AusNet

Jemena
bringing energy to life

Maintaining supply reliability in the South Morang supply area

RIT-T Project Assessment Draft Report

Thursday, 9 April 2026

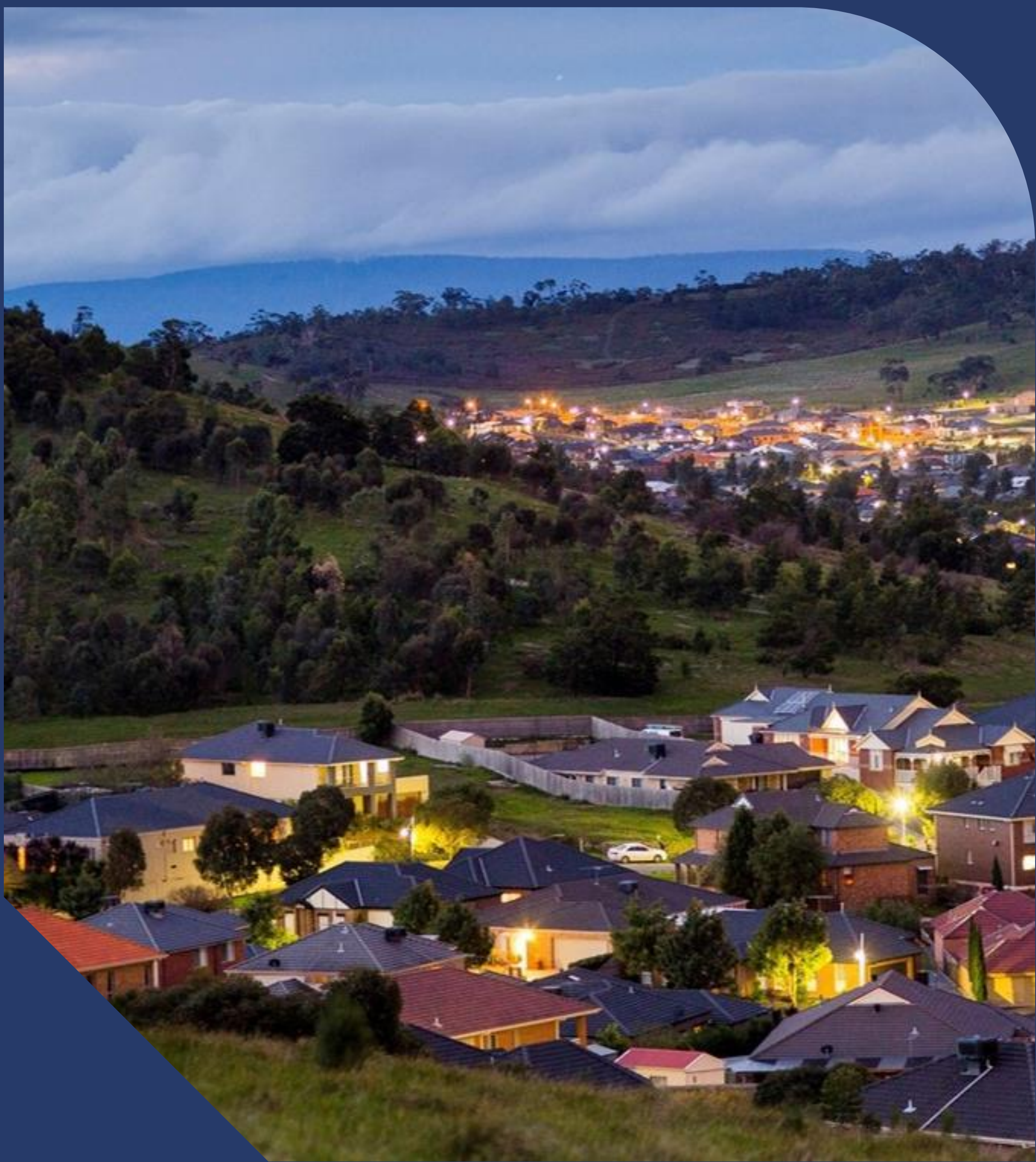


Table of contents

Important notice

Purpose

AusNet Electricity Services Pty Ltd (AusNet) and Jemena Electricity Network (JEN) have prepared this project assessment draft report (PADR) in accordance with clause 5.16.4 of the National Electricity Rules (NER). This PADR is the second stage of the South Morang Supply Area Regulatory Investment Test for Transmission (RIT-T) consultation process, relating to maintaining supply reliability within the South Morang supply area.

Disclaimer

Executive summary

AusNet Electricity Services Pty Ltd (AusNet) and Jemena Electricity Network (JEN) are regulated Victorian Distribution Network Service Providers (DNSPs) that supply electricity distribution services to more than 845,000 and 384,000 customers, respectively. AusNet's electricity distribution network services eastern regional Victoria and the outer northern and eastern Melbourne metropolitan area. JEN's electricity distribution network services Melbourne's northern and western greater metropolitan area.

As expected by our customers and required by the various regulatory instruments that we operate under, AusNet and JEN aim to maintain service levels at the lowest possible cost for our customers. To achieve this, we assess options and develop plans that aim to 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 South Morang Terminal Station (SMTS) and as such, is subject to a regulatory investment test for transmission (RIT-T). SMTS supplies electricity to parts of the AusNet (the lead proponent of this RIT-T) and JEN electricity distribution networks.

AusNet and JEN are undertaking a RIT-T process to evaluate options to maintain reliability of supply in the South Morang supply area. Options investigated in this RIT-T aim to mitigate the risk of a deterioration in power supply reliability from the transmission connection assets at SMTS that service the South Morang supply area.

Our RIT-T analysis shows that it is no longer economically viable to continue to service peak electricity demand using the existing installed capacity of transmission connection assets at SMTS. The supply reliability risk (quantified by the expected unserved energy (EUE)), has increased to a level where investment to increase capacity for the area offers a more economical alternative to the status-quo, based on the value that consumers place on supply reliability.

On 27 June 2025, AusNet and JEN published the project specification consultation report (PSCR), which represented the first stage of this RIT-T process in accordance with clause 5.16 of the National Electricity Rules (NER)[1] and section 4.2 of the RIT-T Application Guidelines[2]. The PSCR assessments observed that the network option, to install a third 225 MVA 220/66 kV transformer (and associated switchgear) at SMTS would likely be the preferred network option.

During the PSCR consultation period, no non-network proposals or submissions were received from interested stakeholders. AusNet and JEN have now prepared this PADR in accordance with clause 5.16 of the NER and section 4.3 of the RIT-T Application Guidelines. The PADR is the second stage of the RIT-T process and incorporates the assessment results of the credible options, providing draft conclusions on the proposed preferred option for addressing the identified need in the South Morang supply area.

This PADR proposes the preferred option and its timing, being the installation of a third 225 MVA 220/66 kV transformer at SMTS at an estimated capital cost of $48.63 million (real, 2025) by 2028-29, as the option that satisfies the requirements of the RIT-T.

Identified need

The identified need for this RIT-T is to maintain electricity supply reliability and mitigate forecast increases in expected unserved energy (EUE) for those customers supplied from SMTS.

SMTS is owned and operated by AusNet Transmission Group and is in South Morang in Melbourne's north-eastern suburbs in Victoria. It serves as the main transmission connection point for distribution of electricity to customers to those parts within the AusNet and JEN distribution service areas incorporating the South Morang supply area.

SMTS supplies electricity to more than 161,523 customers[3], with residential customers consuming 45.1 per cent of the total annual energy supplied from SMTS, closely followed by commercial customers at 43.7 per cent. The geographic coverage of the area supplied by the transmission connection assets at SMTS spans from Seymour, Kilmore, Kalkallo, Kinglake and Rubicon in the north to Mill Park in the south, and from Doreen and Mernda in the east to Somerton and Craigieburn in the west.

Electricity demand in the SMTS service area has been amongst the fastest growing regions in Victoria and SMTS is reaching its full capacity soon. The summer peak demand at SMTS increased by 211 MVA between 2011-12 and 2024-25, equivalent to an average annual growth rate of 16 MVA or 5.2 per cent. In 2024-25 the summer maximum demand reached 434.8 MVA, which is the historical maximum for this terminal station.

SMTS currently has two 225 MVA 220/66 kV transformers and the summer cyclic rating of SMTS with all plant in service is 538 MVA at 35°C and 519 MVA at 40°C. This rating is expected to be exceeded in 2028-29 for the POE10, and in

[1] National Electricity Rules, version 243, Australian Energy Market Commission (AEMC), 2025.
[2] Regulatory investment test for transmission Application guidelines, Australian Energy Regulator, November 2024.
[3] 37,268 JEN customers, and 124,255 AusNet customers.

2030-31 for the POE50. The summer cyclic rating of SMTS with one of its two transformers out of service, reduces to 269 MVA at 35°C and 259 MVA at 40°C and this rating is expected to be exceeded every year from now.

The maximum demand growth in the SMTS supply area is primarily due to the following:

- staged development of residential estates and other residential subdivisions; commercial developments, such as shopping centres, childcare centres, schools, medical centres and retail hubs, associated with new large residential developments and large customer loads; and
- electrification of gas and transport sectors of society, associated with the energy transition.

Due to the strong demand growth in the area and the high utilisation of SMTS at maximum demand, the level of EUE resulting from capacity limitations at SMTS is forecast to grow, deteriorating 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 (SAPS) solution, is expected to result in a net economic benefit.

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

Potential credible options

The PSCR presented options designed to address the identified need for continuing to reliably meet the electricity demand requirements of customers within the South Morang supply area. The credible options considered were:

- Option 1 - Do Nothing;
- Option 2 - Non-network or SAPS solution;
- Option 3 - Install third 220/66 kV transformer at SMTS;
- Option 4 - Install third and fourth 220/66 kV transformers at SMTS;
- Option 5 - Establish two new 22 kV feeders to offload SMTS (followed by Option 3);
- Option 6 - Establish a new 220/66 kV Donnybrook terminal station (DBTS).

All the network options identified in the PSCR are assessed in this PADR.

No non-network proposals were received during the South Morang supply area RIT-T PSCR consultation in June 2025; therefore Option 2 is not considered to be a credible option for the purposes of this PADR.

Assessment approach

AusNet and JEN applied the AER's RIT-T Application Guidelines 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 that involve variations of assumptions around the values used in the base case. None of the options considered propose to make a material impact on wholesale market costs and hence no market simulation studies have been conducted for this RIT-T.

Options assessment and draft conclusion

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.

A cost-benefit economic evaluation assessment was undertaken for this PADR, and a summary of the net present value analysis for each option and each scenario is provided in Table 1.

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

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

OPTION	LOW SCENARIO	CENTRAL SCENARIO	HIGH SCENARIO	WEIGHTED SCENARIO	
	25%	50%	25%	100%	Rank
1	0	0	0	0	5
3	121	816	1,975	932	1
4	109	807	1,974	924	2
5	105	805	1,971	922	3
6	(37)	641	1,781	757	4

The RIT-T analysis concluded that the proposed preferred option to address the identified need is Option 3 (Install a third 225 MVA 220/66 kV transformer at SMTS). This proposed preferred option is found to have positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver $932 million in present value net economic benefits over the 10-year evaluation period. The estimated capital cost of this option is $48.63 million ±30 per cent (real, 2025) with an optimum timing of 2028-29. This option satisfies the requirements of the RIT-T.

Submissions

AusNet and JEN invite written submissions and enquires on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "***South Morang Supply Area RIT-T***," and directed to both:

Ali Kharrazi (AusNet)

Manager, Sub-Transmission Network Planning

Email: rittconsultations@ausnetservices.com.au

and

Hung Nguyen (JEN)

Network Planning Team Leader

Email: PlanningRequest@jemena.com.au

The consultation on this PADR is open for 6 weeks consistent with the NER requirements[5]. Submissions are due on or before 22nd May 2026.

Submissions may be published on the Australian Energy Market Operator (AEMO), AusNet, and JEN 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, AusNet and JEN 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
- confirming the preferred option to meet the identified need.

Publication of the PACR will conclude the RIT-T consultation.

AusNet and JEN intend on publishing the PACR by mid-2026.

[5] NER, clause 5.16.4(r).

1. Introduction

AusNet Electricity Services Pty Ltd (AusNet) and Jemena Electricity Network (JEN) are regulated Victorian Distribution Network Service Providers (DNSPs) that supply electricity distribution services to more than 845,000 and 384,000 customers, respectively. AusNet's electricity distribution network services eastern regional Victoria and the outer northern and eastern Melbourne metropolitan area. JEN's electricity distribution network services Melbourne's northern and western greater metropolitan area.

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 the 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] and is summarised in Figure 18 of Appendix A.

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].

AusNet and JEN are undertaking this RIT-T to evaluate options to maintain reliability of supply in the South Morang 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, from the transmission connection assets at South Morang Terminal Station (SMTS). The capital cost of credible options (including the proposed preferred *network* option) to address this identified need within the South Morang supply area is above the RIT-T cost threshold and so has triggered the requirement for a RIT-T.

On 27 June 2025, AusNet and JEN published the project specification consultation report (PSCR), which represented the first stage of this RIT-T process in accordance with clause 5.16 of the NER and section 4.2 of the RIT-T Application Guidelines[8]. The PSCR identified that the *network* option to address the supply reliability need at SMTS is likely to be the installation of a third 225 MVA 220/66 kV transformer at SMTS, that would be confirmed during the RIT-T process. The need for this investment has been foreshadowed in the Transmission Connection Planning Report (TCPR)[9], published jointly by the Victorian DNSPs.

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

We have now published this project assessment draft report (PADR), representing the second stage of the South Morang Supply Area RIT-T consultation process, in accordance with clause 5.16 of the NER and section 4.3 of the RIT-T Application Guidelines.

