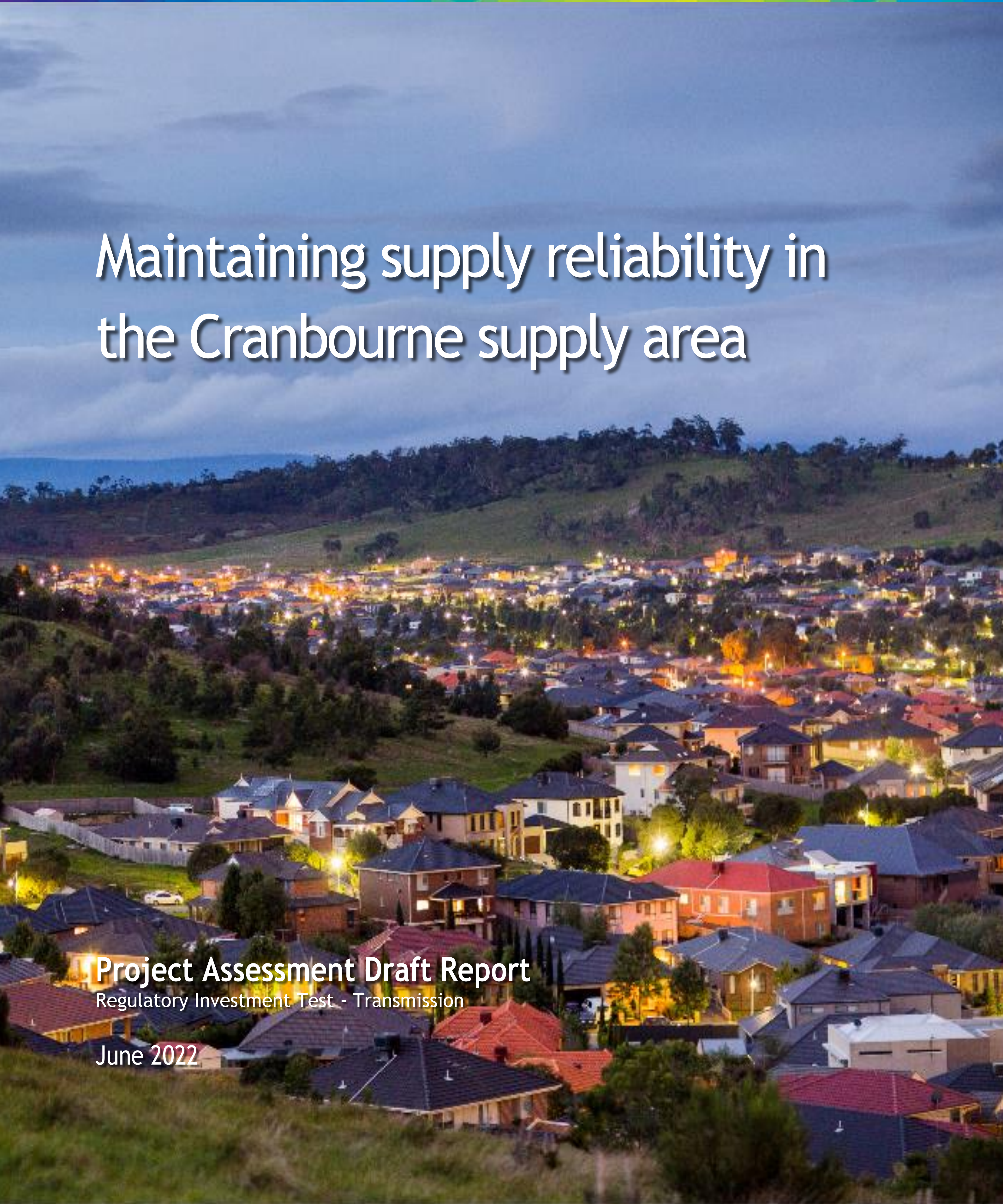
Maintaining supply reliability in the Cranbourne supply area



Project Assessment Draft Report

Regulatory Investment Test - Transmission

June 2022

Important notice

Purpose

AusNet and United Energy have prepared this document to provide information about potential limitations in the Victoria transmission network and options that could address these limitations.

Disclaimer

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Executive summary

AusNet and United Energy are regulated Victorian Distribution Network Service Providers (DNSPs) that provide electricity distribution services to more than 768,000 and 707,000 customers respectively. AusNet's electricity distribution network covers eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area, while United Energy's electricity distribution network covers the east and south-east Melbourne suburbs and the Mornington Peninsula.

In Victoria, the DNSPs have responsibility for planning and directing augmentation of the transmission connection assets that connect their distribution systems to the Victorian Declared Shared (Transmission) Network.

