2-2 summarises the forecast capacity limitations at ATS-BLTS 66 kV, considering the impacts of the committed data-centre connections load forecast on the overall demand at ATS-BLTS 66 kV.

Table 2-2: Forecast capacity limitations at ATS-BLTS 66 kV

ATS-BLTS 66 kV	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load at risk above 'N' (MVA)										
Summer POE10	0	107	145	150	146	147	151	156	157	157
Winter POE10	0	48	62	67	69	74	81	86	87	88
Summer POE50	0	70	106	109	106	108	112	116	117	116
Winter POE50	0	26	40	44	47	52	58	63	65	65
Time at risk above 'N' (h pa)										
Summer POE10	0	66	196	222	199	203	225	250	258	253
Winter POE10	0	8	12	15	16	19	23	26	27	27
Summer POE50	0	23	63	69	64	66	72	79	81	80
Winter POE50	0	4	7	8	8	9	11	13	13	14
Load at risk above 'N-1' (MVA)										
Summer POE10	132	170								
Winter POE10	109	183								
Summer POE50	95	170								
Winter POE50	87	183								
Time at risk above 'N-1' (h pa)										
Summer POE10	582	2,745	3,247	3,346	3,298	3,305	3,352	3,403	3,420	3,411
Winter POE10	257	2,369	2,600	2,658	2,688	2,741	2,819	2,881	2,893	2,898
Summer POE50	175	2,249	2,783	2,874	2,839	2,855	2,903	2,955	2,969	2,958
Winter POE50	97	2,067	2,317	2,380	2,417	2,473	2,554	2,615	2,632	2,640
Weighted EUE[11]										
'N' EUE (MWh)	0.0	989.9	3,024	3,463	3,147	3,274	3,750	4,302	4,474	4,387
'N-1' EUE (MWh)	63.7	1,610	2,265	2,418	2,407	2,470	2,597	2,712	2,744	2,740
Total EUE[12] (MWh)	**63.7**	**2,600**	**5,289**	**5,881**	**5,555**	**5,744**	**6,347**	**7,015**	**7,218**	**7,127**
Value of EUE ($m[13])	**2.4**	**96.7**	**196.7**	**218.7**	**206.6**	**213.6**	**236.0**	**260.9**	**268.4**	**265.0**

The value of EUE is derived by multiplying the level of EUE (in MWh) by an estimate of the Value of Customer Reliability (**VCR**). We have adopted the AER's escalated estimate of VCR published in December 2025 as discussed further in section 6.2.6.

The EUE is estimated to have a value to consumers of around $2.4 million (real, 2025) in 2026, rising rapidly thereafter as the N and N-1 ratings are exceeded to $265 million by 2035.

The key elements of the "Do nothing" supply reliability risk under the status-quo are shown in Figure 2-2 at ATS-BLTS 66 kV, considering the impacts of available transfer capacity.

[11] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE, also considering the risk reduction provided by the available load transfer capabilities and the likelihood of the operating conditions.

[12] The total EUE is the summation of the EUE contribution during 'N-1' single contingency conditions (considering asset unavailability), and the EUE contribution during 'N' system normal conditions, considering the demand profile and seasonal ratings throughout the year.

[13] Real, 2025.

Figure 2-2: ATS-BLTS 66 kV EUE risk costs (including impact of load transfer capability)

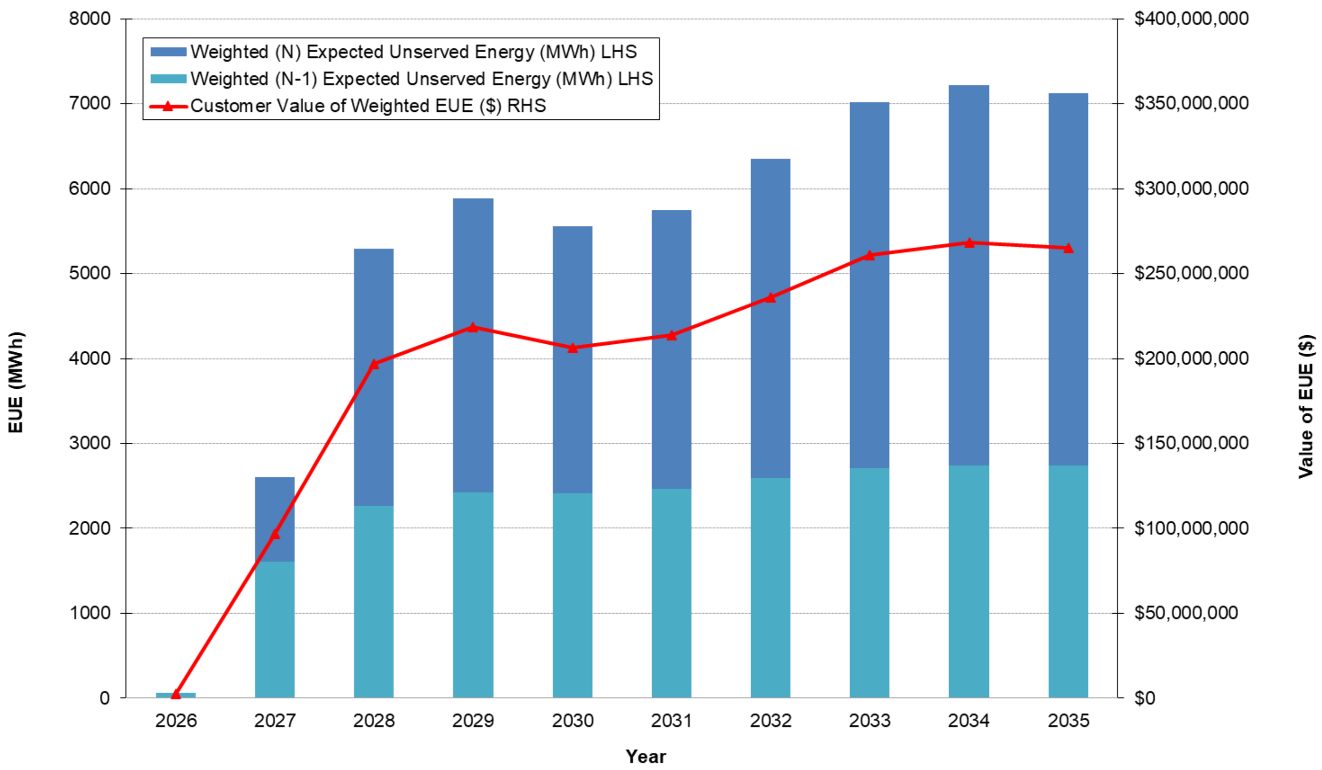


Table 2-3 summarises the value of the EUE from Table 2-2.

Table 2-3: Forecast EUE (MWh pa) at ATS-BLTS 66 kV (Do Nothing)

ATS-BLTS 66 kV EUE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	558.1	1,857	2,088	1,945	2,048	2,349	2,686	2,783	2,729
POE50 (N-1)	36.8	1,423	2,043	2,186	2,182	2,245	2,367	2,477	2,507	2,504
POE10 (N)	-	1,998	5,747	6,671	5,954	6,135	7,021	8,074	8,418	8,255
POE10 (N-1)	126.4	2,048	2,783	2,961	2,934	2,995	3,132	3,262	3,297	3,291
Total (Weighted[14])	**63.7**	**2,600**	**5,289**	**5,881**	**5,555**	**5,744**	**6,347**	**7,015**	**7,218**	**7,127**

Table 2-4: Forecast weighted value of EUE ($m real, 2025) at ATS-BLTS 66 kV (Do Nothing)

ATS-BLTS 66 kV EUE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	**2.4**	**96.7**	**196.7**	**218.7**	**206.6**	**213.6**	**236.0**	**260.9**	**268.4**	**265.0**

[14] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE.

3. Credible options assessed

This chapter identifies credible options that aim to address the identified need.