The structure of this PADR is as follows:

- **Chapter 2** describes the identified need that AusNet and JEN are seeking to address, which is in relation to the SMTS 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** details the assumptions that AusNet and JEN have employed for this RIT-T assessment;
- **Chapter 6** presents the scope, costs, and benefits of the credible options;
- **Chapter 7** details the assessment approach that AusNet and JEN have employed for this RIT-T assessment, as well as the materiality of specific categories of market benefits;
- **Chapter 8** 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 9** presents the conclusions of the PADR, details of the proposed preferred option, and next steps.

[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.

2. Description of the identified need

This chapter discusses the role of South Morang Terminal Station (SMTS) 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 expected unserved energy (EUE) for the status-quo is also presented.

2.1. South Morang supply area

SMTS is the only terminal station that supplies the South Morang supply area. SMTS was originally established with two 225 MVA 220/66 kV transformers as a new terminal station in 2008 to reinforce the electricity network for the South Morang supply area.

The geographic coverage of the South Morang supply area serviced by SMTS spans from Seymour, Kilmore, Kalkallo, Kinglake, and Rubicon in the north to Mill Park in the south, and from Doreen and Mernda in the east to Somerton and Craigieburn in the west. The electricity distribution networks for this area are the responsibility of both AusNet (71%) and JEN (29%), based on annual net energy consumption.

Figure 1 shows the regional portion of the South Morang supply area, with 66 kV sub-transmission lines shown in red.

Figure 1: South Morang terminal station (SMTS) supply area with sub-transmission lines - regional

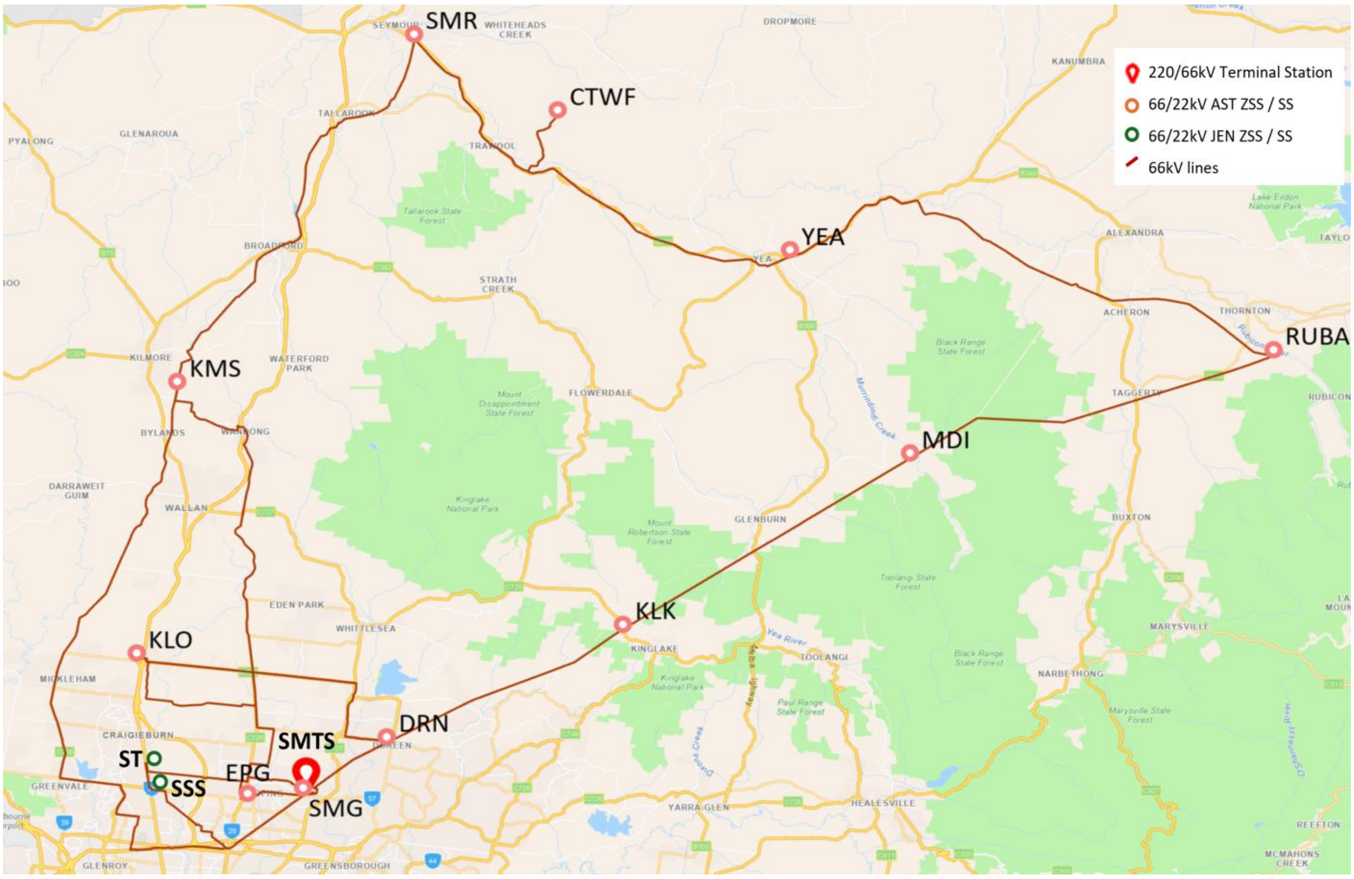
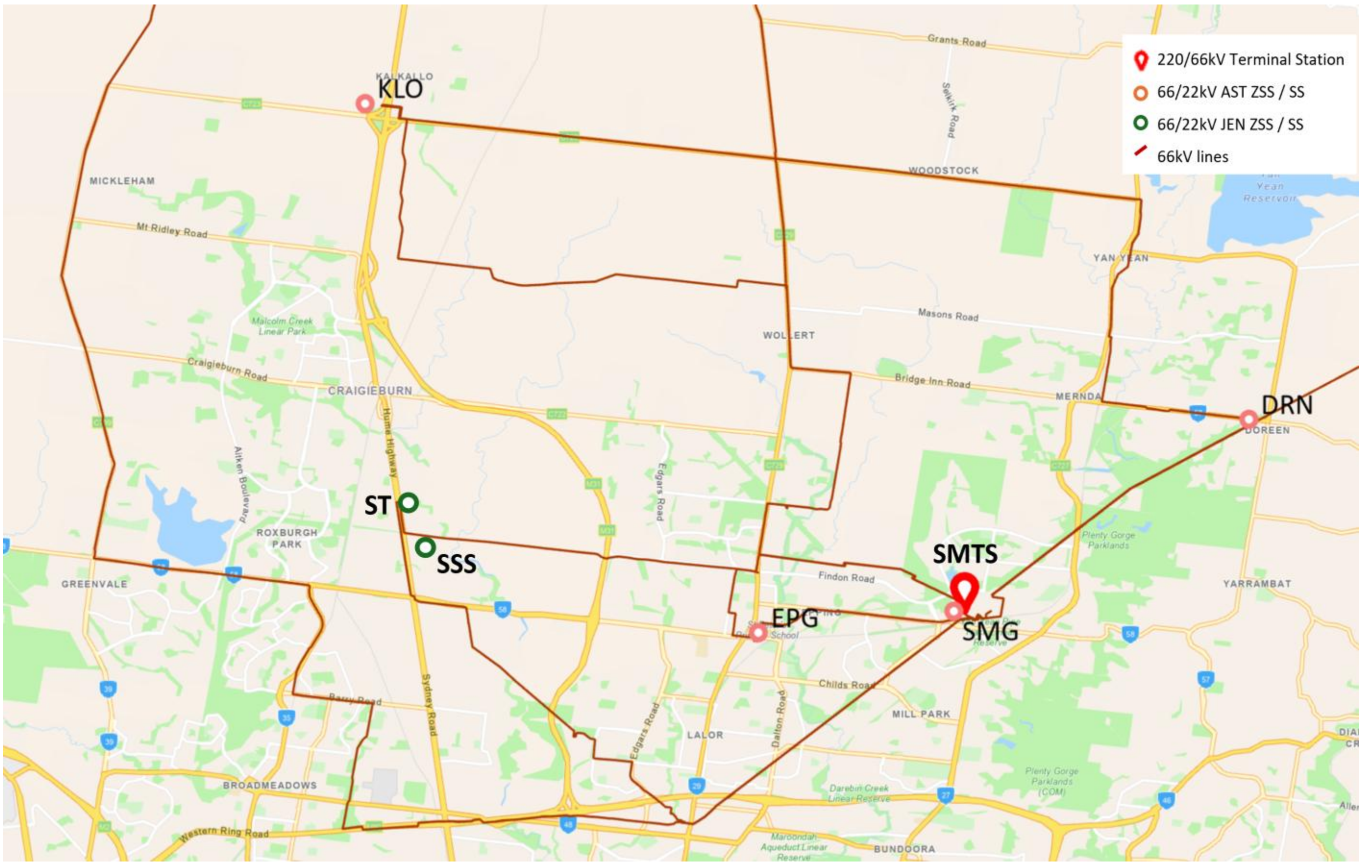


Figure 2 shows the location of SMTS within the metropolitan portion of the South Morang supply area, with 66 kV sub-transmission lines shown in red.

Figure 2: South Morang terminal station (SMTS) supply area with sub-transmission lines - metropolitan



2.1.1. Customer demand for electricity

More than 161,523 customers[10] rely on SMTS for their electricity supply. Growth in customer numbers in the supply area has been substantial. Customer number growth has averaged 7,100 additional customers per annum since 2019, an average annual increase of 5.8 per cent[11].

Residential customers consume 45.1 per cent of the total annual energy supplied from SMTS as listed in Table 2. This is closely followed by commercial customers, consuming 43.7 per cent of the total annual energy supplied.

[10] Total customer numbers in 2024-25 were 37,268 JEN customers, and 124,255 AusNet customers.
[11] Total customer numbers in 2019 were 24,751 JEN customers, and 98,427 AusNet customers.

Table 2: SMTS net energy consumption composition

CUSTOMER TYPE	SHARE OF CONSUMPTION (%)
Residential	45.1
Commercial	43.7
Industrial	9.0
Agricultural	2.2
Total	100

SMTS is a summer-peaking terminal station. Electricity demand on SMTS has been amongst the fastest growing in Victoria, and SMTS is reaching its full capacity soon. The summer peak demand at SMTS increased by 211 MVA between 2011-12 and 2024-25, equivalent to an average annual growth rate of 16 MVA or 5.2 per cent. In 2024-25 the summer maximum demand reached 434.8 MVA, which is the historical maximum for this terminal station.

The 10 per cent and 50 per cent probability of exceedance (POE) forecast summer maximum demands in 2025-26 are expected to reach 459 MVA and 431 MVA respectively. Section 5.2.2 provides an overview of the maximum demand forecasts that underpin the identified need.

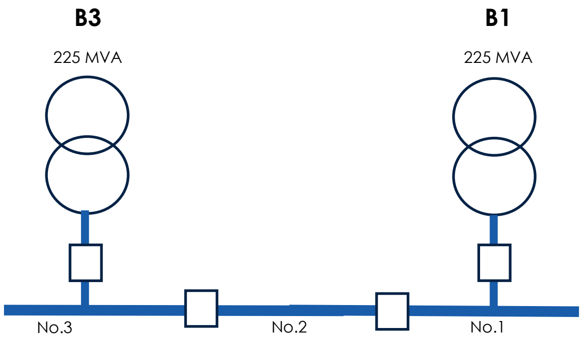
2.1.2. Electricity network servicing the supply area

SMTS currently has two parallel 220/66 kV 225 MVA transformers and three 66 kV buses. A simplified single line diagram of SMTS is provided in Figure 3.

The summer cyclic rating of SMTS with all plant in service is 538 MVA at 35°C and 519 MVA at 40°C. This rating is expected to be exceeded in 2028-29 for the POE10, and in 2030-31 for the POE50[12].

The summer cyclic rating of SMTS with one of its two transformers out of service, reduces to 269 MVA at 35°C and 259 MVA at 40°C and this rating is expected to be exceeded every year from now.

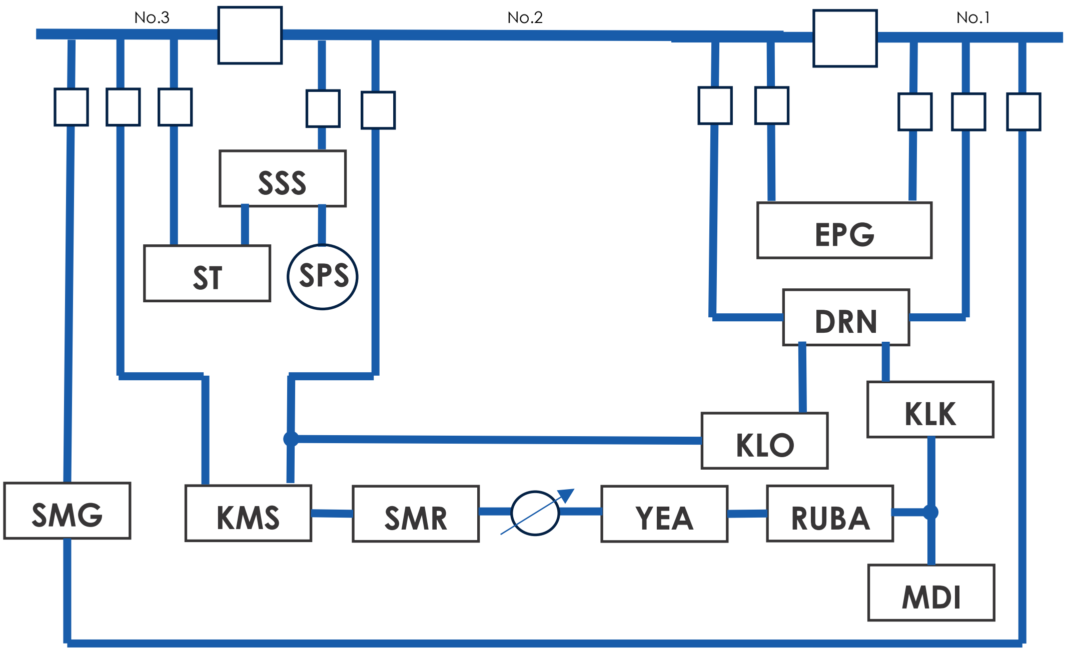
Figure 3: SMTS existing transmission connection assets single line diagram



SMTS has ten 66 kV sub-transmission line exits supplying ten AusNet zone substations, Epping (EPG), Doreen (DRN), Kalkallo (KLO), Kinglake (KLK), Murrindindi (MDI), Rubicon (RUBA), Seymour (SMR), Kilmore South (KMS), and South Morang (SMG), one JEN zone substation, Somerton (ST), and Somerton power station (SPS) via a switching station (SSS). This is shown schematically in Figure 4.