As expected by our customers and required by the various regulatory instruments that we operate under, AusNet and United Energy target investments that maintain current network service levels at the lowest possible cost for our customers. To achieve this, we assess options and develop plans, including the preparation of and consultation on Regulatory Investment Tests for Transmission (RIT-T), that aim to maximise the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

AusNet and United Energy is undertaking a RIT-T process to evaluate options to maintain reliability in the Cranbourne 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 Cranbourne Terminal Station (CBTS) that service the Cranbourne 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 CBTS. 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.

In June 2020, AusNet and United Energy 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 PCSR identified that the preferred network option to address the supply reliability need at CBTS, is the installation of a fourth 150 MVA 220/66 kV transformer (and associated switchgear) at CBTS.

During the PSCR consultation period, two non-network proposals were submitted, each providing a deferral option for the preferred network option. AusNet and United Energy have subsequently assessed the two non-network proposals and have prepared this report, the Project Assessment Draft Report (PADR)[3]. The PADR is the second stage of the RIT-T process in accordance with section 4.3 of the RIT-T Application Guidelines. It incorporates the assessment results of the non-network proposals, and provides draft conclusions of the RIT-T assessment, identifying the preferred option for addressing the identified need in the Cranbourne supply area.

Identified need

CBTS is owned and operated by AusNet and is located in Cranbourne in Melbourne's outer south eastern suburbs in Victoria. It was commissioned in the early 2000s and serves as the main

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[1] Australian Energy Market Commission, *"National Electricity Rules Version 164"* available at https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current, viewed on 18 May 2021.

[2] Australian Energy Regulator, *"Application guidelines Regulatory investment test for transmission"* available at https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf, viewed on 18 May 2021.

[3] On 8 September 2021, AusNet (and on behalf of United Energy) sought from the AER, an extension of the consultation period for this RIT-T under Clause 5.16.4(j) of the NER. This was granted by the AER on 9 December 2021 with an extension for publication of the PADR to 25 June 2022.

transmission connection point for distribution of electricity to customers to those parts within the AusNet and United Energy distribution service areas incorporating the Cranbourne supply area.

CBTS provides electricity supply to more than 187,000 customers, which are primarily residential with some light industrial and commercial customers. The geographic area supplied by CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west. Electricity demand in the CBTS geographic area has been amongst the fastest growing regions in Victoria and this terminal station has now reached its capacity. The summer peak actual demand increased by 172 MVA between 2007-08 and 2019-20, which represents an average annual growth rate of 4.1 per cent. Actual maximum demand on CBTS during the summers of 2020-21 and 2021-22 reached 422.8 MVA and 448.9 MVA respectively.

The identified need is to maintain electricity supply reliability for customers in the area supplied by CBTS, the Cranbourne supply area. Continuing forecast growth in maximum demand in the area, will rapidly increase the level of EUE, deteriorating reliability of supply for customer due to insufficient supply capacity available at CBTS. Addressing this identified need will result in an increase in the producer and consumer surplus (a net economic benefit to all those who produce, consume and transport electricity in the NEM) by reducing the cost of EUE by more than the preferred option's implementation and ongoing operating and maintenance costs.

The need for this investment has been foreshadowed in the 2021 Transmission Connection Planning Report (TCPR), published jointly by the Victorian DNSPs.

Credible options

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

- Option 1 - Do nothing (status-quo);
- Option 2 - Non-network solutions;
- Option 3 - Install a fourth 150 MVA 220/66 kV transformer at CBTS;
- Option 4 - Install two 50 MVAr 66 kV capacitor banks at CBTS;
- Option 5 - Establish new 22 kV distribution feeders to offload CBTS; and
- Option 6 - Establish a new 220/66 kV terminal station.

The PSCR previously identified Option 3 as the preferred network option that maximises the net market benefits.

Two non-network proposals were received during the RIT-T PSCR consultation, and these are individually assessed for this PADR as two credible non-network solutions under Option 2 to address the identified need as follows:

- Option 2a – Enel X non-network proposal;
- Option 2b – Firm Power non-network proposal.

Assessment approach

AusNet and United Energy 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.

The robustness of the ranking and optimal timing of options have 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.

Scenario analysis has been informed by AEMO's Integrated System Plan's (ISP) inputs, assumptions and scenarios.

Options assessment and draft conclusion

The cost-benefit economic evaluation assessment undertaken for this PADR has reconfirmed that preferred option to address the identified need for this RIT-T is Option 3 (Install a fourth 150 MVA 220/66 kV transformer at CBTS).