The potentially credible options considered to address the identified need for the supply area include:

- **Option 1** - do nothing (base case) continues to supply customers serviced by ATS-BLTS without any intervention (apart from load transfer options – i.e., the status-quo) to manage increasing EUE levels. It is used as a comparison case to which all other credible options will be compared, to identify the option that maximises the present value of net economic benefit. This is not considered a credible option going forward due to the associated EUE risk;

- **Option 2** - non-network or SAPS solution is to contract network support services within the distribution networks serviced by ATS-BLTS 66 kV, to reduce the net maximum demand on ATS-BLTS and address the identified need. Network support services could include services such as voluntary load reduction (e.g. demand response), aggregated distributed energy resources (e.g. virtual power plants), or larger-scale dispatchable embedded storage and/or generation resources;

- **Option 3** - establish a new BLTS North 66 kV bus group to address the identified need. This option involves leaving ATS-BLTS 66 kV as is, instead connecting the forecast major customer data-centre load to two new 220/66 kV 225 MVA transformers (B48) at BLTS in a new indoor bus group. There is provision to accommodate these transformers and indoor switchgear at BLTS; and

- **Option 4** - upgrade the existing ATS-BLTS 66 kV bus group to address the identified need. This option involves installing one new 220/66 kV 150 MVA transformer (B2) at BLTS 66 kV to complement the two existing 150 MVA units (with the new B2 transformer loaded radially but operated on an auto-close scheme to manage short circuit levels), retaining the 66 kV ties with ATS East to allow the 220/66 kV 150 MVA transformer at ATS East to remain in parallel with BLTS. There is provision to accommodate this new transformer at BLTS.

The PSCR flagged Option 4 as the likely preferred network option that maximises the net market benefits.

All network options would either increase the thermal capacity or reduce the demand on ATS-BLTS 66 kV. Table 3-1 below summarises the new thermal capacity ratings that would result from the three network options, compared to the base case in which no investment is undertaken.

Table 3-1: Thermal capacity ratings of each option (MVA)

Rating	Option 1	Option 3	Option 4
	ATS-BLTS 66 kV	BLTS North 66 kV	ATS-BLTS 66 kV
Summer (N)	508	530	678
Summer (N-1)	340	265	508
Winter (N)	579	588	762
Winter (N-1)	366	294	579

The different options will all result in lower EUE than in the base case, although the extent of the reduction varies due to the differences in the additional thermal capacity ratings they provide. JEN and Powercor consider that all options reduce EUE to a level consistent with the identified need for this RIT-T.

4. Submissions to the consultation

This chapter provides a summary of, and commentary on, the submissions to the PSCR consultation.

In September 2025, a project specification consultation report (**PSCR**) was published, being the first stage of this RIT-T process, which provided an opportunity for non-network providers to submit proposals for alternative solutions to address the identified need. During this period of consultation on the PSCR, no non-network proposals or submissions were received from interested stakeholders. Consequently, Option 2 from the PSCR (i.e., non-network or standalone power solution) is no longer considered a credible option for the purposes of this PADR in addressing the identified need.

Although the capital cost of the preferred network option is less than the second-stage trigger threshold of $54 million[15] for publication of a project assessment draft report, we are undertaking a second round of consultation for this RIT-T by publishing this PADR because of the material change in forecast demand since the publication of the PSCR.

[15] 2024 cost thresholds review for the Regulatory Investment Test | Australian Energy Regulator (AER).

5. Credible options costs and benefits

This chapter presents the scope, costs and benefits of the credible options.

5.1 Option 1 - Do nothing

The ”do-nothing” option involves continuing to supply customers serviced by ATS-BLTS without any intervention to manage EUE. This is expected to lead to significant supply interruptions and unserved energy under both “N” (system normal) and “N-1” (single contingency) conditions.

As detailed in Table 2-4, the total combined value of the EUE risk associated with the “Do nothing” option is forecast to increase from $2.4 million in 2026 to $196.7 million in 2027-28, to $265.0 million by 2034-35 (real, 2025).

In the context of this RIT-T, the “Do nothing” option is used as a base case to which all other credible options will be compared, to identify the option that maximises the present value of net economic benefit. Furthermore, since no incremental expenditure is implemented under the “Do nothing” option, the “Do nothing” option is considered a zero-cost and zero-benefit option.

5.2 Option 2 - Non-network or SAPS solution

Non-network or SAPS options could be contracted to provide network support services from within the distribution or sub-transmission networks serviced by ATS-BLTS 66 kV, to reduce the net maximum demand on ATS-BLTS (i.e., reduce the EUE) thereby addressing the identified need (at least in part).

Network support services could include services such as voluntary load reduction (demand response), aggregated distributed energy resources (virtual power plants), or larger-scale dispatchable (or standby) embedded storage and/or generation resources.

In September 2025, JEN and Powercor published the PSCR, being the first stage of this RIT-T process which provided an opportunity for non-network providers to submit proposals for alternative solutions to address the identified need.

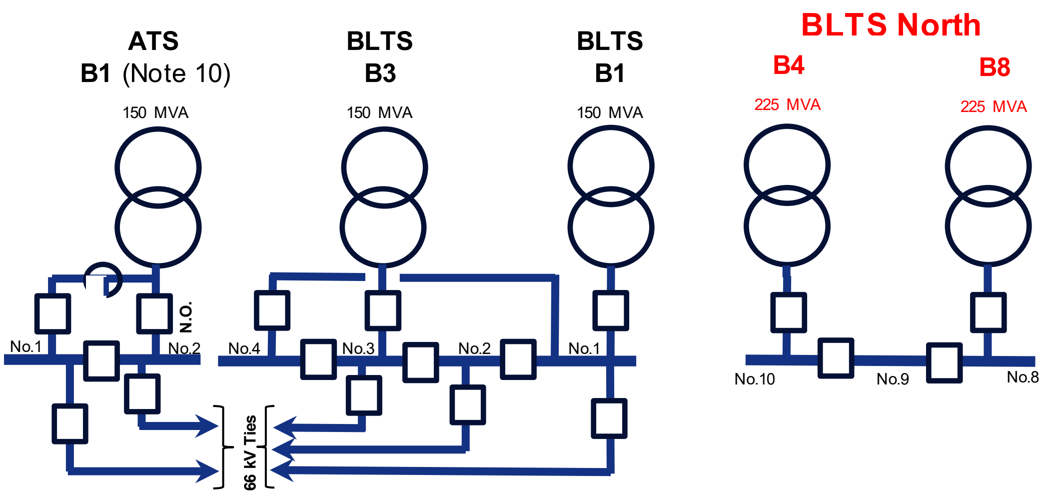
During this period of consultation on the PSCR, no non-network proposals or submissions were received from interested stakeholders.

Consequently, this option has been considered but not progressed on the basis that it is not a credible option for the purposes of addressing the identified need for this RIT-T.

5.3 Option 3 - Establish a new BLTS North 66 kV bus group (B48)

This option involves leaving ATS-BLTS 66 kV as is, instead connecting the forecast data-centre load to two new 220/66 kV 225 MVA transformers at BLTS (B48) in a new, separate indoor bus group designated (BLTS North 66 kV bus group), with the ability to expand to a third 225 MVA transformer in future. A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 5-1.

Figure 5-1: BLTS North 66 kV simplified single line diagram (Option 3)



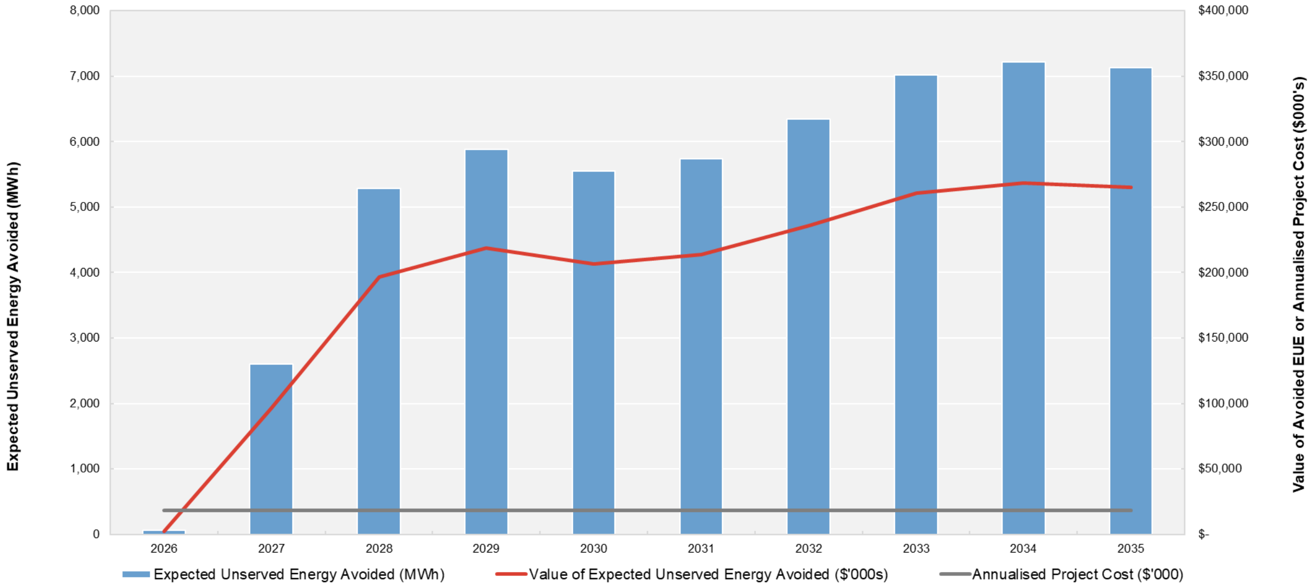
The scope of work required for this option includes:

- A new BLTS 66 kV indoor bus group designated BLTS North, comprising three fully-switched indoor buses (No.8, No.9, and No.10) with four feeder breakers and one transformer incomer (per bus) to be housed in a new 66 kV switch-room building, in a vacant location within the northern section of the BLTS site. There is no 66 kV electrical connection made between the existing 66 kV switchyard at BLTS and the new 66 kV indoor bus group.
- Install new B4 and B8 high impedance 220/66 kV 225 MVA transformers.
- Extend (towards the west), the 220 kV switchyard and buses to establish new Bays AA through to AF (inclusive).
- Connect B4 from 220 kV Bus No.4 in Bay AE, single switched via a new 220 kV circuit breaker using overhead 220 kV line, through to the new 66 kV Bus No.10 using 66 kV underground cable.
- Connect B8 from 220 kV Bus No.3 in Bay AE, single switched via a new 220 kV circuit breaker using underground 220 kV cable, through to the new 66 kV Bus No.8 using 66 kV underground cable.
- CTs, VTs, disconnectors, isolators, earth switches, surge arrestors, fittings and other equipment necessary to support the new equipment above.
- Earthworks (civil), earth-grid reinforcement, environmental works (bunding, noise mitigation, fire mitigation etc.), footings and structural works, reinstatements, and other works necessary to support the new equipment.
- Site and building services, auxiliary power supplies, conduits, protection, control and communications systems, and other systems necessary to support the new equipment.
- Interfacing of the new equipment with all existing systems at BLTS including setting and configuration modifications, with feeder unit protection relays that match remote end protection requirements.

- Labelling and drawing updates and update of all records associated with the installation of the new and modified equipment.
- Planning and building permit approvals for works within the BLTS site (if required).

The estimated capital cost of this network option is $210 million (real, 2025) and an ongoing operations and maintenance cost of $2.1 million per annum, which has a present value total cost of $179.4 million and an annualised cost of $18.5 million. Figure 5-2 identifies the optimal timing of Option 3 based on the avoided EUE risk and its annualised cost, being 2026-27.

Figure 5-2: Optimal timing based on avoided risks and annualised costs (Option 3)



Given this option has an estimated construction period of four years, the optimum timing is delayed by four years to summer 2030-31.

This option is not likely to have a material inter-network impact. This option considers relevant for this RIT-T, only those market benefits contemplated by Clause 5.15A.2 of the NER relating to changes in involuntary load shedding. Social licensing risks are considered minor for this option as it only involves work within an existing established brownfield substation in an industrial area, and establishment of an indoor 66 kV switchgear building. Localised community consultation and associated building and planning permitting would be undertaken as part of this option.

Table 5-1 lists the forecast EUE at ATS-BLTS 66 kV with Option 3 in service, based on its optimum timing.

Table 5-1: Forecast EUE (MWh pa) at ATS-BLTS 66 kV (Option 3)

ATS-BLTS 66 kV EUE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	558.1	1,857	2,088	1,945	-	-	-	-	-
POE50 (N-1)	36.8	1,423	2,043	2,186	2,182	0.1	0.1	0.2	0.2	0.2
POE10 (N)	-	1,998	5,747	6,671	5,954	-	-	-	-	-
POE10 (N-1)	126.4	2,048	2,783	2,961	2,934	1.9	2.3	2.8	3.0	2.9
Total (Weighted[16])	**63.7**	**2,600**	**5,289**	**5,881**	**5,555**	**0.6**	**0.8**	**1.0**	**1.0**	**1.0**

Table 5-2 lists the forecast value of EUE at ATS-BLTS with Option 3 in service, based on its optimum timing.

[16] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE.

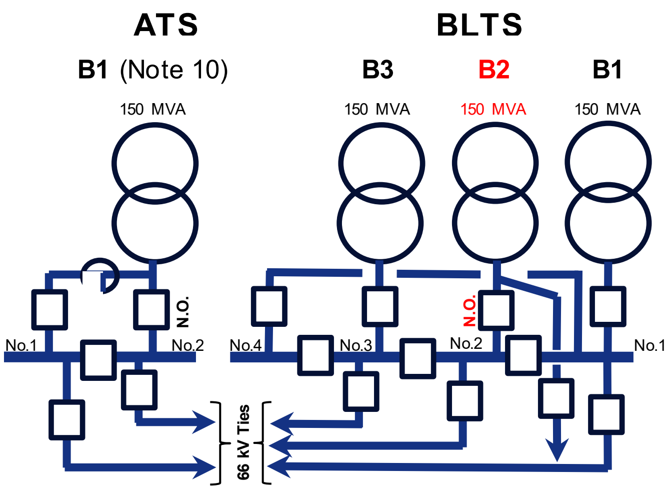
Table 5-2: Forecast value of EUE ($m, real 2025) at ATS-BLTS 66 kV (Option 3)

ATS-BLTS 66 kV EUE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	2.4	96.7	196.7	218.7	206.6	0.0	0.0	0.0	0.0	0.0

5.4 Option 4 - Upgrade the existing ATS-BLTS 66 kV bus group (B2)

This option involves installing one new 220/66 kV 150 MVA transformer at ATS-BLTS 66 kV to complement the two existing 150 MVA units, retaining the 66 kV ties with ATS to allow the 220/66 kV 150 MVA transformer at ATS to remain in parallel with BLTS. The new B2 transformer will be on a radial supply under system normal conditions and will operate as a standby (i.e., normally disconnected to the shared bus, with an auto-close scheme to manage short circuit levels under single contingency conditions). A simplified single line diagram of the 66 kV transmission connection assets for this option is shown in Figure 5-3.

Figure 5-3: Upgrade ATS-BLTS 66 kV simplified single line diagram (Option 4)



The scope of work required for this option includes:

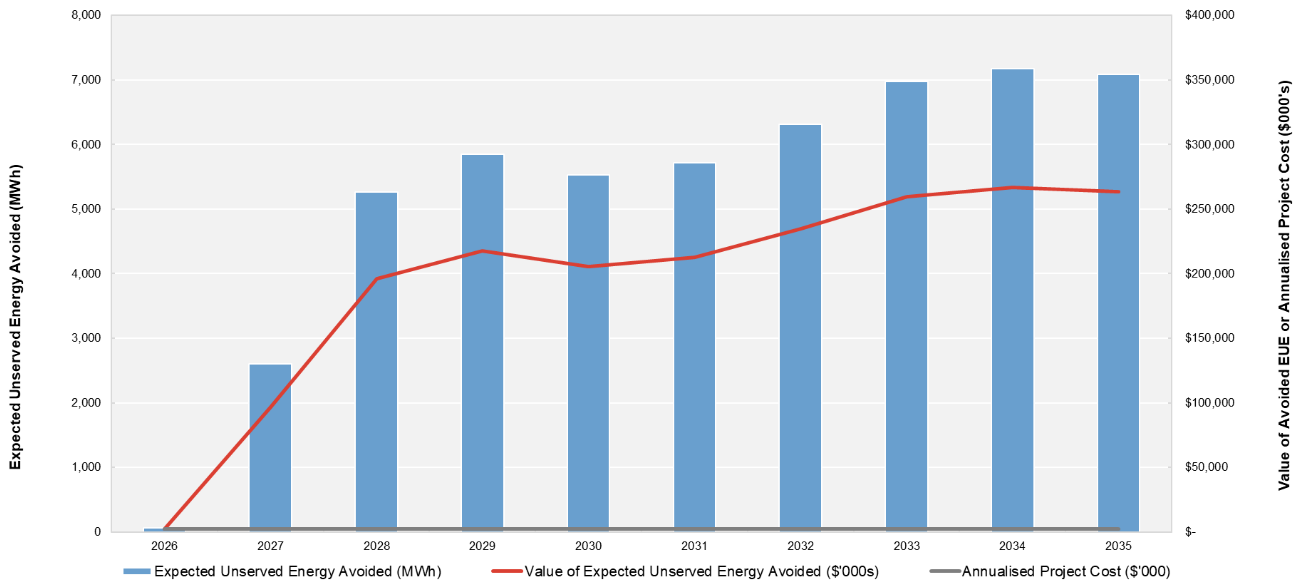
- Install one new B2 220/66 kV 150 MVA transformer at BLTS with impedances to match B1 and B3, with a neutral reactor and new 66 kV outdoor incomer circuit breakers.
- Connect B2 from the 220 kV B5 disconnector at BLTS, through to the existing 66 kV Bus No.2 via 66 kV underground cable.
- CTs, VTs, disconnectors, isolators, earth switches, surge arrestors, fittings and other equipment necessary to support the new equipment above.
- Earthworks (civil), earth-grid reinforcement, environmental works (bunding, noise mitigation, fire mitigation etc.), footings and structural works, reinstatements, and other works necessary to support the new equipment.
- Site and building services, auxiliary power supplies, conduits, protection, control and communications systems, and other systems necessary to support the new equipment.
- Interfacing of the new equipment with all existing systems at ATS and BLTS including setting and configuration modifications, with feeder unit protection relays that match remote end protection requirements.