[12] To identify overload timing, the 35°C cyclic rating is compared against the POE50 forecast demand, and the 40°C cyclic rating is compared against the POE10 forecast demand.

Figure 4: SMTS existing sub-transmission network schematic diagram



As of 2025, about 204 MW of rooftop solar PV is installed on the AusNet distribution system and about 85 MW of rooftop solar PV is installed on the JEN distribution system connected to SMTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW. A total of 247.2 MW capacity of large-scale embedded generation is installed on the AusNet and JEN sub-transmission and distribution systems connected to SMTS.

Table 3: SMTS embedded generation

SITE NAME	TYPE	CAPACITY (MW)
Somerton Power Station	Gas	150
Cherry Tree Wind Farm	Wind	57.5
Wollert Power Station	Landfill gas	7.7
Rubicon Power Station	Hydroelectric	14.6
Distributed Solar PV (JEN)	Solar	85
Distributed Solar PV (AusNet)	Solar	204

2.2. Identified need

There is forecast to be insufficient capacity to supply the forecast maximum demand at SMTS with the existing transmission connection assets that are in place under system normal conditions by 2028-29 based on POE10 forecasts, or 2030-31 based on POE50 forecasts. Under single contingency conditions, there is already load at risk based on POE50 demand forecasts. The amount of load at risk will increase going forward and this is likely to lead to a significant deterioration in supply reliability for customers within the South Morang supply area and inhibit the connection of new customers.

The maximum demand growth in the SMTS supply area is primarily due to the following:

- staged development of residential estates and other residential subdivisions; commercial developments, such as shopping centres, childcare centres, schools, medical centres and retail hubs, associated with new large residential developments and large customer loads; and
- electrification of gas and transport sectors of society, associated with the energy transition.

The identified need for this RIT-T is to maintain electricity supply reliability and mitigate forecast increases in expected unserved energy (EUE) for those customers supplied from SMTS.

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

There are two drivers of EUE at SMTS - a lack of "N" capacity (system normal - with all plant in service), and a lack of "N-1" capacity (single contingency - with one transformer out of service).

Table 4 summarises the forecast "N" system normal capacity limitations at SMTS. The underlying maximum demand forecasts are shown in section 5.2.2.

Table 4: SMTS capacity limitations (EUE for "N" condition)

YEAR[13]	POE10		POE50		PROBABILITY WEIGHTED[14]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)[15]
2026	0.0	0	0.0	0	0.0	0.0
2027	0.0	0	0.0	0	0.0	0.0
2028	0.0	0	0.0	0	0.0	0.0
2029	6.0	1	0.0	0	0.3	0.0
2030	20.1	2	0.0	0	4.5	0.2
2031	49.8	8	0.0	0	25.3	1.1
2032	113.7	69	46.1	43	802.4	33.9
2033	167.4	173	73.5	117	2,998	126.8
2034	218.6	325	98.5	211	7,575	320.3
2035	251.3	405	113.5	289	11,436	483.5

[13] Half year ending 1st April for summer demands, and half year ending 1st October for winter demands.
[14] 30% weighting applied on the POE10 EUE, and 70% weighting applied on the POE50 EUE, also considering the risk reduction provided by the available distribution feeders load transfer capabilities. This weighting is consistently used by the Victorian DNSPs in its TCPR.
[15] These EUE cost estimates have been calculated by multiplying the EUE (MWh) by the load-weighted value of customer reliability for the South Morang supply area ($42,284/MWh, as set out in section 7.1.1, below).

There is forecast to be insufficient capacity to supply the growing demand at SMTS from 2028-29 under system normal ("N") operating conditions for a POE10 maximum demand. The station "N" cyclic rating is expected to be reached under a POE50 forecast from summer 2030-31.

The 'N' EUE is estimated to have a value to consumers of around $483.5 million (real, 2025) by 2034-35.

Table 5 provides a summary of the forecast "N-1" single contingency condition capacity limitations at SMTS (i.e., excluding the "N" system normal limitations presented above). The underlying maximum demand forecasts are shown in section 5.2.2.

Table 5: SMTS capacity limitations (EUE for "N-1" condition)

YEAR[13]	POE10		POE50		PROBABILITY WEIGHTED[14]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)[15]
2026	200.3	2,090	162.4	1,614	324.4	13.7
2027	229.8	2,760	193.6	2,215	512.5	21.7
2028	242.9	3,438	206.7	2,835	754.1	31.9
2029	259.0 [16]	3,938	231.9	3,313	941.5	39.8
2030	259.0	4,586	244.2	3,848	1,189	50.3
2031	259.0	5,180	269.0 [17]	4,389	1,475	62.4
2032	259.0	5,948	269.0	5,215	2,023	85.5
2033	259.0	6,300	269.0	5,652	2,397	101.3
2034	259.0	6,585	269.0	6,002	2,768	117.0
2035	259.0	6,768	269.0	6,261	3,010	127.3

The historical and forecast maximum demand under a transformer outage ("N-1") has exceeded the cyclic rating of SMTS every year since 2015-16, with levels of "N-1" load-at-risk during peak loading periods reaching the full transformer capacity of 259 MVA from 2028-29 for a POE10 forecast maximum demand. For an outage of one 220/66 kV transformer at SMTS, there will be insufficient capacity at this terminal station to supply all demand at the POE10 forecast maximum demand for about 2,090 hours in 2025-26, and 1,614 hours for the POE50 forecast maximum demand.

The probability of a major transformer outage is very low, with a network average of 1.0 per cent per transformer per annum applied for this assessment[18], contributing to an expected unavailability per transformer per annum of 0.22 per cent.

The post-contingent emergency load transfer away from SMTS to other terminal stations is insignificant.

When the energy-at-risk is weighted by the low unavailability, the EUE is estimated to be around 324.4 MWh in 2025-26. This EUE is estimated to have a value to consumers of around $13.7 million (real, 2025). By 2034-35, this increases to 3,010 MWh and $127.3 million (real, 2025).

The estimates of EUE and its financial value assumes a 70 per cent weighting of moderate temperatures (POE50) occurring in each year, and a 30 per cent weighting of higher temperature conditions (POE10), using a location-specific load-weighted value of customer reliability (VCR) of $42,284/MWh.[19]

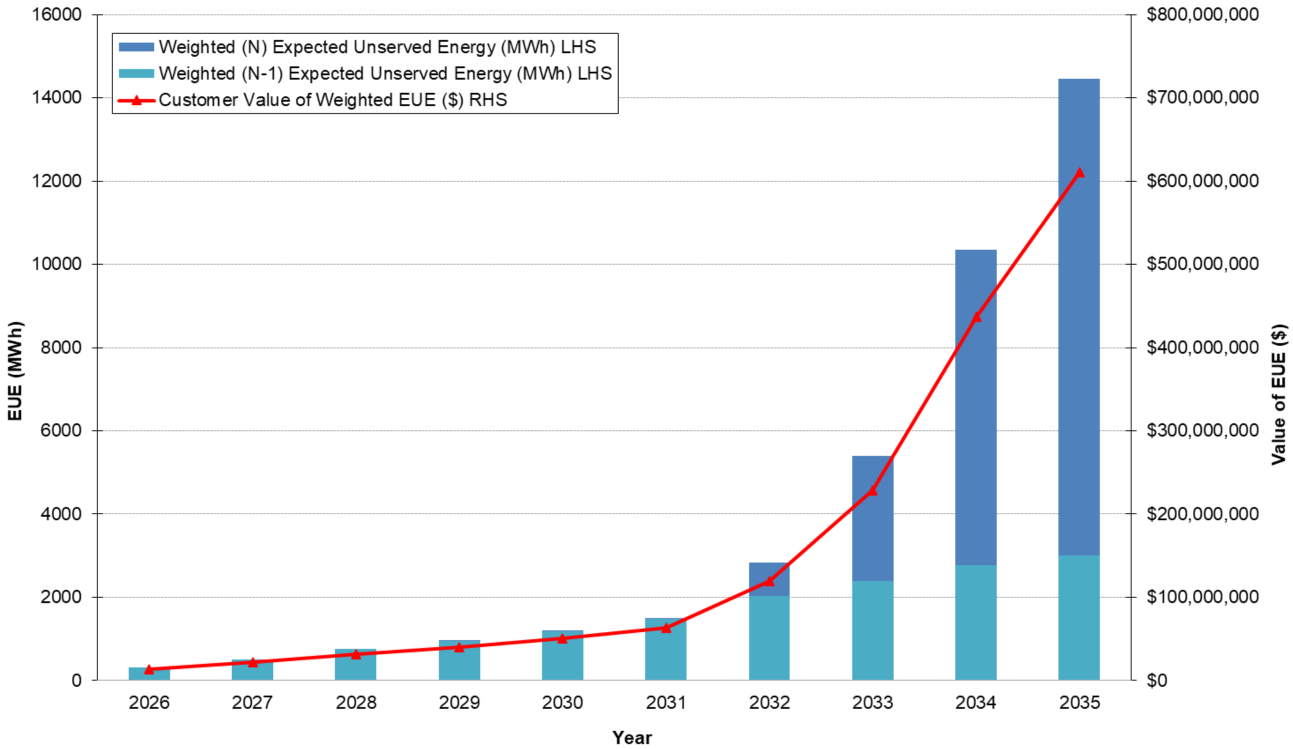
[16] The N-1 load-at-risk cannot exceed the transformer rating. The POE10 load-at-risk is capped to the 40°C transformer rating for N-1 as the load begins to exceed the N rating.
[17] The N-1 load-at-risk cannot exceed the transformer rating. The POE50 load-at-risk is capped to the 35°C transformer rating for N-1 as the load begins to exceed the N rating.
[18] Consistent with the TCPR. We use an average failure rate rather than a condition-based failure rate in this RIT-T because the need is driven by capacity limitations, not poor asset condition. The existing transformers at SMTS are in good condition and do not warrant the use of an elevated failure rate which could trigger an early asset replacement.
[19] See section 7.1.1.

The key elements of the "Do Nothing" supply reliability risk under the status-quo are shown in Table 6 and Figure 5 for both "N" and "N-1" conditions.

Table 6: SMTS total combined capacity limitations (EUE for "N" and "N-1" conditions)

YEAR[20]	PROBABILITY WEIGHTED[21]		YEAR	PROBABILITY WEIGHTED	
	EUE (MWh)	EUE Cost ($ million)[22]		EUE (MWh)	EUE Cost ($ million)
2026	324.4	13.7	**2031**	1,500	63.4
2027	512.5	21.7	**2032**	2,825	119.5
2028	754.1	31.9	**2033**	5,395	228.1
2029	941.8	39.8	**2034**	10,343	437.3
2030	1,193	50.4	**2035**	14,446	610.8

Figure 5: SMTS EUE risk costs (taking account of available load transfer capability)



It is the EUE associated with the "N-1" capacity of SMTS that is driving the bulk of the risk cost.

By undertaking one of the options proposed in this RIT-T, AusNet and JEN will be able to mitigate this projected deterioration in supply reliability for the South Morang supply area.

[20] Half year ending 1st April for summer demands, and half year ending 1st October for winter demands.
[21] 30% weighting on POE10 EUE and 70% weighting on POE50 EUE, also considering the risk reduction provided by the combined available distribution and sub-transmission load transfer capabilities. This weighting is consistently used by the Victorian DNSPs in its TCPR.
[22] These EUE cost estimates have been calculated by multiplying the EUE (MWh) by the load-weighted value of customer reliability for the South Morang supply area ($42,284/MWh, as set out in section 7.1.1, below).

3. Credible options assessed

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

The credible options assessed to address the identified need for the South Morang supply area include:

- **Option 1 - Do Nothing (base case)** continues to supply customers serviced by SMTS 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;
- **Option 3 - Install a third** 225 MVA 220/66 kV **transformer at SMTS** to increase the thermal capacity of the SMTS transmission connection assets to address the identified need. There is already provision to accommodate a third transformer at SMTS;
- **Option 4 - Install third and fourth** 225 MVA 220/66 kV **transformers at SMTS** to increase the thermal capacity of the SMTS transmission connection assets to address the identified need. There is already provision to accommodate a third and fourth transformers at SMTS;
- **Option 5 - Establish two new 10 MVA 22 kV distribution feeders to offload SMTS** to maintain the maximum demand on SMTS within its "N" rating and to maintain its present load transfer capability to address the identified need. There is opportunity to establish new 22 kV distribution feeders from AusNet's Eltham (ELM) zone substation, located just outside of the supply area, to offload SMTS; and
- **Option 6 - Establish a new 220/66 kV Donnybrook terminal station (DBTS)** to reduce the maximum demand on SMTS, transferring load to the new terminal station by re-arranging the existing sub-transmission network, thereby addressing the identified need. This is the most expensive credible option.