This preferred option is found to have positive net benefits under all scenarios and sensitivities investigated, and on a weighted basis will deliver $241.7 million in present value net economic benefits over the lifecycle. A summary of the net present value analysis for each option and each scenario is provided in Table 1, noting that Options 2, 4 and 5 are followed by Option 3 as they act to defer the need for Option 3 (the preferred network option).

Option	Low Scenario	Central Scenario	High Scenario	Weighted	Rank
Weighting	*40%*	*50%*	*10%*	*100%*	
Option 1	0	0	0	0	7
Option 2a	46.76	319.47	631.00	241.54	2
Option 2b	40.87	315.86	630.00	237.28	5
Option 3	47.05	319.66	630.58	**241.71**	**1**
Option 4	45.58	319.55	630.77	241.09	3
Option 5	46.59	319.17	624.91	240.71	4
Option 6	(64.51)	199.50	492.62	123.21	6

Table 1 – Present value of net economic benefits relative to base case ($ million, real 2022)

The analysis undertaken and the identification of Option 3 as the preferred option satisfies the requirements of the RIT-T. Option 3 is the 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 to all those who produce, consume and transport electricity in the NEM.

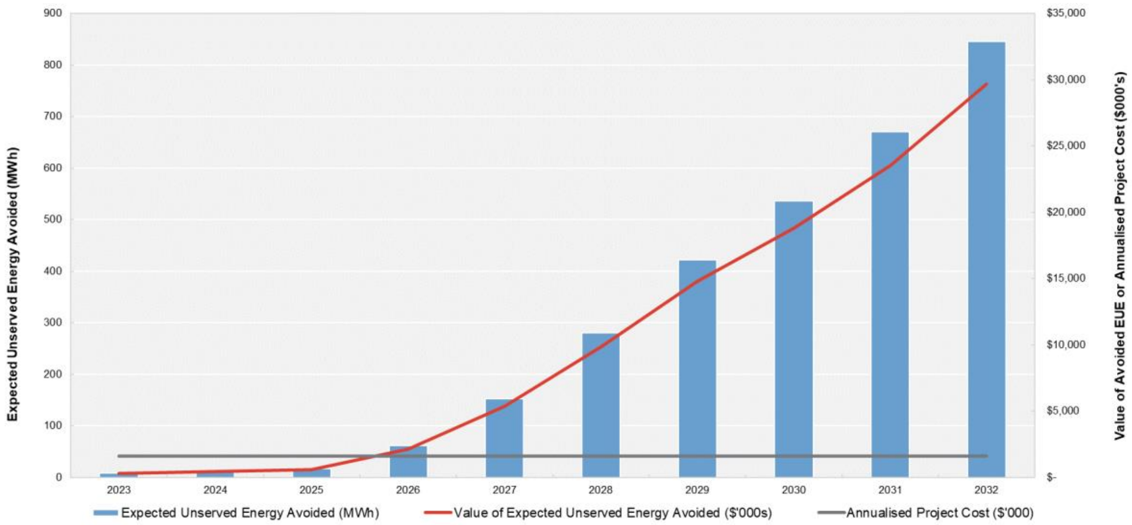

Figure 1 - Option 3 optimal timing based on avoided risks and annualised costs

As shown in Figure 1, the optimal timing of the preferred option is 2025-26 based on an estimated capital cost of $23.2 million ±25 per cent (real, 2022) with annual operating and maintenance costs relating to this investment of approximately $0.23 million.

A sensitivity analysis was conducted on the net economic benefit as shown in Figure 2 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.