- Labelling and drawing updates and update all records associated with the installation of the new and modified equipment.
- Planning and building permit approvals for works within the BLTS site (if required).

The estimated capital cost of this network option is $29.8 million (real, 2025) and an ongoing operations and maintenance cost of $0.3 million per annum, which has a present value total cost of $28.3 million and an annualised cost of $2.4 million.

Figure 5-4 identifies the optimal timing of Option 4 based on the avoided EUE risk and its annualised cost, being 2026-27.

Figure 5-4: Optimal timing based on avoided risks and annualised costs (Option 4)



Given this option has an estimated construction period of up to two years, the optimum timing is delayed by one year to summer 2027-28.

This option is not likely to have a material inter-network impact. This option considers relevant for this RIT-T, only those market benefits contemplated by Clause 5.15A.2 of the NER relating to changes in involuntary load shedding.

Social licensing risks are considered minor for this option as it only involves work within an existing established brownfield substation in an industrial area. Localised community consultation and associated building and planning permitting would be undertaken as part of this option.

Table 5-3 lists the forecast EUE at ATS-BLTS 66 kV with Option 4 in service, based on its optimum timing.

Table 5-3: Forecast EUE (MWh pa) at ATS-BLTS 66 kV (Option 4)

ATS-BLTS 66 kV EUE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
POE50 (N)	-	558.1	-	-	-	-	-	-	-	-
POE50 (N-1)	36.8	1,423	14.6	18.4	17.2	18.1	20.7	23.7	24.6	24.1
POE10 (N)	-	1,998	-	-	-	-	-	-	-	-
POE10 (N-1)	126.4	2,048	45.4	58.9	52.6	54.2	62.0	71.3	74.4	72.9
Total (Weighted[17])	**63.7**	**2,600**	**23.8**	**30.6**	**27.8**	**28.9**	**33.1**	**38.0**	**39.5**	**38.8**

[17] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE.

Table 5-4 lists the forecast value of EUE at ATS-BLTS with Option 4 in service, based on its optimum timing.

Table 5-4: Forecast value of EUE ($m, real 2025) at ATS-BLTS 66 kV (Option 4)

ATS-BLTS 66 kV EUE	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Weighted value of EUE	2.4	96.7	0.9	1.1	1.0	1.1	1.2	1.4	1.5	1.4

6. Assessment approach

This chapter details the assessment approach and assumptions that have been employed for this RIT-T assessment, as well as the materiality of specific categories of market benefits.

6.1 Assessment method

Consistent with the RIT-T NER requirements[18], *Cost Benefit Analysis guidelines*[19] and *RIT-T application guidelines*[20], JEN and Powercor have undertaken a cost-benefit analysis to evaluate and rank the net economic benefits of credible options. All options considered are assessed against a status-quo case, where no proactive capital investment to reduce the increasing baseline risks is made. The optimal timing of an investment option is the year when the annual benefits from implementing the option become greater than the annualised investment costs, subject to limitations in the construction lead time.

In planning the network, a probabilistic planning approach has been applied that balances reliability risk with the cost of potential risk mitigation options to identify the credible option that maximises the present value of net economic benefit (the preferred option).

The probabilistic planning approach estimates the service level risk of identified network limitations by combining:

- the impact (consequence) of network limitations under various conditions; and
- the likelihood of those limits being reached, considering the combined probabilities of relevant demand, generation and network availability forecasts eventuating, and the available load transfer capability.

Service level reliability risk is then estimated in monetary terms as the product of:

- EUE driven by the identified capacity limitations, in MWh per annum; and
- the locational VCR, in $/MWh.

Having identified the service level reliability risk, consideration is given to the estimated costs of credible options, and the reduction in reliability risk that each option provides, to identify whether the investment will result in a positive net market benefit.

The credible option that maximises the present value of net economic benefit is identified by:

- combining the avoided service level reliability risk of each credible option and that option's implementation and ongoing costs for each year; and
- identifying the credible option with the highest present value of total avoided service level reliability risk less the implementation, and ongoing operating and maintenance costs.

The optimal timing of this preferred option is identified by:

- calculating the preferred option's annualised implementation and ongoing costs; and
- selecting the year when the annual value of the avoided service level risk exceeds this annualised cost.

Application of the probabilistic planning approach often leads to the deferral of action that would otherwise proceed under a deterministic planning standard. Under a probabilistic network planning approach, conditions often exist where some of the load cannot be supplied under rare (but credible) conditions, such as at maximum demand or with a single network element out of service.

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[18] Regulatory investment test for transmission, Australian Energy Regulator, Version 3, 21 November 2024.

[19] Cost Benefit Analysis guidelines, Australian Energy Regulator, Version 3, 21 November 2024.

[20] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, Version 6, November 2024.

6.2 Input assumptions

The key assumptions used in this RIT-T apply to the:

- network asset ratings;
- forecast maximum demand;
- load transfer capability;
- annual load profile;
- network asset reliability (failure rates, repair times); and
- value of customer reliability.

6.2.1 Network asset ratings

The capability of the transmission connection assets at ATS-BLTS 66 kV is limited by the thermal rating of its three 220/66 kV 150 MVA transformers. Table 6-1 provides a summary of the capability of ATS-BLTS 66 kV for “N” and “N-1” conditions during summer and winter (maximum demand) seasons.

Table 6-1: ATS-BLTS 66 kV thermal capacity ratings (MVA)

ATS-BLTS 66 kV Rating	Existing
Summer (N)	508
Summer (N-1)	340
Winter (N)	579
Winter (N-1)	366

JEN and Powercor typically operate their networks using an N-1 probabilistic planning methodology which requires the maximum demand to exceed the N-1 rating (after load transfers, thereby resulting in EUE under single contingencies) before an augmentation can be considered.

6.2.2 Forecast maximum demand

The forecast maximum demand (**MD**) at ATS-BLTS 66 kV is specified according to its 10 per cent probability of exceedance (**POE10**) and its 50 per cent probability of exceedance (**POE50**) during summer and winter period[21], taking into consideration the major customer data-centre load forecasts.

Table 6-2 provides a summary of the forecast maximum demand for ATS-BLTS 66 kV during summer and winter (maximum demand) periods. Values in red indicate that the N-1 rating is exceeded. Values in **bold underlined red** indicate that N rating is exceeded.

[21] Victorian electricity demand is sensitive to ambient temperature. Maximum demand forecasts are therefore based on expected demand during extreme temperature that could occur once every ten years (POE10) and during average conditions that could occur every second year (POE50).

Table 6-2: Forecast maximum demand at ATS-BLTS 66 kV (MVA)

ATS-BLTS 66 kV MD	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer POE10	485	615	653	658	654	655	659	664	665	665
Winter POE10	488	627	641	646	648	653	660	665	666	667
Summer POE50	448	578	614	617	614	616	620	624	625	624
Winter POE50	466	605	619	623	626	631	637	642	644	644

ATS-BLTS 66 kV is expected to exceed its N rating by 2027.

Figure 6-1 shows the POE10 and the POE50 forecasts of maximum demand for ATS-BLTS 66 kV during summer periods relative to its capacity.