The different options will all result in lower EUE than in the base case, although the extent/timing of the reduction varies across the options due to the differences in the additional thermal capacity ratings they provide. JEN and AusNet 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 received to the PSCR consultation.

On 27 June 2025, AusNet and JEN published the project specification consultation report (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.

In addition, AusNet and JEN have considered whether any non-network solution could reasonably address the identified reliability need at SMTS. The identified need is driven by large, sustained peak-period capacity shortfalls under both normal and contingency conditions, requiring firm, location-specific support over extended durations. Based on this assessment, AusNet and JEN have not identified any non-network solution that could, with reasonable confidence, provide the required scale, duration, response characteristics and delivery timing to materially defer or avoid the need for network augmentation at SMTS. On this basis, no non-network option is treated as a credible option for the purpose of this PADR in addressing the identified need of the South Morang supply area.

5. Assumptions used in identifying the identified need

This chapter details the assumptions used in identifying the identified need.

First, we set out the probabilistic planning approach applied by AusNet and JEN in planning the network, in the context of our overall approach to the net present value (NPV) analysis under the RIT-T. Chapter 7 provides further details on key assumptions that AusNet and JEN have adopted for this stage of the RIT-T.

5.1. Overview of approach to the NPV analysis

Consistent with the RIT-T NER requirements[23], cost benefit analysis guidelines[24] and RIT-T application guidelines[25], AusNet and JEN 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. The proposed assessment method for this RIT-T is set out in more detail in chapter 7.

In planning the network, AusNet and JEN apply a probabilistic planning approach 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 monetised as the product of:

- expected unserved energy (EUE) driven by the identified capacity limitations, in MWh per annum; and
- the locational value of customer reliability (VCR), in $/MWh, as set by the AER.

Having identified the service level reliability risk, AusNet and JEN have taken into account the potential 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. This leads into the analysis of this PADR, where the credible option that maximises the present value of net economic benefit is identified by:

- quantifying 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 then 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.

---

[23] Regulatory investment test for transmission, Australian Energy Regulator, 21 November 2024.
[24] Cost Benefit Analysis guideline, Australian Energy Regulator, 21 November 2024.
[25] RIT-T application guideline, Australian Energy Regulator, 21 November 2024.

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.

5.2. Input assumptions

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

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

5.2.1. Network asset ratings

The capability of the transmission connection assets at SMTS is limited by the thermal cyclic rating of its two parallel 220/66 kV 225 MVA transformers. Table 7 provides a summary of the capability of SMTS for "N" and "N-1" conditions during summer and winter (maximum demand) seasons.

Table 7: SMTS thermal capacity cyclic ratings (MVA)

SEASON	EXISTING	
	"N"	"N-1"
Summer 35 Degrees Celsius	538	269
Summer 40 Degrees Celsius	519	259
Winter 15 Degrees Celsius	543	271

Section 6.3 shows how these thermal capacity ratings would be expected to increase following the implementation of the proposed preferred network option.

5.2.2. Forecast maximum demand

The forecast maximum demand at SMTS 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 periods[26]. Table 8 provides a summary of the forecast maximum demand for SMTS during summer and winter (maximum demand) seasons.

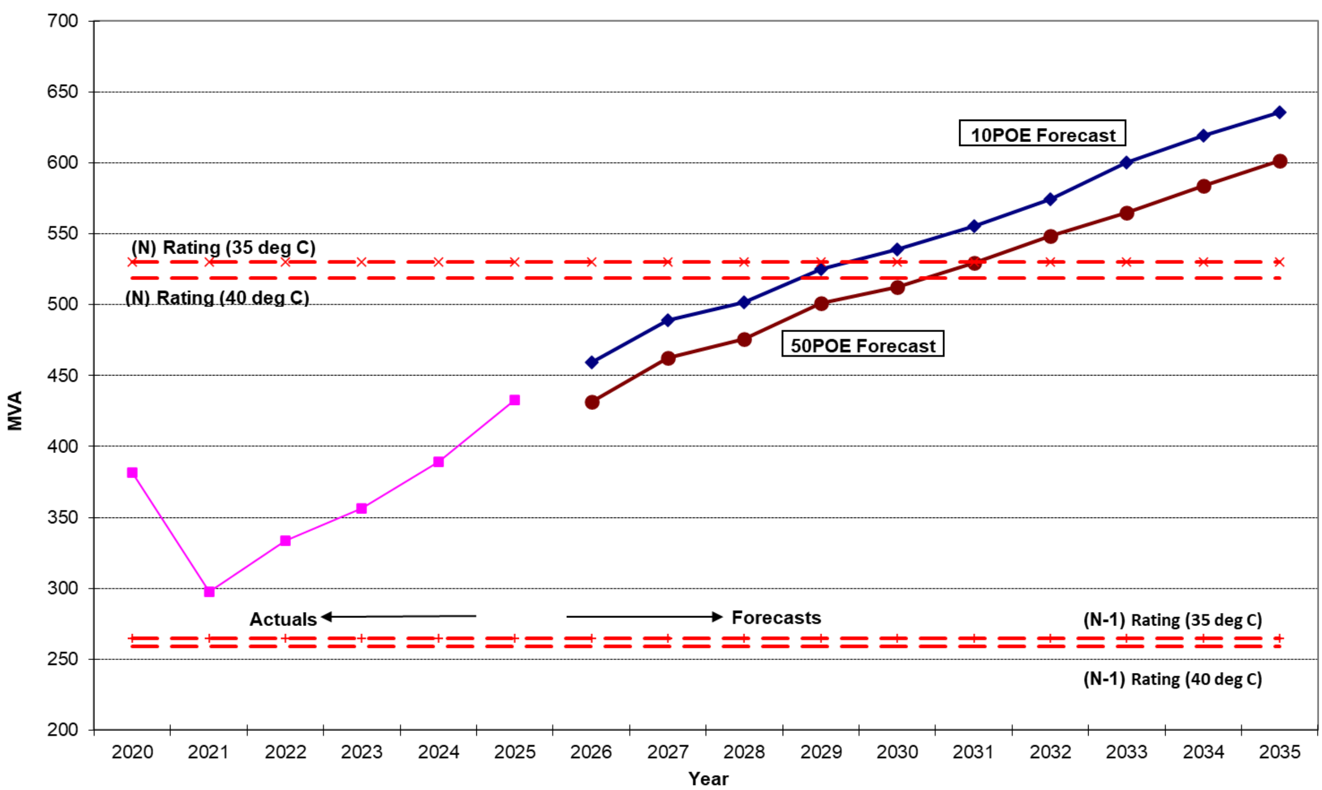
[26] Victorian electricity demand is sensitive to ambient temperature. Maximum demand forecasts are therefore based on expected demand during extreme temperature that could occur once every ten years (POE10) and during average conditions that could occur every second year (POE50).

Table 8: SMTS forecast maximum demand (MVA)

YEAR[27]	MAXIMUM DEMAND SEASON AND POE			
	Summer POE10	Winter POE10	Summer POE50	Winter POE50
2026	459	390	431	374
2027	489	422	463	409
2028	502	451	476	437
2029	525	486	501	471
2030	539	502	512	490
2031	555	530	529	515
2032	575	557	548	540
2033	600	601	565	589
2034	619	629	584	616
2035	636	662	602	641

Figure 6 shows the POE10 and the POE50 forecasts maximum demand for SMTS during summer periods relative to its capacity.

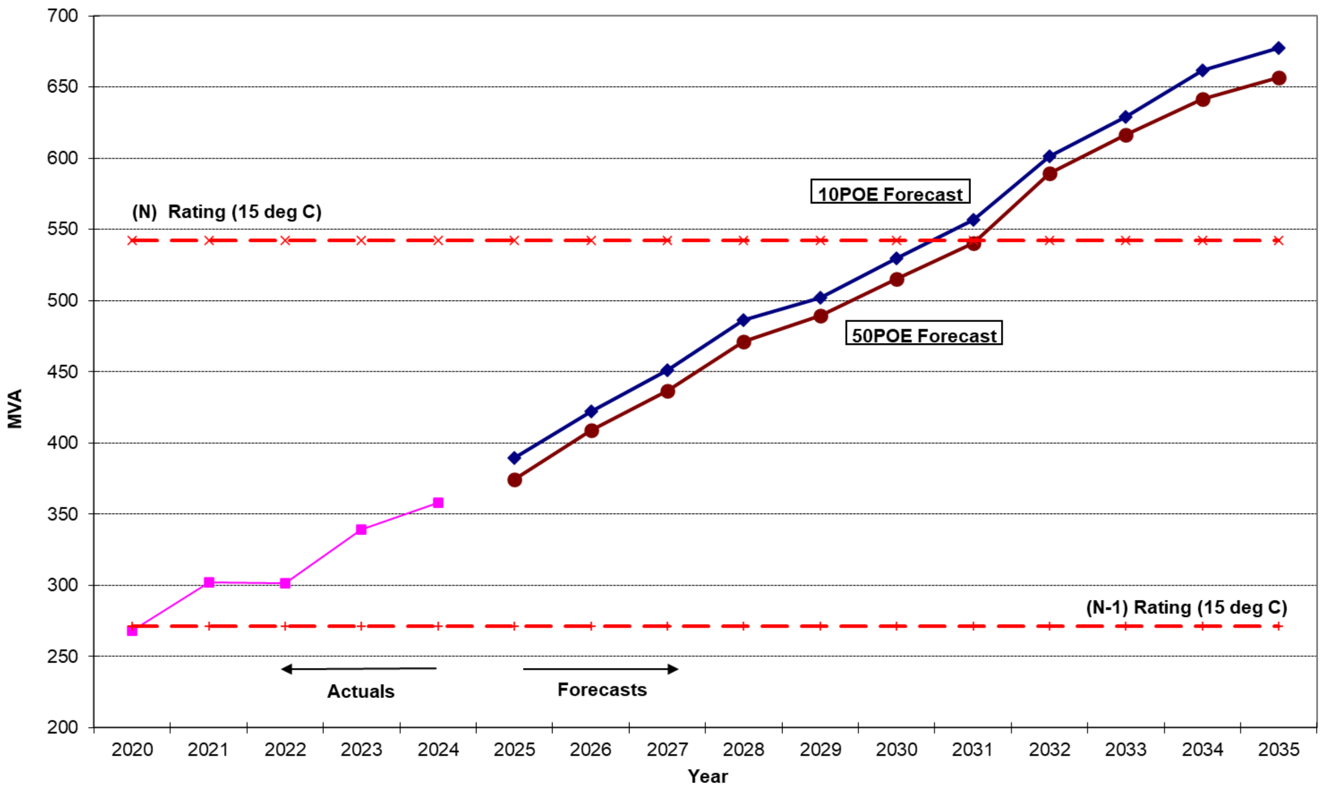
Figure 6: Summer period maximum demand forecasts for SMTS



27 Half year ending 1st April for summer demands, and half year ending 1st October for winter demands.

Figure 7 shows the POE10 and the POE50 forecast maximum demand for SMTS during winter periods relative to its capacity.

Figure 7: Winter period maximum demand forecasts for SMTS



The maximum demand growth in the SMTS supply area is primarily due to the following:

- staged development of residential estates and other residential subdivisions; commercial developments, such as shopping centres, childcare centres, schools, medical centres and retail hubs, associated with new large residential developments and large customer loads; and
- electrification of gas and transport sectors of society, associated with the energy transition.

The maximum demand forecasts used in this PADR were updated in late 2025 following publication of the 2025 TCPR. The updates reflect latest information we have available on growth within the supply area.

5.2.3. Load transfer capability

The load transfer capability is insignificant due to REFCL limitations and limitations by the peak utilisation on the adjacent distribution feeders of zone substations connected to other terminal stations.

Table 9 provides a summary of the forecast load transfer capability away from SMTS used to calculate the EUE.

Table 9: SMTS available transfer capability (MVA)

YEAR	LOAD TRANSFER CAPABILITY (MVA)	
	Pre-contingent	Post-contingent
2025	0.0	0.0
2026	0.0	0.0
2027	0.0	0.0
2028	0.0	0.0
2029	0.0	0.0
2030	0.0	0.0
2031	0.0	0.0
2032	0.0	0.0
2033	0.0	0.0
2034	0.0	0.0

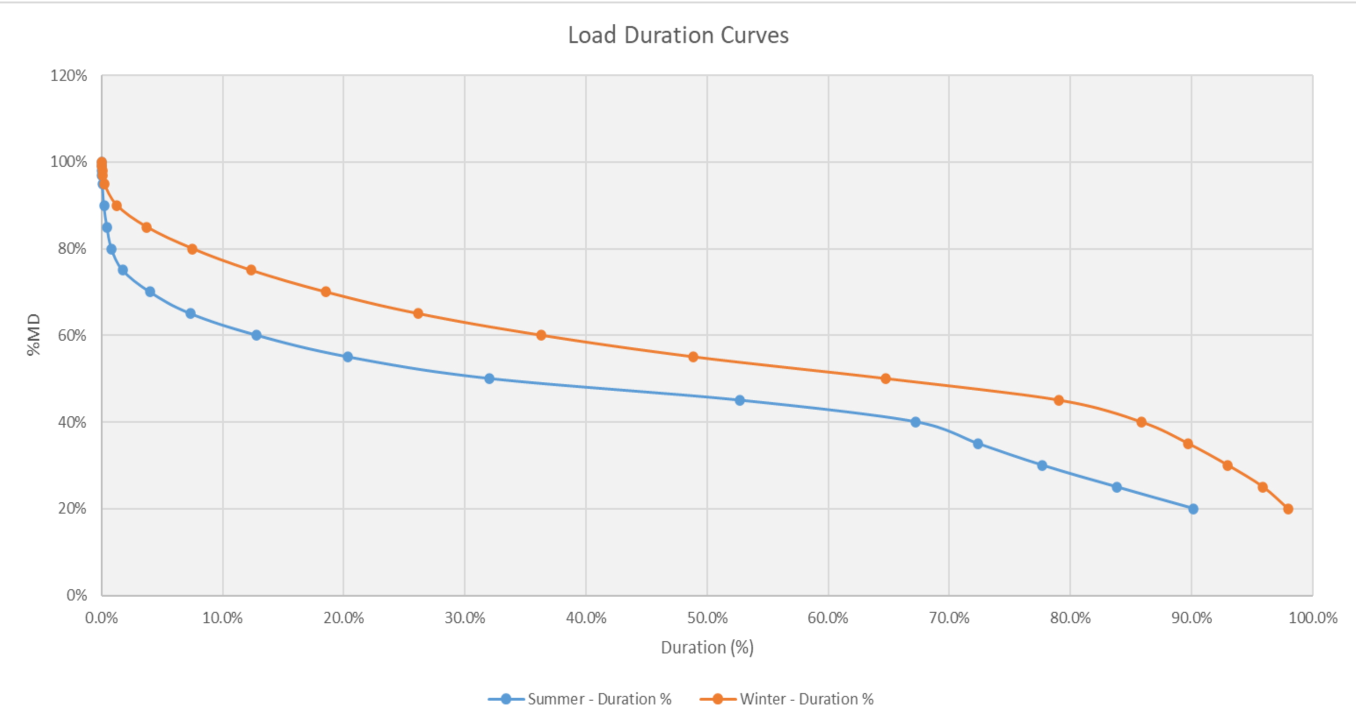
It is assumed no load transfer capability will be available over the assessment period.

5.2.4. Annual load profile

In calculating annual load profiles, consideration is made of underlying load and embedded generation contributions to the net load profile as observed at SMTS in the following charts. Underlying load is used as the basis on which to calculate EUE for this report.

The load-duration curves for SMTS are shown in Figure 8.

Figure 8: Load-duration profile for SMTS



About 204 MW of rooftop solar PV is installed on the AusNet distribution system and about 85 MW of rooftop solar PV is installed on the JEN distribution system connected to SMTS. This includes all the residential and small-commercial rooftop PV systems that are smaller than 1 MW. A total of 247.2 MW capacity of large-scale embedded generation is installed on the AusNet and JEN sub-transmission and distribution systems connected to SMTS.

5.2.5. Network asset reliability

Table 10 provides a summary of the SMTS transformer reliability information used in the EUE analysis.

Table 10: SMTS transformer reliability information[28]

POWER TRANSFORMER	VALUE	INTERPRETATION
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)	2.6 months	On average, 2.6 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 2.6/12 = 0.22% of the time, or 19 hours per year.

[28] Section 4.7 of the 2025 TCPR. We use an average failure rate rather than a condition-based failure rate in this RIT-T because the need is driven by capacity limitations, not poor asset condition. The existing transformers at SMTS are in good condition and do not warrant the use of an elevated failure rate which could trigger an early asset replacement.

6. Credible options costs and benefits

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

6.1. Option 1 – Do nothing

The "Do-nothing" option continues to supply customers serviced by SMTS without any investments to manage increasing EUE levels, utilising only the available load transfer capability to manage the risk (i.e., status quo).

This option is expected to lead to significant supply interruptions and deteriorating supply reliability under both "N" (system normal) and "N-1" (single contingency) conditions at times of peak demand, because of capacity shortfalls at SMTS.

As detailed in Table 6 for the supply reliability risk associated with the combined "N" and "N-1" conditions, the value of the EUE risk associated with the "Do nothing" option (also shown in Figure 5), is forecast to increase from $13.7 million in 2025-26 to $610.8 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 to be incurred under the "Do nothing" option, the "Do nothing" option is considered a zero-cost and zero-benefit option.

6.2. Option 2 – Non-network or SAPS solutions

Non-network or SAPS solutions contracted to provide network support services from within the distribution or sub-transmission networks serviced by SMTS, are targeted at reducing the net maximum demand on SMTS (i.e., reducing 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 embedded storage and/or generation resources.

On 27 June 2025, AusNet and JEN published the project specification consultation report (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.

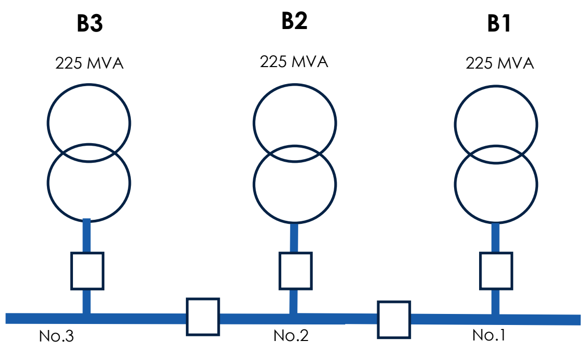
During this period of consultation on the PSCR, no non-network proposals or submissions were received from interested stakeholders.

In addition, AusNet and JEN have considered whether any non-network solution could reasonably address the identified reliability need at SMTS. The identified need is driven by large, sustained peak-period capacity shortfalls under both normal and contingency conditions, requiring firm, location-specific support over extended durations. Based on this assessment, AusNet and JEN have not identified any non-network solution that could, with reasonable confidence, provide the required scale, duration, response characteristics and delivery timing to materially defer or avoid the need for network augmentation at SMTS. On this basis, no non-network option is treated as a credible option for this PADR.

6.3. Option 3 - Install a 3rd 220/66 kV transformer at SMTS

This option involves installing a third 225 MVA 220/66 kV transformer at SMTS to increase the thermal capacity ratings of the transmission connection assets at this terminal station. There is already provision in the original design of the terminal station to accommodate a third transformer. A simplified single line diagram of the augmented transmission connection assets at SMTS is shown in Figure 9.

Figure 9: SMTS proposed transmission connection assets single line diagram (Option 3)



The scope of work required for this option includes:

- Supply and install one high impedance 225 MVA 220/66 kV transformer (to be installed in between existing B1 and B3 transformers, including fire walls).
- Add two, three-phase, series 220 kV reactors to the existing B1 and B3 transformers.
- Add three new 220 kV circuit breakers and associated equipment in Bay S of the 220 kV switchyard.
- Add automatic control scheme to switch the new transformer to the other 220 kV Bus if the normal bus is affected by a protection operation (220 kV auto-close scheme).
- Add 66 kV connection to the No.2 66 kV busbar via new 66 kV circuit breaker and associated equipment.
- Relocate 150 MVA 220/66 kV metro spare transformer to new bunded area adjacent to F Trans spare unit.
- Install and modify protection, monitoring and control equipment.

This option meets the identified need by alleviating the load at risk and removing all the EUE under N condition and materially reduce the EUE under N-1 condition at SMTS over the medium term, after installation of the third transformer at SMTS.

The estimated capital cost of this network option is $48.63 million (real, 2025) which has present value of $44.3 million and an annualised cost of $4.0 million (includes $0.5 million of operating and maintenance costs).

The expected SMTS thermal capacity ratings following the implementation of Option 3 are shown in Table 11, below.

Table 11: SMTS thermal capacity rating if Option 3 is implemented (MVA)

SEASON	B123	
	"N"	"N-1"
Summer 35 Degrees Celsius	795	530
Summer 40 Degrees Celsius	778	519
Winter 15 Degrees Celsius	813	543

This option is not likely to have a material inter-network impact.

Social licencing risks are considered minor for this option as it only involves work within an existing established terminal station (SMTS). Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

The year that the annualised costs cross the value of the avoided EUE (realised by the network augmentation), provides an optimal timing for the third transformer of summer 2026-27 as shown in Figure 10. With a construction timetable of two to three years, the timing is 2028-29.

Figure 10: Optimal timing based on avoided risks and annualised costs (Option 3)

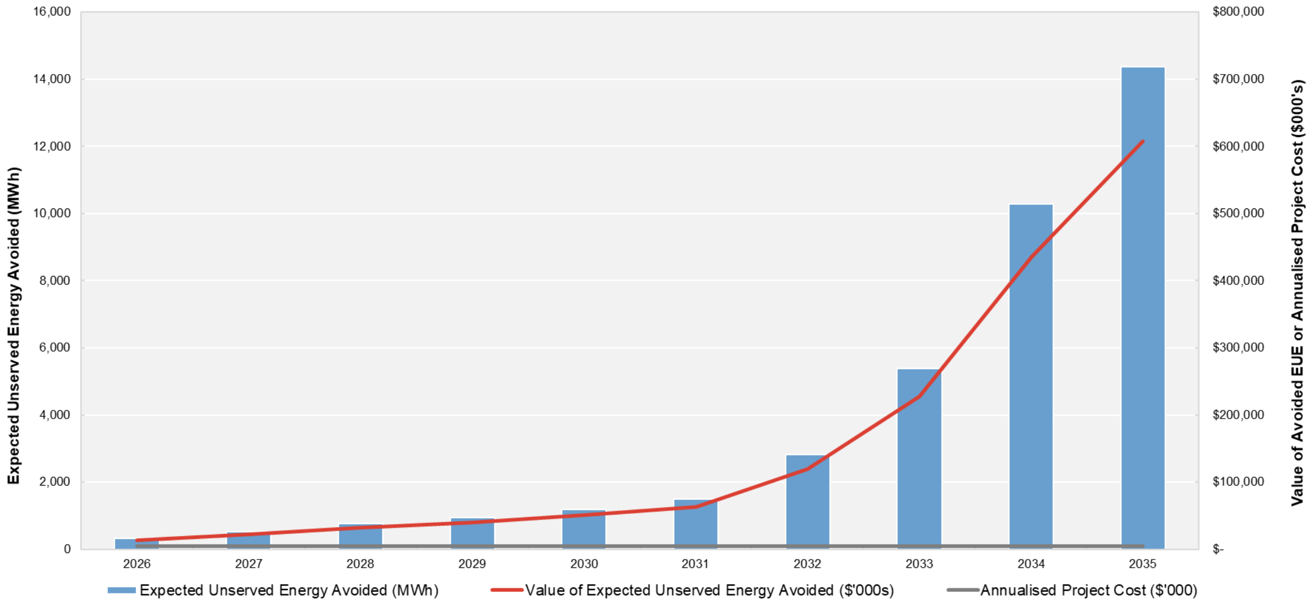


Table 12 lists the forecast "N" system normal limitations at SMTS with Option 3 in service, based on its optimum timing.

Table 12: SMTS capacity limitations with Option 3 in service (EUE for "N" condition)

YEAR[29]	POE10		POE50		PROBABILITY WEIGHTED[30]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	0.0	0	0.0	0	0.0	0.0
2027	0.0	0	0.0	0	0.0	0.0
2028	0.0	0	0.0	0	0.0	0.0
2029	0.0	0	0.0	0	0.0	0.0
2030	0.0	0	0.0	0	0.0	0.0
2031	0.0	0	0.0	0	0.0	0.0
2032	0.0	0	0.0	0	0.0	0.0
2033	0.0	0	0.0	0	0.0	0.0
2034	0.0	0	0.0	0	0.0	0.0
2035	0.0	0	0.0	0	0.0	0.0

Table 13 lists the forecast "N-1" contingency limitations at SMTS (i.e., excluding the "N" system normal limitations presented above) with Option 3 in service, based on its optimum timing.

Table 13: SMTS capacity limitations with Option 3 in service (EUE for "N-1" condition)

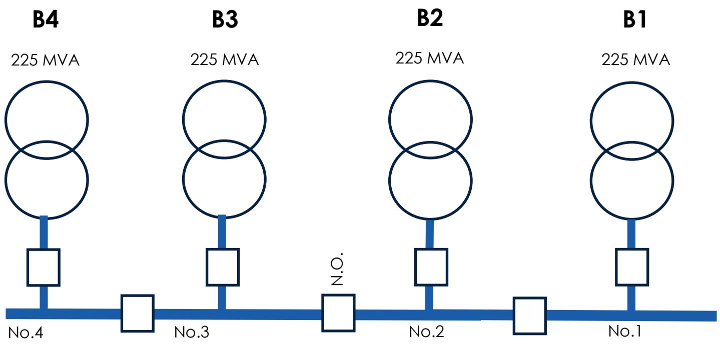
YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	200.3	2,090	162.4	1,614	324.4	13.7
2027	229.8	2,760	193.6	2,215	512.5	21.7
2028	242.9	3,438	206.7	2,835	754.1	31.9
2029	6.0	1	0.0	0	0.0	0.0
2030	20.1	2	0.0	0	0.0	0.0
2031	36.3	8	0.0	0	0.2	0.0
2032	58.2	69	46.1	43	5.3	0.2
2033	86.3	173	73.5	117	19.9	0.8
2034	118.5	325	98.5	211	50.2	2.1
2035	134.4	405	113.5	289	75.8	3.2

[29] Half year ending 1st April for summer demands, and half year ending 1st October for winter demands.
[30] 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.

6.4. Option 4 - Install 3rd & 4th 220/66 kV transformers at SMTS

This option involves installing third and fourth 225 MVA 220/66 kV transformers at SMTS to increase the thermal capacity ratings of the transmission connection assets at SMTS. There is already provision in the original design of the terminal station to accommodate third and fourth transformers. A simplified single line diagram of the augmented transmission connection assets at SMTS is shown in Figure 11.