Figure 6-1: Summer period maximum demand forecasts for ATS-BLTS 66 kV

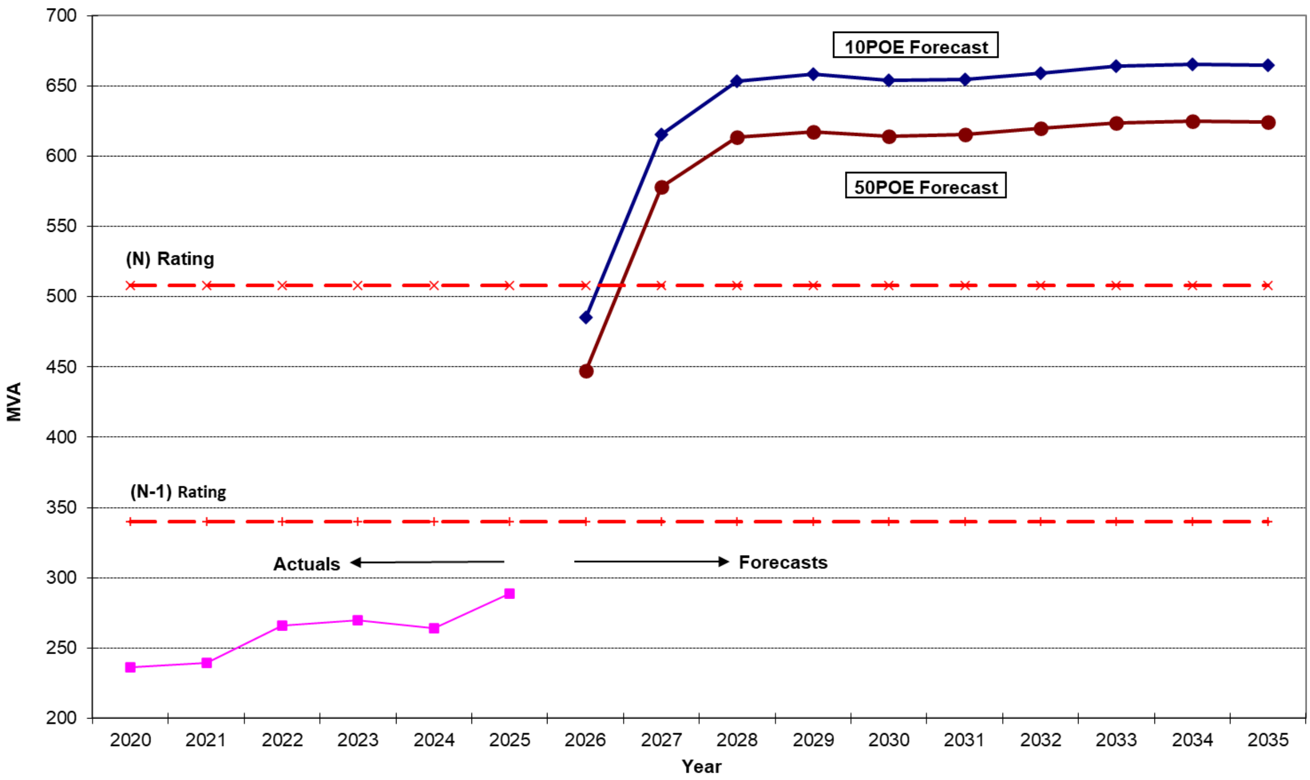
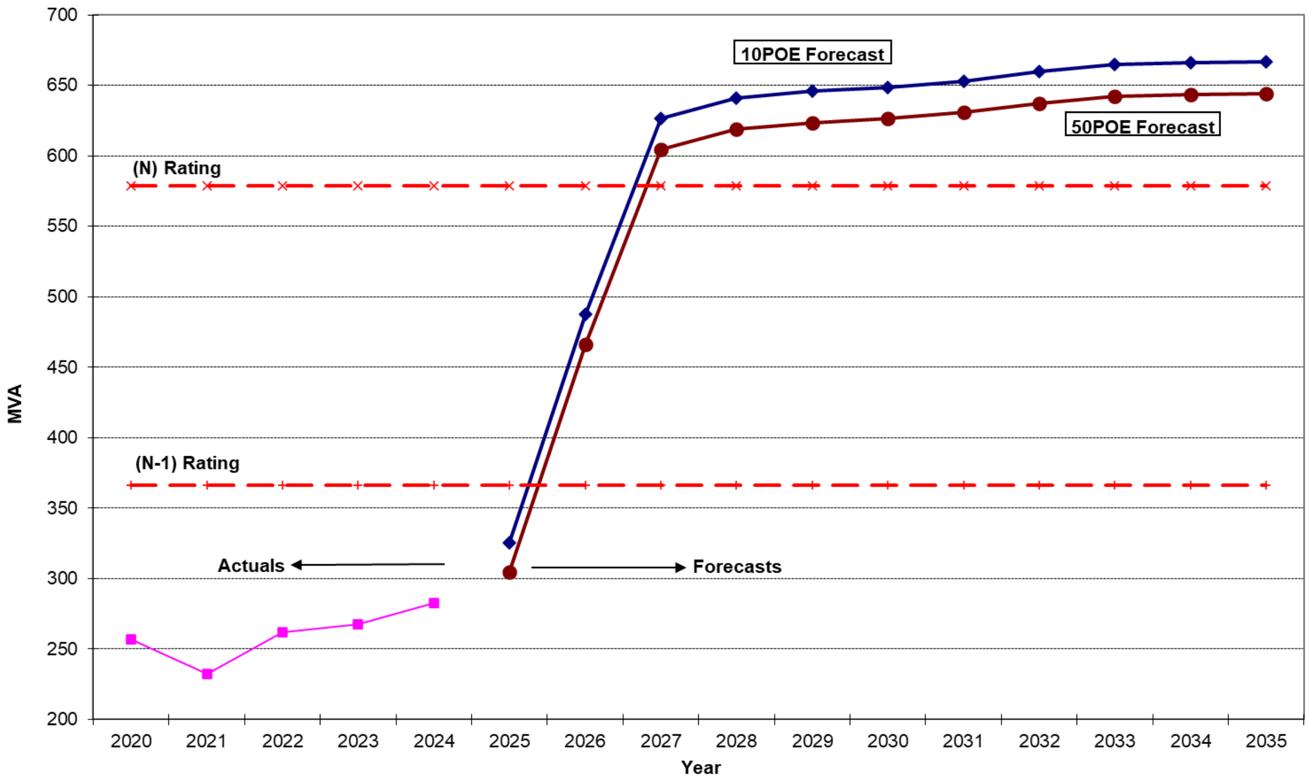


Figure 6-2 shows the POE10 and the POE50 forecasts maximum demand for ATS-BLTS 66 kV during winter periods relative to its capacity.

Figure 6-2: Winter period maximum demand forecasts for ATS-BLTS 66 kV



6.2.3 Load transfer capability

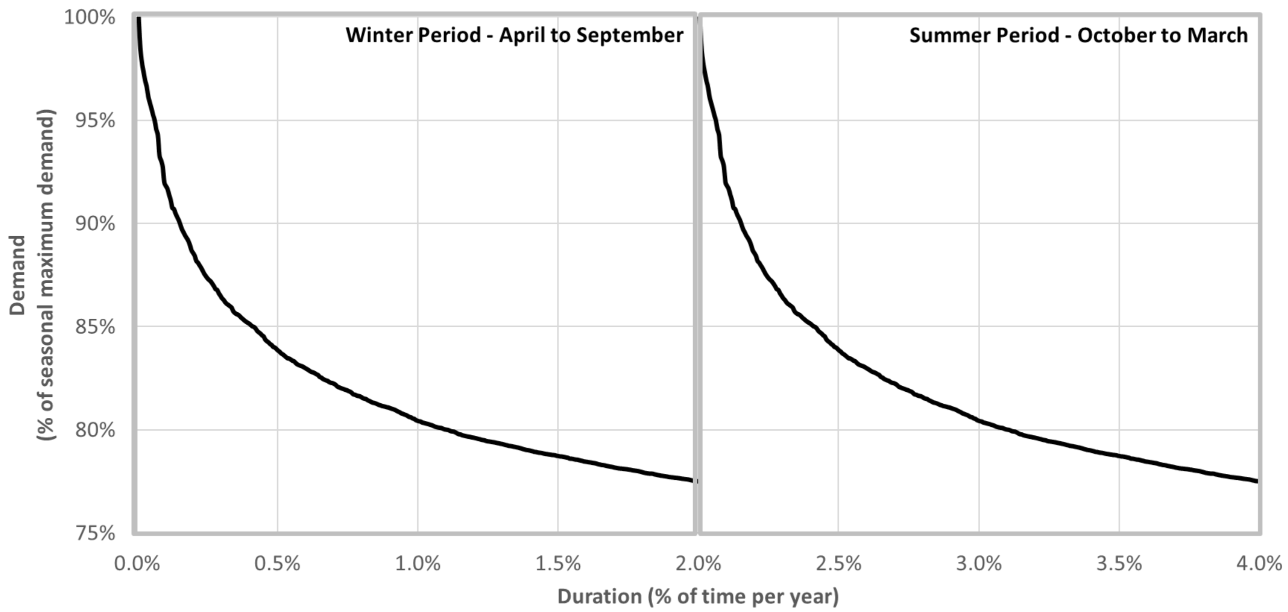
There is the capacity to transfer 8.0 MVA (Powercor) and 5.0 MVA (JEN) of load at BLTS to other terminal stations (post-contingent) via the distribution feeder network at peak demand in 2025. This transfer capacity is expected to reduce by 4.5 MVA per annum over the 10-year planning horizon due to growth in the area.