Figure 11: SMTS proposed transmission connection assets single line diagram (Option 4)



The scope of work required for this option includes:

- Supply and install two high impedance 225 MVA 220/66 kV transformers.
- Add two, three-phase, series 220 kV reactors to the existing B1 and B3 transformers.
- Add three new 220 kV circuit breakers and associated equipment in Bay S of the 220 kV switchyard.
- Add automatic control scheme.
- Add 66 kV connection to the No.2 66 kV busbar via new 66 kV circuit breaker and associated equipment.
- Establish No.4 66 kV busbar and establish 4th transformer connection via new 66 kV circuit breaker and associated equipment.
- Relocate 150 MVA 220/66 kV metro spare transformer to new bunded area adjacent to F Trans spare unit.
- Install and modify protection, monitoring and control equipment.
- 66 kV feeder bay reallocations.

This option meets the identified need by alleviating the load at risk and removing all the EUE at SMTS, after installation of the third and fourth transformers at SMTS, over the next ten years.

The estimated capital cost of this network option is $64.4 million (real, 2025) which has present value of $57.1 million and an annualised cost of $5.5 million (includes $0.6 million of operating and maintenance costs).

The expected SMTS thermal capacity ratings following the implementation of Option 4 are shown in Table 14, below.

Table 14: SMTS thermal capacity rating if Option 4 is implemented (MVA)

SEASON	B12		B34	
	"N"	"N-1"	"N"	"N-1"
Summer 35 Degrees Celsius	538	269	538	269
Summer 40 Degrees Celsius	519	259	519	259
Winter 15 Degrees Celsius	543	271	543	271

This option is not likely to have a material inter-network impact.

Social licencing risks are considered minor for this option as it only involves work within an existing established terminal station (SMTS). Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

The year that the annualised costs crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing for the third and fourth transformers of summer 2026-27 as shown in Figure 12. With a construction timetable of three to four years, the timing is 2028-29 for the first transformer and 2029-30 for the second.

Figure 12: Optimal timing based on avoided risks and annualised costs (Option 4)

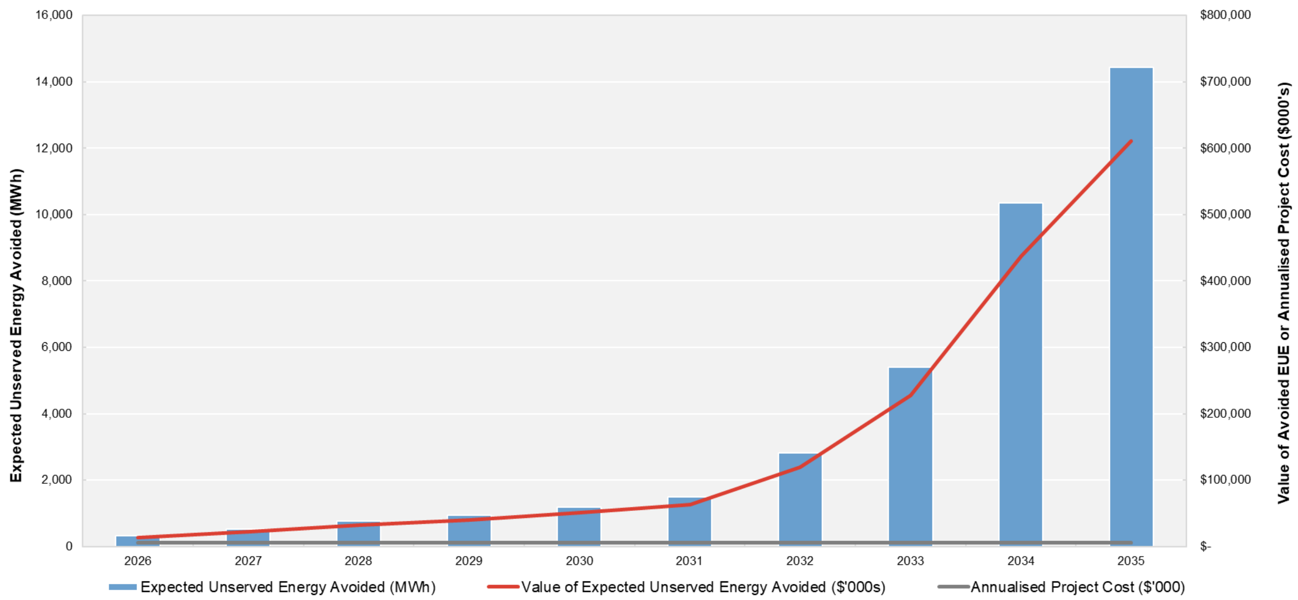


Table 15 lists the forecast "N" system normal limitations at SMTS with Option 4 in service, based on its optimum timing.

Table 15: SMTS capacity limitations with Option 4 in service (EUE for "N" condition)

YEAR[31]	POE10		POE50		PROBABILITY WEIGHTED[32]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	0.0	0	0.0	0	0.0	0.0
2027	0.0	0	0.0	0	0.0	0.0
2028	0.0	0	0.0	0	0.0	0.0
2029	0.0	0	0.0	0	0.0	0.0
2030	0.0	0	0.0	0	0.0	0.0
2031	0.0	0	0.0	0	0.0	0.0
2032	0.0	0	0.0	0	0.0	0.0
2033	0.0	0	0.0	0	0.0	0.0
2034	0.0	0	0.0	0	0.0	0.0
2035	0.0	0	0.0	0	0.0	0.0

Table 16 lists the forecast "N-1" contingency limitations at SMTS (i.e., excluding the "N" system normal limitations presented above) with Option 4 in service, based on its optimum timing.

Table 16: SMTS capacity limitations with Option 4 in service (EUE for "N-1" condition)

YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	200.3	2,090	162.4	1,614	324.4	13.7
2027	229.8	2,760	193.6	2,215	512.5	21.7
2028	242.9	3,438	206.7	2,835	754.1	31.9
2029	6.0	1	0.0	0	0.0	0.0
2030	0.0	0	0.0	0	0.0	0.0
2031	0.0	0	0.0	0	0.0	0.0
2032	0.0	0	0.0	0	0.0	0.0
2033	0.0	0	0.0	0	0.0	0.0
2034	0.0	0	0.0	0	0.0	0.0
2035	0.0	0	0.0	0	0.0	0.0

[31] Half year ending 1st April for summer demands, and half year ending 1st October for winter demands.
[32] 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.

6.5. Option 5 - Establish two new 10 MVA feeders to offload SMTS, followed by Option 3

This option involves establishing two new 22 kV 10 MVA[33] distribution feeders to increase the transfer capacity away from SMTS and reduce the post-contingent EUE exposure at SMTS.

Table 17 provides a summary of the new feeder opportunities and the increase in transfer capability provided to SMTS by each of those feeders, considering the available spare capacity on their upstream assets and the maximum demand on the feeders being transferred.

Table 17: New 22 kV distribution feeder opportunities to increase transfer capacity of SMTS

TO NEW FEEDER ZONE SUBSTATION	FROM SMTS ZONE SUBSTATION	TRANSFER CAPABILITY PROVIDED (MVA)
1st new feeder ex Eltham (ELM)	South Morang (SMG) part of SMG23, SMG31	10 MVA
2nd new feeder ex Eltham (ELM)	Doreen (DRN) part of DRN13, DRN23	10 MVA

The estimated capital cost of the two new feeders is $20.0 million (real, 2025) which has present value of $19.0 million and an annualised cost of $1.6 million. The optimal timing for commissioning the new feeders being summer 2026-27.

The total increase in transfer capacity provided by the two new feeders is 20 MVA, well below the load at risk. Hence investment in these feeders is unable to address the identified need on its own. With a maximum demand growth rate at SMTS being around the level of the additional transfer capacity provided, the two feeders are able to support the EUE risk in the lead up to implementing Option 3. Therefore, for the purposes of this RIT-T, this option is assumed to be undertaken with the Option 3.

The estimated capital cost of Option 5 is $68.63 million (real, 2025). This combined option meets the identified need by alleviating the supply capacity risk and removing all the EUE under N condition and materially reduce the EUE under N-1 condition at SMTS over the medium term. The total present value capital cost of this combined network option is $63.2 million, and has an annualised cost of $5.7 million (includes $0.7 million of operating and maintenance costs).

This option is not likely to have a material inter-network impact.

Social licencing risks are considered moderate for this option as it only involves work within an existing established substation, standard overhead pole lines and underground cables within existing road reserves and easements. Localised community consultation and associated building and planning permitting will be undertaken as part of this option.

The year that the annualised costs cross the value of the avoided EUE (realised by the network augmentations), provides an optimal timing for the feeders then the third transformer of summer 2028-29 as shown in Figure 13, with a total construction timetable of two to three years.

---

[33] The rating of each feeder is likely to be determined by voltage drop rather than thermal limitations, due to the relatively long distance involved to reach the load centres, and with the bulk of the load being right at the end of each new feeder.

Figure 13: Optimal timing based on avoided risks and annualised costs (Option 5)

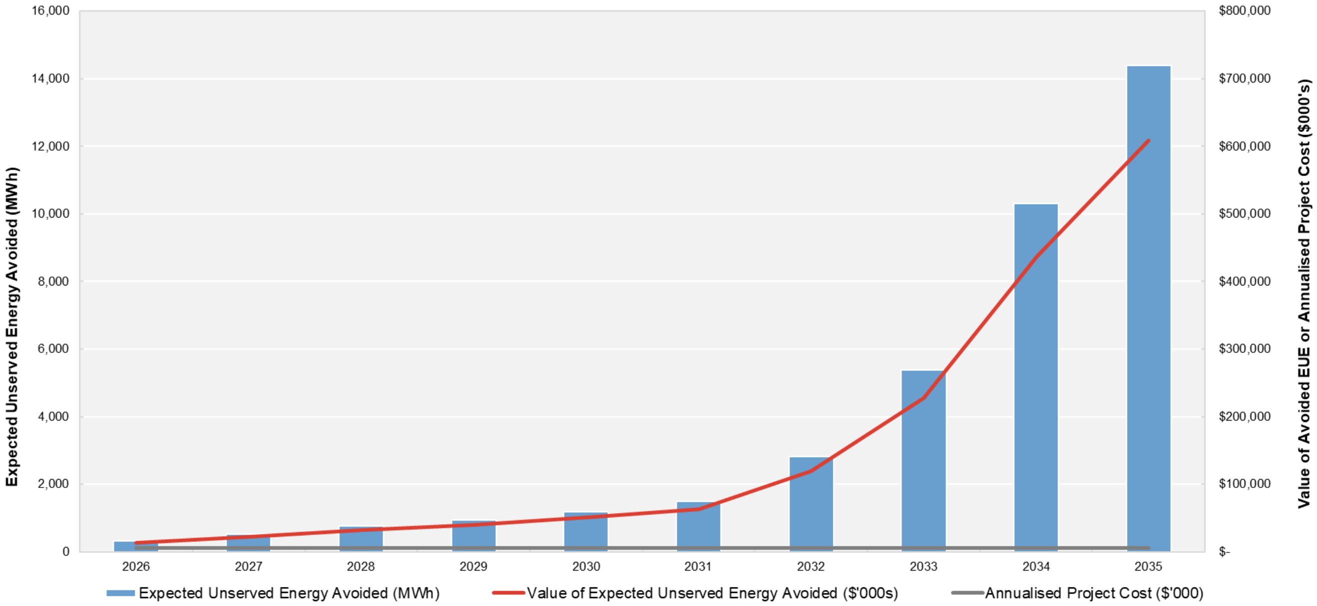


Table 18 lists the forecast "N" system normal limitations at SMTS with Option 5 in service, based on its optimum timing.

Table 18: SMTS capacity limitations with Option 5 in service (EUE for "N" condition)

YEAR[34]	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	0.0	0	0.0	0	0.0	0.0
2027	0.0	0	0.0	0	0.0	0.0
2028	0.0	0	0.0	0	0.0	0.0
2029	0.0	0	0.0	0	0.0	0.0
2030	0.0	0	0.0	0	0.0	0.0
2031	0.0	0	0.0	0	0.0	0.0
2032	0.0	0	0.0	0	0.0	0.0
2033	0.0	0	0.0	0	0.0	0.0
2034	0.0	0	0.0	0	0.0	0.0
2035	0.0	0	0.0	0	0.0	0.0

[34] Half year ending 1st April for summer demands, and half year ending 1st October for winter demands.

Table 19 lists the forecast "N-1" contingency limitations at SMTS (i.e., excluding the "N" system normal limitations presented above) with Option 5 in service, based on its optimum timing.

Table 19: SMTS capacity limitations with Option 5 in service (EUE for "N-1" condition)

YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	200.3	2,090	162.4	1,614	324.4	13.7
2027	229.8	2,760	193.6	2,215	512.5	21.7
2028	222.9	3,438	186.7	2,835	584.2	24.7
2029	0.0	1	0.0	0	0.0	0.0
2030	0.1	2	0.0	0	0.0	0.0
2031	16.3	8	0.0	0	0.0	0.0
2032	38.2	69	26.1	43	1.2	0.0
2033	66.3	173	53.5	117	8.0	0.3
2034	98.5	325	78.5	211	26.4	1.1
2035	114.4	405	93.5	289	44.0	1.9

6.6. Option 6 - Establish a new 220/66 kV terminal station DBTS

This option involves establishing a new two 225 MVA 220/66 kV transformers and two 500/220 kV 1,000 MVA transformers terminal station in the Donnybrook area (site owned by AusNet) to reduce the maximum demand on SMTS, transferring load to the new terminal station by re-arranging the existing sub-transmission network, thereby addressing the identified need. A possible solution would be to transfer 235 MVA of load as shown in Figure 14.

Figure 14: Possible sub-transmission network schematic diagram (Option 6)

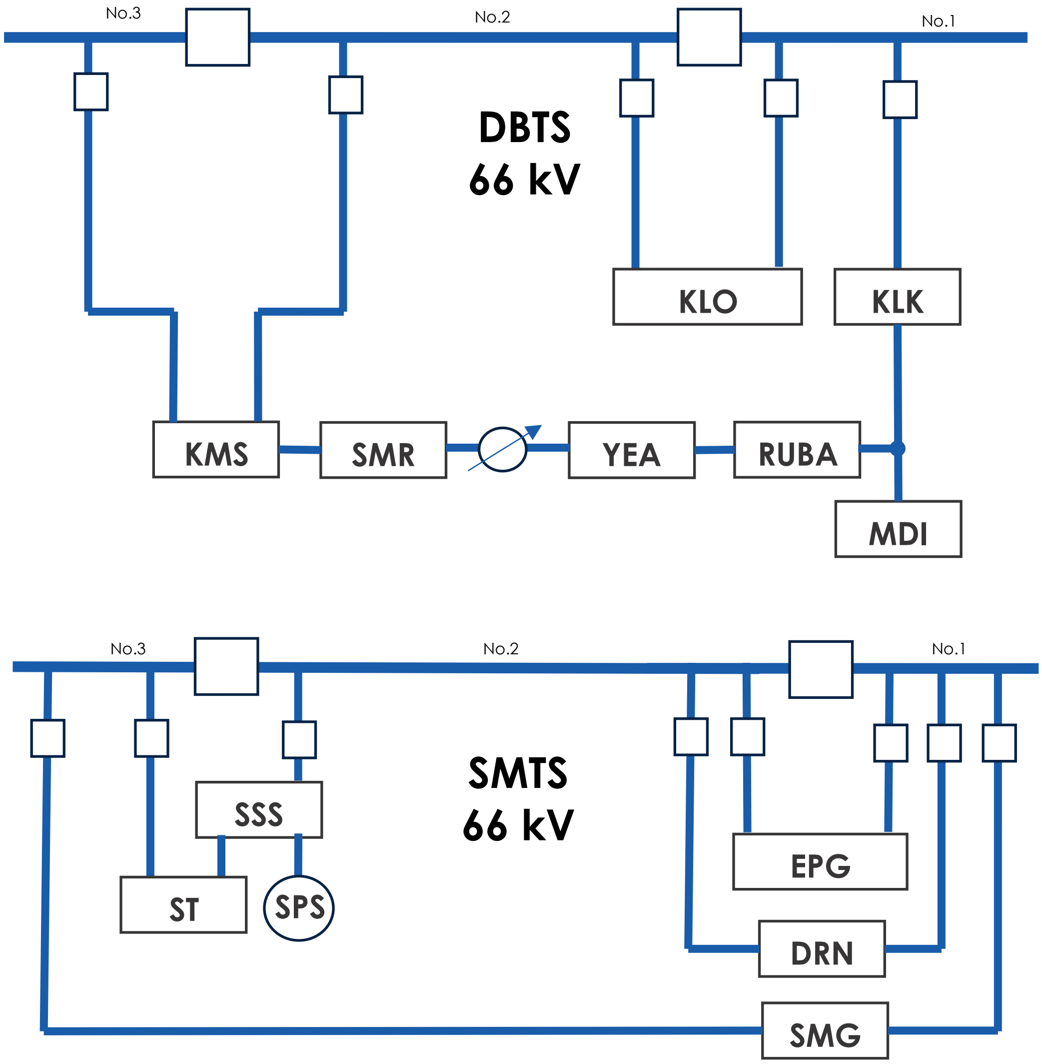


Figure 15: Land reserved for future Donnybrook terminal station geospatial diagram (Option 6)

This option is the most expensive option with a total estimated capital cost of $240 million (real, 2025) which, has a present value capital cost of $192.5 million, and has an annualised cost of $19.8 million (includes $1.2 million of operating and maintenance costs).

This option meets the identified need by alleviating the supply capacity risk and removing all the expected unserved energy over the next 10 years. Nevertheless, there is significant EUE at risk in the lead up to this augmentation, given its long lead time.

This option is not likely to have a material inter-network impact.

The option involves work to establish a new terminal station, and standard overhead pole lines and underground cables within existing road reserves and new easements, to connect into the existing distribution network. Only existing 500 kV transmission line cut-ins through the designated site are required, with no new transmission lines or extensions required. Community consultation, social licencing and associated building, environmental, cultural heritage and planning permitting will be undertaken as part of this option in the years leading up to the construction works.

The year that the annualised costs cross the value of the avoided EUE (realised by the network augmentation), provides an optimal timing for the new terminal station of summer 2027-28 as shown in Figure 16. With a planning and construction timetable of four to five years, the timing is 2029-30.

Figure 16: Optimal timing based on avoided risks and annualised costs (Option 6)

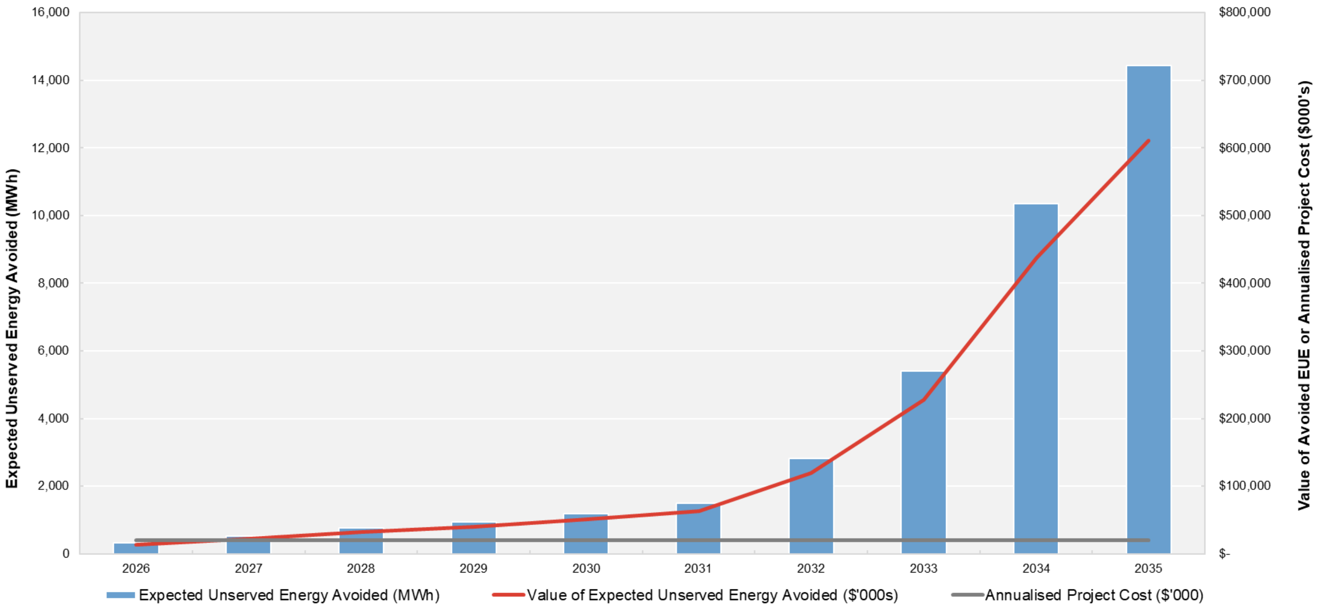


Table 18 lists the forecast "N" system normal limitations at SMTS with Option 6 in service, based on its optimum timing.

Table 20: SMTS capacity limitations with Option 6 in service (EUE for "N" condition)

YEAR[35]	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	0.0	0	0.0	0	0.0	0.0
2027	0.0	0	0.0	0	0.0	0.0
2028	0.0	0	0.0	0	0.0	0.0
2029	6.0	1	0.0	0	0.3	0.0
2030	0.0	0	0.0	0	0.0	0.0
2031	0.0	0	0.0	0	0.0	0.0
2032	0.0	0	0.0	0	0.0	0.0
2033	0.0	0	0.0	0	0.0	0.0
2034	0.0	0	0.0	0	0.0	0.0
2035	0.0	0	0.0	0	0.0	0.0

Table 19 lists the forecast "N-1" contingency limitations at SMTS (i.e., excluding the "N" system normal limitations presented above) with Option 6 in service, based on its optimum timing.

Table 21: SMTS capacity limitations with Option 6 in service (EUE for "N-1" condition)

YEAR	POE10		POE50		PROBABILITY WEIGHTED	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2026	200.3	2,090	162.4	1,614	324.4	13.7
2027	229.8	2,760	193.6	2,215	512.5	21.7
2028	242.9	3,438	206.7	2,835	754.1	31.9
2029	259.0	3,938	231.9	3,313	941.5	39.8
2030	0.0	0	0.0	0	0.0	0.0
2031	0.0	0	0.0	0	0.0	0.0
2032	0.0	0	0.0	0	0.0	0.0
2033	0.0	0	0.0	0	0.0	0.0
2034	0.0	0	0.0	0	0.0	0.0
2035	0.0	0	0.0	0	0.0	0.0

[35] Half year ending 1st April for summer demands, and half year ending 1st October for winter demands.

7. Assessment methodology

This chapter discusses the assessment methodology for the net present value (NPV) assessment of options under this RIT-T, including:

- key parameters used for this RIT-T for the cost-benefit assessment include:
    - value of customer reliability;
    - discount rate; and
    - assessment period;
- the approach to estimating option cost; and
- the materiality of each category of market benefits under the RIT-T.

7.1. Assessment parameters

7.1.1. Value of customer reliability

The cost of EUE is calculated using a value of customer reliability (VCR), which is an estimate of the value electricity consumers put on having a reliable electricity supply. AusNet and JEN have applied locational VCR values based on the Australian Energy Regulator's (AER) updated Values of Customer Reliability Review published in December 2025[36].

Applying the AER's sector VCRs to terminal station level historical energy composition data from 2024-25, a SMTS VCR of $42,284/MWh was derived, as presented in Table 22.

Table 22: SMTS value of customer reliability

SECTOR	AER VCR ($/MWH)[37]	SMTS ENERGY CONSUMPTION BY SECTOR	SMTS WEIGHTED VCR ($/MWH)
Residential	51,106	45.1%	23,058
Commercial	35,700	43.7%	15,592
Industrial	34,766	9.0%	3,116
Agricultural	23,098	2.2%	518
Composite		**100%**	**42,284**

[36] Values of Customer Reliability, Australian Energy Regulator (AER), Updated in December 2025.
[37] AER 2025 updated VCRs. Climate zone 6 and weighted average of regional and suburban residential applies at SMTS.

7.1.2. Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits. A real, 7.0 per cent, commercial discount rate is used at SMTS, aligned with AEMO's 2025 inputs, assumptions, and scenarios report[38] (IASR). For the sensitivities we use 10.0 per cent for the high bound (as per the IASR), and 3.9 per cent for the low bound representing a regulatory discount rate.

7.1.3. Assessment period

It is necessary to apply a cost-benefit analysis assessment period commensurate with the options being evaluated to address the identified need. The RIT-T analysis has been undertaken over a 10-year period as the central assumption in this PADR, with a terminal value included in the final year representing the net value of the asset over its remaining asset life.

We consider that the length of this assessment period considers the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. The assessment period accounts for expected demand growth in the South Morang supply area intended to be addressed by the credible options in this RIT-T, and the uncertainty of that demand growth.

7.2. Approach to estimating option costs

The costs for each option have been calculated by AusNet Transmission Group'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 are comprehensive including escalations, overheads, financing charges and 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 comprise 5.8%.

We note that social license costs have not been included as they are not expected to be material for this RIT-T.

Ongoing operating and maintenance costs are included in the assessment annually from the year after the capital investment at a level of 1.0 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.

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

---

38 2025 Inputs, Assumptions and Scenarios Report, Table 31, AEMO August 2025.

7.3. Materiality of market benefits

The RIT-T instrument requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the RIT-T proponent can demonstrate that:[39]

- a particular class (or classes) of market benefit is unlikely to be material in relation to the RIT-T assessment for a specific option, or
- the estimated cost of undertaking the analysis to quantify that benefit would likely be disproportionate to the scale, size and potential benefits of each credible option being considered in the report.

We consider that changes in involuntary load shedding (i.e., avoided EUE) is the only class of market benefit that will be material to the network options considered in this RIT-T assessment.

AusNet and JEN estimate that the following classes of market benefits are unlikely to be material for any of the options considered in this RIT-T:

- **Changes in fuel consumption arising through different patterns of generation dispatch**, as 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.
- **Changes in costs for parties, other than the RIT-T proponent,** as there is no other known investment, either generation or transmission, that will be affected by any option considered.
- **Changes in Australia's greenhouse gas emissions**, as changes in greenhouse gas emissions from changes in generation dispatch, renewable energy generation curtailment, or levels of SF_6 emissions from high-voltage switchgear, are considered to be negligible and unlikely to be a material class of market benefits for any of the credible options.
- **Change in network losses**, as changes in network losses are considered to be 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, nor change the ranking of options considered.
- **Additional option value**, as 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 (to the extent that timing or scope of options components, including any non-network components, varies across reasonable scenarios).
- **Changes in ancillary services costs**, as the options are not expected to impact on the demand for and supply of ancillary services.
- **Differences in the timing of expenditure**, as the timing of other unrelated expenditure is not expected to be impacted by the options considered in this assessment.
- **Avoided unrelated network expenditure**, as we do not expect the options to affect other proposed network expenditure.
- **Changes in safety costs**, as the identified need is not driven by network asset condition. 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.
- **Competition benefits**, as there is no competing generation affected by the limitations and risks being addressed by the options considered for this RIT-T.

[39] AER, Regulatory Investment Test for Transmission, November 2024, paragraphs 7 and 11.

7.4. Sensitivity studies

The robustness of the investment decision is tested using the range of input assumptions described in Table 23. This analysis varies the assumptions used for the central case as detailed in section 5.2.