There are also some demand management arrangements in place (totalling 35 MVA) to mitigate risk in 2026-27.

6.2.4 Annual load profile

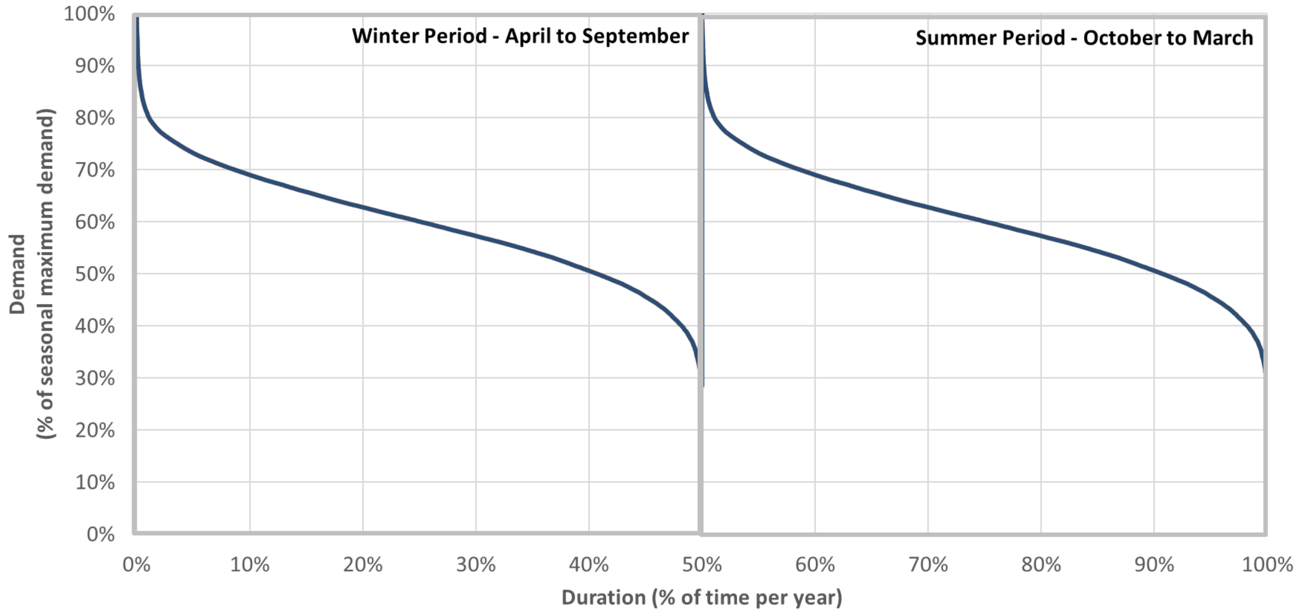
The load-duration curves for ATS-BLTS 66 kV are shown in Figure 6-3 at times of peak demand periods in winter and summer seasons.

Figure 6-3: Load-duration profile for ATS-BLTS 66 kV at peak demand



The shape of the curves are strongly influenced by the coincidence of extreme ambient temperature on working weekdays and the number of times this occurs in any one year. This is illustrated in Figure 6-4 for the full year showing the profiles for winter and summer seasons.

Figure 6-4: Annual load-duration profile for ATS-BLTS 66 kV

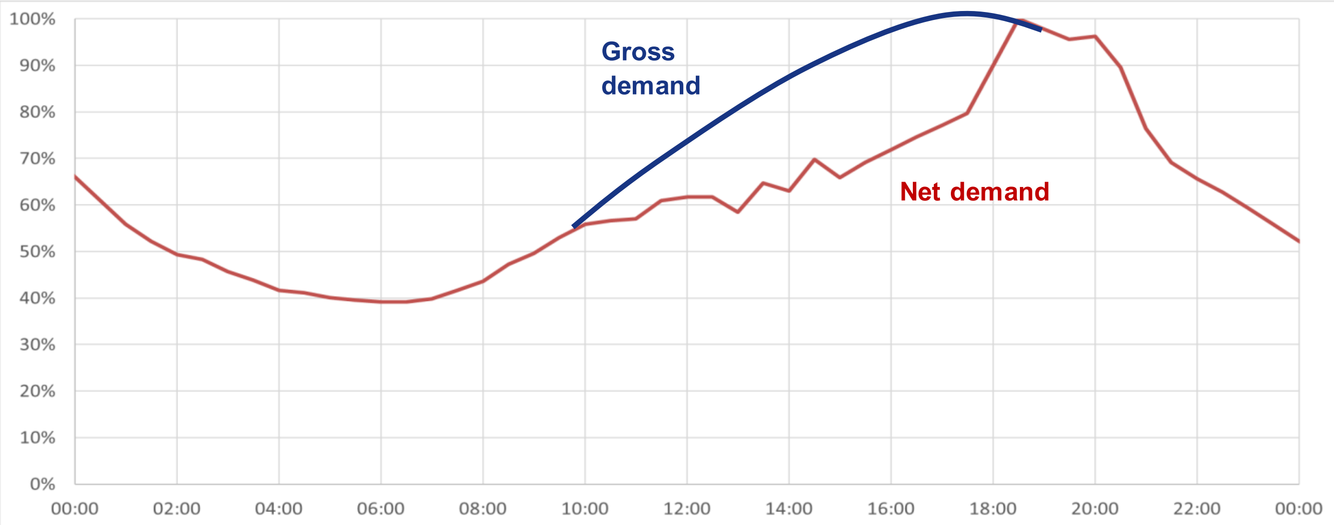


A total of 124 MW of embedded generation capacity is installed on the sub-transmission and distribution systems connected to ATS-BLTS. It consists of:

- 78 MW of solar PV systems that are smaller than 1 MW, which includes 45 MW in the Powercor distribution system and 33 MW in the JEN distribution system; and
- 46 MW capacity of embedded generators greater than 1 MW, which includes 40 MW in the Powercor distribution system and 5.7 MW in the JEN distribution system.

The typical net daily load profiles at ATS-BLTS 66 kV during the summer season are shown in Figure 6-5.

Figure 6-5: Daily load profile for ATS-BLTS 66 kV (summer peak demand)



6.2.5 Network asset reliability

Table 6-3 provides a summary of the ATS-BLTS 220/66 kV transformer reliability information used in the EUE analysis.

Table 6-3: ATS-BLTS 220/66 kV transformer reliability information

Transformer Reliability Quantity	Value	Description
Major forced outage rate (failure rate)	1.0% per annum	A major outage is expected to occur once per 100 transformer-years. In a population of 100 terminal station transformers, expect one major failure of any one transformer per year.
Weighted average of major outage duration (repair time)	2.65 months	On average, 2.65 months is required to return the transformer to service, during which time the transformer is not available for service.
Expected transformer unavailability due to a major outage per transformer-year	0.22%	On average, each transformer would be expected to be unavailable due to major outages for 0.01 x 2.65/12 = 0.22% of the time, or 19 hours per year.

6.2.6 Value of customer reliability

The cost of EUE is calculated using a VCR, which is an estimate of the value electricity consumers put on having a reliable electricity supply.

The locational VCR values have been applied based on the escalated estimates in the AER's *Values of Customer Reliability Review* published in December 2025[22].

Specifically, applying the AER's VCR estimates for different sectors (i.e., residential, commercial, industrial and agricultural) to terminal station level recent energy composition data, we have calculated the following VCRs for ATS-BLTS 66 kV (presented in Table 6-4), with the aggregated value for ATS-BLTS 66 kV being $37,190 per MWh.

[22] AER 2025 published escalated VCRs. Climate zone 6 applies at ATS-BLTS.

Table 6-4: ATS-BLTS 66 kV value of customer reliability

Sector	AER VCR ($/MWh, 2025)	Energy consumption	Weighted VCR ($/MWh)
Residential	51,106	12.2%	6,258
Agricultural	23,098	0.0%	0
Commercial	35,700	54.6%	19,502
Large Business[23]	34,361	21.5%	7,380
Industrial	34,766	11.6%	4,050
Composite		**100%**	**37,190**

6.3 Assessment parameters

The key parameters used in this RIT-T for the cost-benefit assessment include:

- assessment period;
- discount rate; and
- option cost estimations.

6.3.1 Assessment period

For this RIT-T we have undertaken the NPV analysis over a ten-year period, from 2026 to 2035. We consider that the length of this assessment period accounts for 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 the expected demand growth within the supply area intended to be addressed by the credible options in this RIT-T.

The relatively short time period proposed to be used for the assessment reflects the possibility that the current options only address the immediate need (due to the uncertainty of the demand forecasts) and that a further augmentation of ATS-BLTS may be needed in future when the data-centre load actually materialises, in which case another RIT-T will be initiated.

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

6.3.2 Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. We use the commercial discount rate in AEMO's *2025 Inputs, Assumptions and Scenarios Report* (**IASR**) [24] being 7.0 per cent.

The discount rate used in this RIT-T for the low bound sensitivity test is a regulatory discount rate of 4.69 per cent. For the high bound sensitivity test we use a 10.0 per cent discount rate consistent with the IASR.

[23] Greater than 10 MW.

[24] 2025 Inputs, Assumptions and Scenarios Report, Table 31, Australian Energy Market Operator (AEMO), August 2025.

6.3.3 Approach to cost estimation for network options

The costs for each option have been calculated by AusNet Transmission Group, JEN and Powercor's cost estimation teams based on recent similar project costs and scope. Costs are expected to be within ±30 per cent of the actual cost.

The costs presented in this RIT-T include escalations, overheads, financing charges and management reserve (contingency risk). All cost estimates are escalated to real 2025 dollars based on the information available at the time of preparing this report. Overheads and financing charges comprise approximately 10.7% of the total costs, and contingency risk of 5.8%.

Social license costs have been included but are relatively small for this RIT-T because the options only involve work within an existing established brownfield substation in an industrial area. The importance of allocating appropriate costs to social licence activities is supported by established best practice in regulated electricity infrastructure delivery, as articulated in *Powercor's commitment on engagement and land access* document[25]. The document clearly recognises that effective, genuine stakeholder engagement is fundamental to gaining and maintaining a social licence to operate, particularly where projects impact landowners and local communities. Social licence is not incidental to project delivery; it is built through early, sustained engagement, collaboration, and the resolution of community concerns, with the objective of minimising negative impacts and maximising shared benefits. Our approach demonstrates that social licence activities require structured processes, dedicated engagement teams, negotiated land access arrangements, complaints handling mechanisms, and compliance with formal regulatory instruments. These measures are consistent with contemporary expectations of trust, credibility and legitimacy placed on regulated network service providers.

Ongoing operating and maintenance costs are included in the assessment annually from the year after the capital investment at a level of 1 per cent of the capital cost per annum for brownfield sites and 0.5 per cent for greenfield sites.

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.

6.4 Materiality of market benefits

6.4.1 Material classes of market benefits

NER clause 5.15A.2(b)(4) sets out the classes of market benefits that must be considered in a RIT-T. The market benefits likely to be material are:

- **Changes in involuntary load shedding** – the proposed approach to calculate the benefits is therefore in reducing the level of EUE as set out in section 6.1, that is the avoided risk of deteriorating reliability from involuntary load shedding, taking into account changes in load transfer capability.

We consider that changes in avoided EUE is the only class of market benefit that is material to the RIT-T assessment.

6.4.2 Market benefits not considered material

The following classes of market benefits are unlikely to be material for any option considered in this RIT-T:

- **Changes in fuel consumption arising through different patterns of generation dispatch** –the network is not normally interconnected to the extent that asset failures cannot be remediated by re-dispatch of generation, and the wholesale market impact is expected to be the same.

[25] "Powercor commitment on engagement and land access", Powercor Australia.

- **Changes in voluntary load curtailment** – no non-network proposals were submitted during the consultation on the PSCR, therefore this is not considered to be a material market benefit.
- **Changes in costs for parties, other than the RIT-T proponent** – there is no other known investment, either generation or transmission, that will be affected by any option considered.
- **Differences in the timing of expenditure** – the timing of other unrelated expenditure is not expected to be 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.
- **Change in network losses** – changes in network losses are considered negligible in comparison to other market benefits considered in this RIT-T and unlikely to be a material class of market benefits for any of the credible options.
- **Changes in ancillary services costs** – the options are not expected to impact on the demand for and supply of ancillary services.
- **Changes in Australia's greenhouse gas emissions** – changes in greenhouse gas emissions from changes in network losses, renewable energy generation curtailment, or levels of SF_6 emissions from high-voltage switchgear, are considered negligible and unlikely to be a material class of market benefits for any of the credible options.
- **Competition benefits** – there is no competing generation affected by the limitations and risks being addressed by the options considered for this RIT-T.
- **Option value** – this is likely to arise where there is uncertainty regarding future outcomes or in the information that is currently available, and the credible options are sufficiently flexible to respond to change. We expect that the costs of modelling option value will be disproportionate to any benefits and that there will be limited option value outside of anything captured in the scenario analysis.

6.5 Sensitivity studies

The robustness of the investment decision is tested using the range of input assumptions described in Table 6-5. This analysis varies the assumptions used for the base case as detailed in section 6.2

Table 6-5: Input assumptions used for the sensitivity studies

Parameter	Lower bound	Base case	Higher bound
Capital and operating costs	70% of the option's total cost	100% of the option's total cost	130% of the option's total cost
Forecast maximum demand	90% of base case maximum demand	100% of base case maximum demand	105% of base case maximum demand
Asset failure rate	80% of base	100% of base	120% of base
Value of customer reliability	80% of AER 2025 VCRs - site specific for ATS-BLTS	100% of AER 2025 VCRs - site specific for ATS-BLTS	120% of AER 2025 VCRs - site specific for ATS-BLTS
Discount rate	4.69% - regulatory discount rate	7.00% - commercial discount rate (IASR)	10.00% - (IASR)
Asset life	20 years	45 years	60 years

6.6 Scenario modelling to address uncertainty

The RIT-T analysis is required to incorporate several different reasonable scenarios, which are used to estimate the benefits and rank options. The number and choice of reasonable scenarios must be appropriate to the credible options under consideration and reflect any variables or parameters that are likely to affect the ranking or sign of the net economic benefit of any credible option.

The assessment for this PADR was conducted under three future-state scenarios by choosing the parameters in Table 6-5 with high uncertainty, as follows:

- **central scenario** – adopting the base case assumptions in Table 6-5;
- **low scenario** – adopting lower bound demand, failure rates and VCR; and
- **high scenario** – adopting higher bound demand, failure rates and VCR.

These are plausible scenarios which reflect different assumptions about the future energy landscape and other factors that are expected to affect the relative market benefits of the options considered. In Table 6–8, the reasoning for selecting these parameters is provided as well as the weighting applied to each future-state scenario to reflect the likelihood of each scenario, based on currently available information.

Table 6-6: Parameters with high uncertainty used for scenario modelling

Parameter	Low scenario	Central scenario	High scenario	Reasoning
	25%	**50%**	**25%**	
Forecast maximum demand	Lower Bound	Base Case	Higher Bound	Over the last decade there was significant uncertainty in forecasting maximum demand. Factors including economic growth, retail electricity prices, gas electrification, and uptake of distributed energy resources (including rooftop solar, batteries and electric vehicles) have contributed to the uncertainty. Uncertainty is expected to remain high over the planning horizon in each of these areas. An equal weighting has been applied to high and low scenarios. A higher weighting has been applied to the central scenario as we only have committed block load customers included in the forecast demand.
Asset failure rate	Lower Bound	Base Case	Higher Bound	Transformers have a very high reliability and long technical life, meaning their forced outage rates are highly uncertain, being dependent on a range of technical and environmental operating factors. With increasing condition monitoring, changes in technology and climate change, historical failure rates may not be reflective of future performance.
Value of customer reliability	Lower Bound	Base Case	Higher Bound	Variability in the valuation of customer reliability between VCR surveys demonstrates a need to consider future changes in the VCR in the analysis. Furthermore, with the changes in the way customers are using electricity and adopting storage solutions, this is likely to impact the value that customers place on supply reliability.

7. Options assessment

This chapter presents the results of the NPV analysis for each option and identifies the proposed preferred option and its optimal timing, along with scenario and sensitivity analysis results to confirm the robustness of the proposed preferred option to credible changes in assumptions.

7.1 Gross market benefits

All the options considered in this RIT-T assessment address the identified need to varying extents resulting in differing levels of gross benefits relative to the "Do nothing" base case. The estimated present value of gross benefits of each option is presented in Table 7-1 based on their optimal timing.