Table 23: Input assumptions used for the sensitivity studies

PARAMETER	LOWER BOUND	CENTRAL 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
Maximum demand forecast	90% of revised 2025 maximum demand	100% of revised 2025 maximum demand	105% of revised 2025 maximum demand
Asset failure rate	80% of central	100% of central	120% of central
Value of customer reliability	80% of AER VCRs - site specific for SMTS	100% of AER VCRs - site specific for SMTS	120% of AER VCRs - site specific for SMTS
Discount rate	3.9% - regulatory discount rate	7.0% - AEMO IASR commercial discount rate	10.0% - AEMO IASR
Asset life	20 years	45 years	60 years

7.5. 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 23 with high uncertainty, as follows:

- **Central scenario –** adopting the central assumptions in Table 23;
- **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 24, 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. A heavier weighting is applied to the low scenario compared to the high scenario to reflect the current uncertainty and volatility in the global economy and its potential moderating effect on electricity maximum demand growth.

Table 24: Parameters with high uncertainty used for scenario modelling

PARAMETER	REASONING	LOW	CENTRAL	HIGH
Weighting		**25%**	**50%**	**25%**
Maximum demand forecast	Over the last decade there was significant uncertainty in forecasting maximum demand. Factors including economic growth, retail electricity prices, gas electrification, data centre load 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.	Lower Bound	Central Case	Higher Bound
Asset failure rate	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.	Lower Bound	Central Case	Higher Bound
Value of customer reliability	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.	Lower Bound	Central Case	Higher Bound

8. Options assessment

This chapter 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.

8.1. 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 market benefits of each option is presented in Table 25 based on their optimal timing.

Table 25: Calculated present value of gross benefits relative to base case ($ million, real 2025)

OPTION	LOW SCENARIO	CENTRAL SCENARIO	HIGH SCENARIO
1	0	0	0
3	165	860	2,019
4	166	864	2,031
5	168	868	2,034
6	156	834	1,974

8.2. Capital and operating costs

The estimated present value of capital, operating and maintenance costs of each option relative to the "Do Nothing" base case is presented in Table 26 based on their based on their optimal timing.

Table 26: 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
3	(44.3)	(44.3)	(44.3)
4	(57.1)	(57.1)	(57.1)
5	(63.2)	(63.2)	(63.2)
6	(192.5)	(192.5)	(192.5)

8.3. 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 27 based on their optimal timing.

Table 27: Calculated present value of net economic benefits relative to base case ($ million, real 2025)

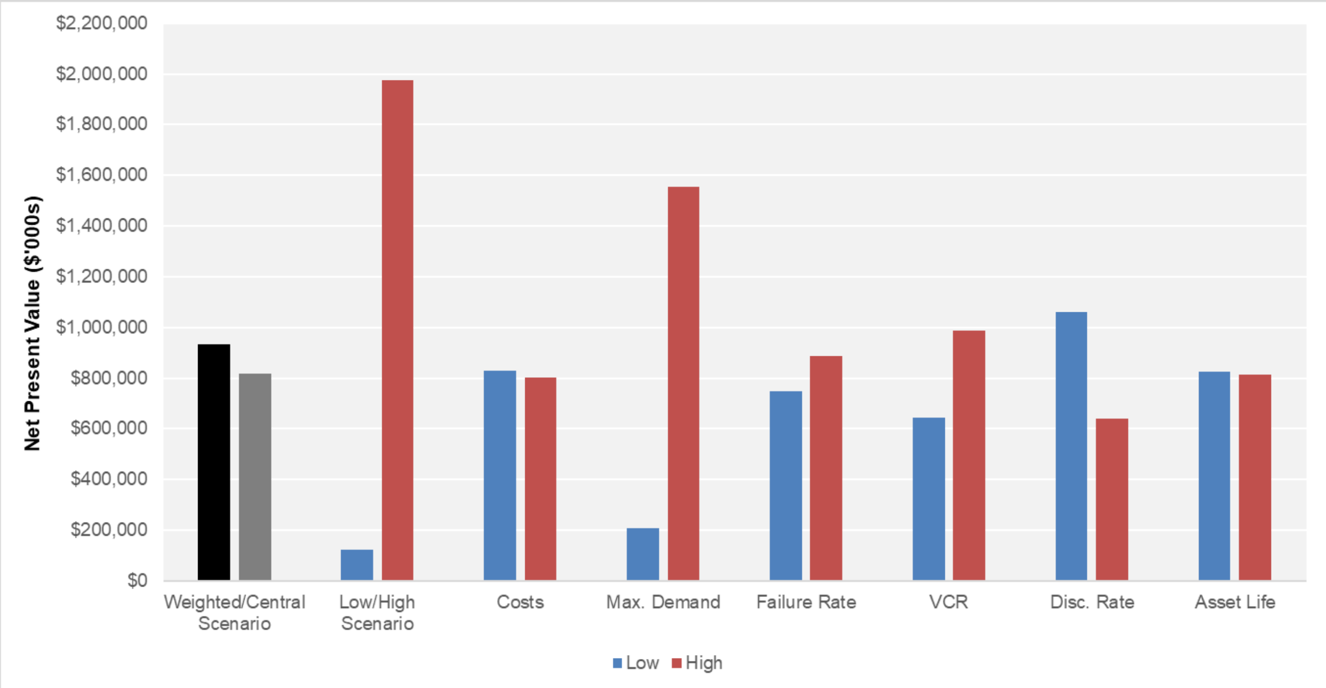
OPTION	LOW SCENARIO	CENTRAL SCENARIO	HIGH SCENARIO	WEIGHTED SCENARIO	
	25%	**50%**	**25%**	**100%**	**Rank**
1	0	0	0	0	5
3	121	816	1,975	932	1
4	109	807	1,974	924	2
5	105	805	1,971	922	3
6	(37)	641	1,781	757	4

8.4. Proposed preferred option

Given Option 3 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 3 as the proposed preferred option with an optimum timing of 2028-29.

The robustness of the proposed preferred option's net economic benefits to credible variations in key parameters (in Table 23), is demonstrated in the sensitivity study results of Figure 17.

Figure 17: NPV sensitivity analysis of the proposed preferred option ($ thousand, real 2025)



Under all credible sensitivities, the net present value of benefits remains positive for Option 3.

Option 3 satisfies the requirements of the RIT-T.

8.5. Optimal timing of the proposed preferred option

This section identifies and tests the robustness of the optimal timing of Option 3 for different assumptions of key parameters as detailed in Table 23. The changes in timing away from the optimal timing of 2028-29 for each of the sensitivities noting that that is the earliest timing from a constructability perspective, is presented in Table 28.

Table 28: Sensitivity of the optimal timing with respect to variation of key parameters

PARAMETER	LOWER BOUND	HIGHER BOUND
Capital and Operating Costs	2028-29 (no change)	2028-29 (no change)
Maximum demand forecast	2028-29 (no change)	2028-29 (no change)
Asset failure rate	2028-29 (no change)	2028-29 (no change)
Value of customer reliability	2028-29 (no change)	2028-29 (no change)
Discount rate	2028-29 (no change)	2028-29 (no change)
Asset life	2028-29 (no change)	2028-29 (no change)

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

9. Draft conclusion and next steps

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

9.1. Draft conclusion

The cost-benefit assessment undertaken for this PADR confirms that Option 3 (i.e., Install third 220/66 kV transformer at SMTS) is the proposed preferred option to meet the identified need. Option 3 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.

This option involves installing a third 220/66 kV 225 MVA transformer at SMTS to increase the thermal capacity ratings of the transmission connection assets at this terminal station. There is already provision in the original design of the terminal station to accommodate a third transformer.

This proposed preferred option is found to have positive net benefits under all scenarios investigated and on a weighted scenario basis will deliver $932 million in net economic benefits over the 10-year evaluation period. A sensitivity analysis was conducted on the net economic benefit to investigate the robustness of the conclusion to credible variations in key assumptions. It was identified that under all sensitivities, positive net benefits are maintained.

The optimal timing of the proposed preferred option is 2028-29 based on an estimated capital cost of $48.63 million (real, 2025) with annual operating and maintenance costs relating to this investment of approximately $0.5 million. This timing is constrained based on the construction lead time required for this option.

9.2. Next steps

AusNet and JEN invite written submissions and enquires on the matters set out in this PADR from interested stakeholders. All submissions and enquiries should be titled "***South Morang Supply Area RIT-T***" and directed to both:

Ali Kharrazi (AusNet)

Manager, Sub-Transmission Network Planning

Email: rittconsultations@ausnetservices.com.au

and

Hung Nguyen (JEN)

Network Planning Team Leader

Email: PlanningRequest@jemena.com.au

The consultation on this PADR is open for 6 weeks, consistent with the NER requirements[40]. Submissions are due on or before 22nd May 2026.

Submissions may be published on the Australian Energy Market Operator (AEMO), AusNet and JEN 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, AusNet and JEN will, having regard to any submissions received on the PADR, prepare and publish a project assessment conclusions report (PACR) including:

[40] NER, clause 5.16.4(r).

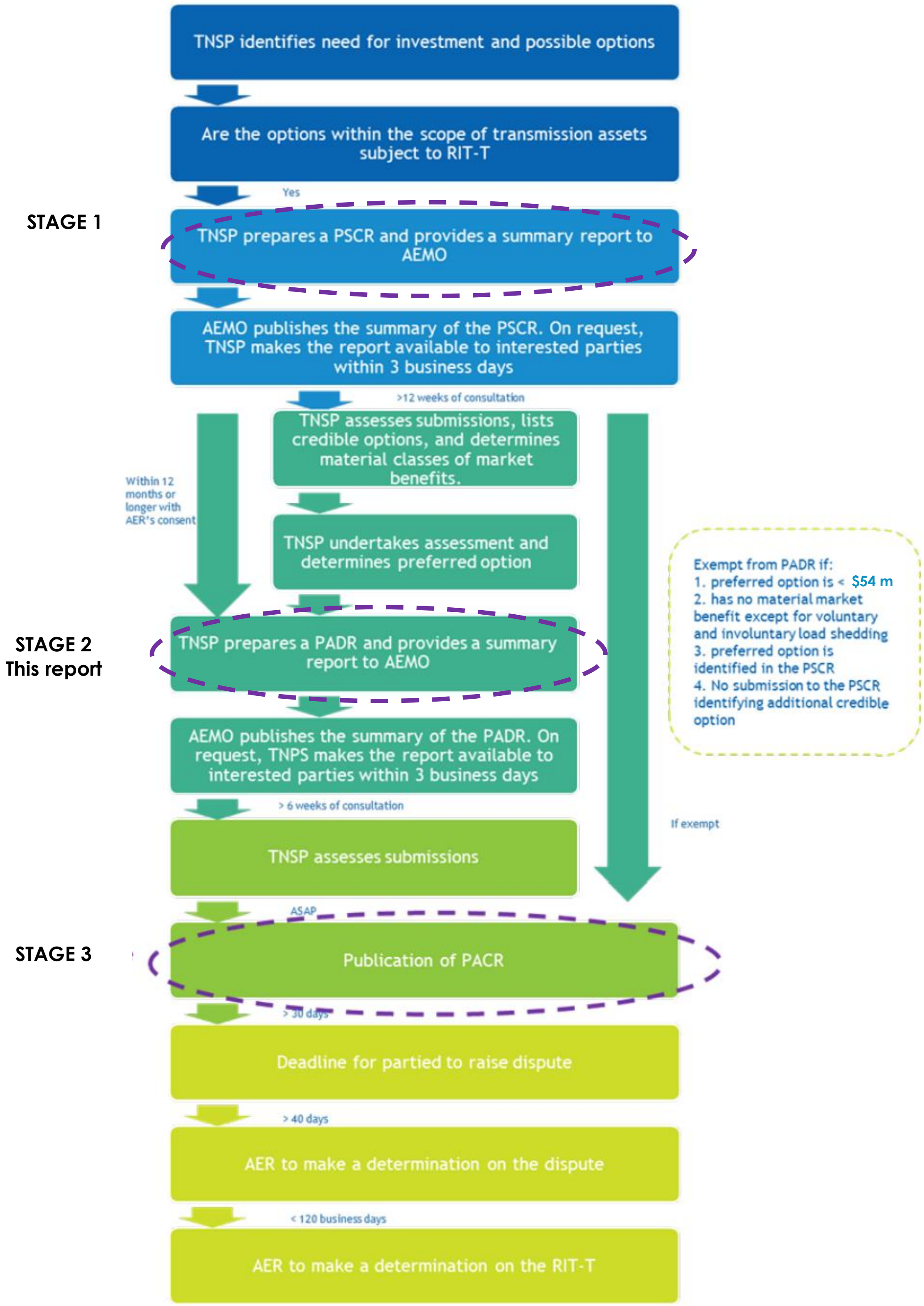
- a summary of, and commentary on, the submissions on the PADR;
- the matters detailed in the PADR; and
- confirming the preferred option to meet the identified need.

Publication of that report will conclude the RIT-T consultation.

AusNet and JEN intend on publishing the PACR by mid-2026.

A. RIT-T assessment and consultation process

Figure 18: RIT-T Process



B. RIT-T compliance checklist

This appendix sets out a checklist in Table 29 which demonstrates the compliance of this PADR with the requirements of clause 5.16.4(k) of the NER version 243.

Table 29: 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 6
(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Chapter 7
(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	
(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);	
(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Chapter 8
(8) the identification of the proposed preferred option;	
(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 proposed preferred option satisfies the regulatory investment test for transmission;	Chapter 9
(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 $103 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

AusNet Services

Level 31
2 Southbank Boulevard
Southbank VIC 3006
T +61 3 9695 6000
F +61 3 9695 6666
Locked Bag 14051 Melbourne City Mail Centre Melbourne VIC 8001
www.AusNetservices.com.au

Jemena Electricity Network

Level 16
567 Collins Street
Melbourne VIC 3000
T 1300 131 871
www.jemena.com.au