Table 7-1: Calculated present value of gross benefits relative to base case ($ million, real 2025)

Option	Low scenario	Central scenario	High scenario
1	0.0	0.0	0.0
3	127	721	1,793
4	210	1,190	2,952

7.2 Capital and operating costs

The estimated present value of capital, operations and maintenance costs of each option relative to the "Do nothing" base case is presented in Table 7-2 based on their based on their optimal timing.

Table 7-2: Calculated present value of capital and operating costs relative to base case ($ million, real 2025)

Option	Low scenario	Central scenario	High scenario
1	(0.0)	(0.0)	(0.0)
3	(179.4)	(179.4)	(179.4)
4	(28.3)	(28.3)	(28.3)

7.3 Present value of net economic benefits

The estimated present value of net economic benefits of each option relative to the "Do nothing" base case, being the present value of gross benefits minus the present value of capital and operating costs, is presented in Table 7-3 based on their optimal timing.

Table 7-3: Calculated present value of net economic benefits relative to base case ($ million, real 2025)

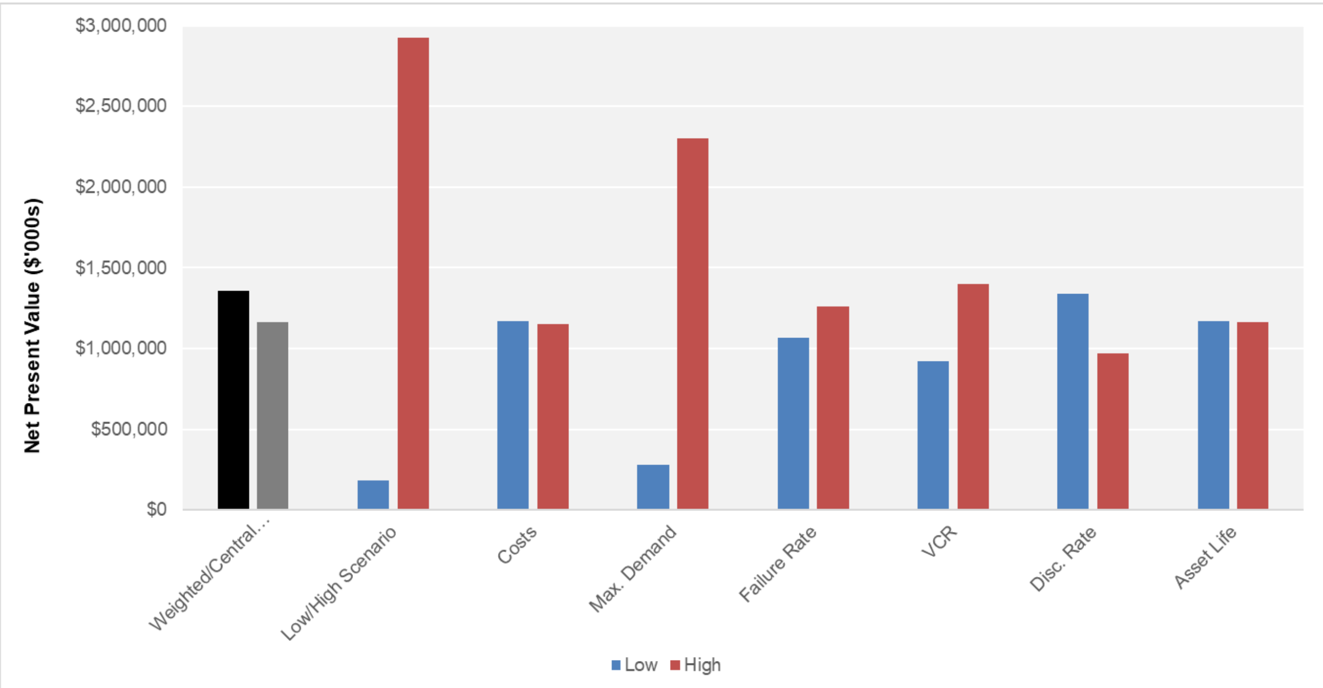
Option	Low scenario	Central scenario	High scenario	Weighted scenario	Ranking
	25%	50%	25%	100%	
1	0	0	0	0	3
3	(52)	542	1,614	662	2
4	182	1,162	2,924	1,358	1

7.4 Proposed preferred option

Given Option 4 maximises the present value of net economic benefits under the weighted scenario and that net benefit remains positive under all credible scenarios, we recommend Option 4 as the proposed preferred option with an optimum timing being 2027-28. Option 4 satisfies the requirements of the RIT-T at this draft stage.

The robustness of the proposed preferred option's net economic benefits to credible variations in key parameters (in Table 6–7), is demonstrated in the sensitivity study results of Figure 7–1. Under all credible sensitivities, the net present value of benefits remains positive for Option 4.

Figure 7-1: NPV sensitivity analysis of the proposed preferred option ($ thousand, real 2025)



7.5 Optimal timing of the proposed preferred option

This section identifies and tests the robustness of the optimal timing of Option 4 for different assumptions of key parameters as detailed in Table 6-5. The changes in timing away from the optimal timing of 2027-28 for each of the sensitivities is presented in Table 7-4, accounting for a two-year construction time.

Table 7-4: Sensitivity of the optimal timing with respect to variation of key parameters

Parameter	Lower Bound	Higher Bound
Capital and operating costs	No change	No change
Forecast maximum demand	No change	No change
Asset failure rate	No change	No change
Value of customer reliability	No change	No change
Discount rate	No change	No change
Asset life	No change	No change

The timing of the proposed preferred option is robust, remaining unchanged in all sensitivities.

8. Draft conclusion and next steps

This chapter presents the conclusions of the PADR, details of the proposed preferred option, and next steps.

8.1 Draft conclusion

The cost-benefit economic evaluation assessment undertaken for this PADR has concluded that the proposed preferred option to address the identified need for this RIT-T is Option 4. It is the proposed preferred option in accordance with NER clause 5.16.1(b) because it is the credible option that maximises the net present value of the net economic benefit. It therefore satisfies the RIT-T.

The proposed preferred option is found to have positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver $1,358 million in present value net economic benefits over the 10-year analysis period.

The proposed preferred option involves an upgrade of the existing ATS-BLTS 66 kV bus group with a new 220/66 kV 150 MVA transformer (B2) to increase the thermal capacity of the ATS-BLTS transmission connection assets and address the identified need. There is provision to accommodate this transformer at BLTS. The estimated capital cost of this option is $29.8 million (real, 2025) with annual operating and maintenance costs relating to this investment of approximately $0.3 million, with an optimum timing of 2027-28. This timing is based on the construction lead time required for this option.

8.2 Next steps

JEN and Powercor invite written submissions and enquiries on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "**Altona-Brooklyn Terminal Station Capacity Constraint RIT-T**" and directed to both:

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Data Centre Network Planning Leader

PlanningRequest@jemena.com.au

and

Richard Robson (Powercor)

Manager Sub-transmission Planning and Major Connections

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The consultation on this PADR is open for 6 weeks. Submissions are due on or before 18 September 2026. Submissions will be published on the AEMO, JEN and Powercor websites. If you do not wish for your submission to be published, please clearly stipulate this at the time of lodging your submission.

Following conclusion of the PADR consultation period, JEN and Powercor will, having regard to any submissions received on the PADR, prepare and publish a PACR including:

- a summary of, and commentary on, the submissions on the PADR;
- the matters detailed in the PADR; and
- confirmation of the preferred option to meet the identified need.

Publication of that report conclude consultation on this RIT-T.

JEN and Powercor intend to publish the PACR by the end of 2026.

9. Appendix A – RIT-T compliance checklist

This appendix sets out a checklist in Table 9-1 which demonstrates the compliance of this PADR with the requirements of clause 5.16.4(k) of the NER, version 243.

Table 9-1: PADR RIT-T compliance checklist

A RIT-T proponent must prepare a report which must include:	Chapter
(1) a description of each credible option assessed;	Chapter 3
(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Chapter 4
(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	Chapter 5
(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Chapter 6
(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Chapter 6
(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);.	Chapter 6
(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Chapter 7
(8) the identification of the proposed preferred option;	Chapter 7
(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i)details of the technical characteristics; (ii)the estimated construction timetable and commissioning date; (iii)if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv)a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission;	Chapter 8
(10) if each of the following apply to the RIT-T project: (i)the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and (ii)AEMO is not the sole RIT-T proponent, the RIT reopening triggers applying to the RIT-T project;	Not applicable