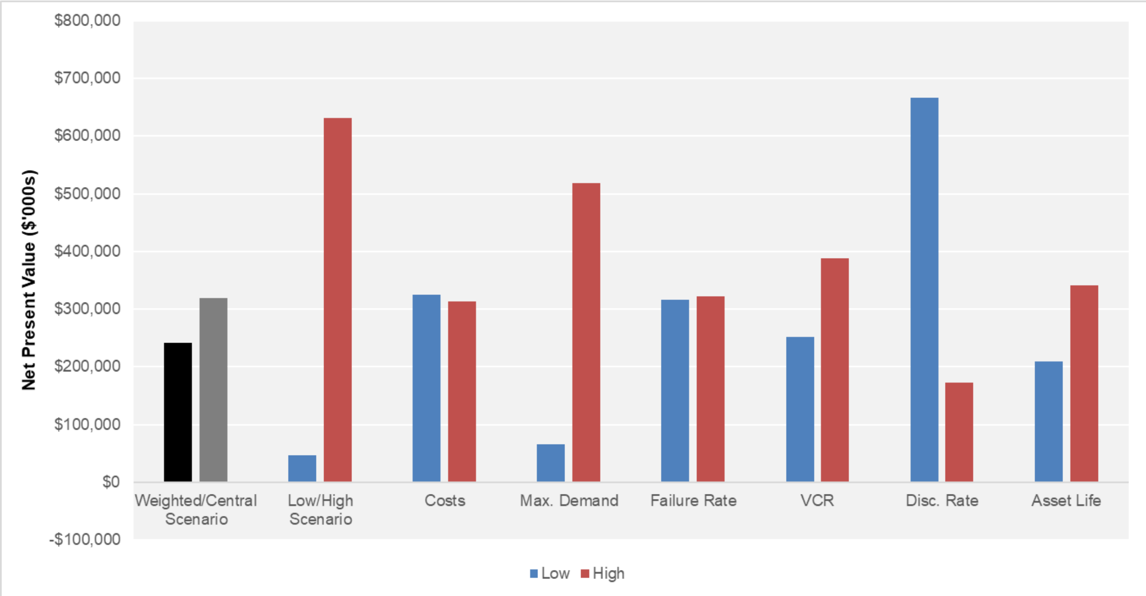

Figure 2 - NPV sensitivity analysis of the preferred option ($ thousand, real 2022)

Submissions

AusNet and United Energy welcome written submissions on the issues and the credible options presented in this PADR. Submissions should be emailed to rittconsultations@ausnetservices.com.au and planning@ue.com.au on or before 8th August 2022. In the subject field, please reference 'RIT-T PADR Cranbourne Terminal Station.'

Submissions will be published on the Australian Energy Market Operator (AEMO), AusNet and United Energy 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

Assessments of the options and responses to this PADR will be presented in the Project Assessment Conclusions Report (PACR) that is intended to be published before 31st December 2022.

Contact

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1. Introduction

AusNet and United Energy are undertaking this Regulatory Investment Test for Transmission (RIT-T) to evaluate options to maintain reliability of supply in the Cranbourne supply area. 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 Cranbourne Terminal Station (CBTS).

The Project Specification Consultation Report (PSCR) for this RIT-T was published in June 2020 in accordance with clause 5.16 of the National Electricity Rules (NER)[4] and section 4.2 of the RIT-T Application Guidelines.[5]

AusNet and United Energy received submissions comprising of two non-network proposals during the RIT-T PSCR consultation stage as follows:

- Enel X Australia Pty. Ltd. received on 25th September 2020; and
- Firm Power Pty. Ltd., received on 26th September 2020.

Publication of this Project Assessment Draft Report (PADR) represents the second stage of the RIT-T process[6] in accordance with section 4.3 of the RIT-T Application Guidelines. It provides information about the draft conclusions of the RIT-T, and incorporates the assessment results of the non-network proposals, to identify the preferred option for addressing the identified need in the Cranbourne supply area.

The structure of this PADR is as follows:

- **Chapter 2** provides a description of the identified need;
- **Chapter 3** describes the 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 AusNet and United Energy 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 preferred option and its optimal timing, along with scenario and sensitivity analysis results to confirm the robustness of the preferred option to credible changes in assumptions; and
- **Chapter 8** presents the conclusions of the PADR and details of the proposed preferred option.

The need for investment has been foreshadowed in the 2021 Transmission Connection Planning Report (TCPR), published jointly by the Victorian DNSPs[7].

[4] Australian Energy Market Commission, *"National Electricity Rules Version 180"* available at https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current.
[5] Australian Energy Regulator, *"Application guidelines Regulatory investment test for transmission August 2020"* available at https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf.
[6] A RIT-T process will assess the economic efficiency and technical feasibility of proposed network and non-network options.
[7] Victorian Distribution Network Service Providers, *"Transmission Connection Planning Report 2021"* available at https://media.unitedenergy.com.au/factsheets/Transmission-Connection-Planning-Report-2021.pdf.

2. Identified need

The role of CBTS in providing electricity network services is discussed in this chapter. Quantification of the risk costs associated with the forecast increase in EUE for the status-quo, and the need for the investments is also presented.

2.1. Cranbourne supply area

CBTS is the terminal station that supplies the Cranbourne area and its surrounds. CBTS was originally established with two 150 MVA 220/66 kV transformers as a new terminal station in 2005 to reinforce the security of supply for the Cranbourne supply area, serviced by East Rowville Terminal Station (ERTS) at the time. In 2009, a third 150 MVA 220/66 kV transformer was commissioned at CBTS to supply further growth of electricity demand in the area.

The geographic area supplied by CBTS spans from Narre Warren in the north to Clyde in the south, and from Pakenham in the east to Carrum and Frankston in the west, as shown in Figure 3. CBTS supplies the AusNet and United Energy distribution networks with a split of 61 per cent and 39 per cent respectively, based on average annual energy consumption.

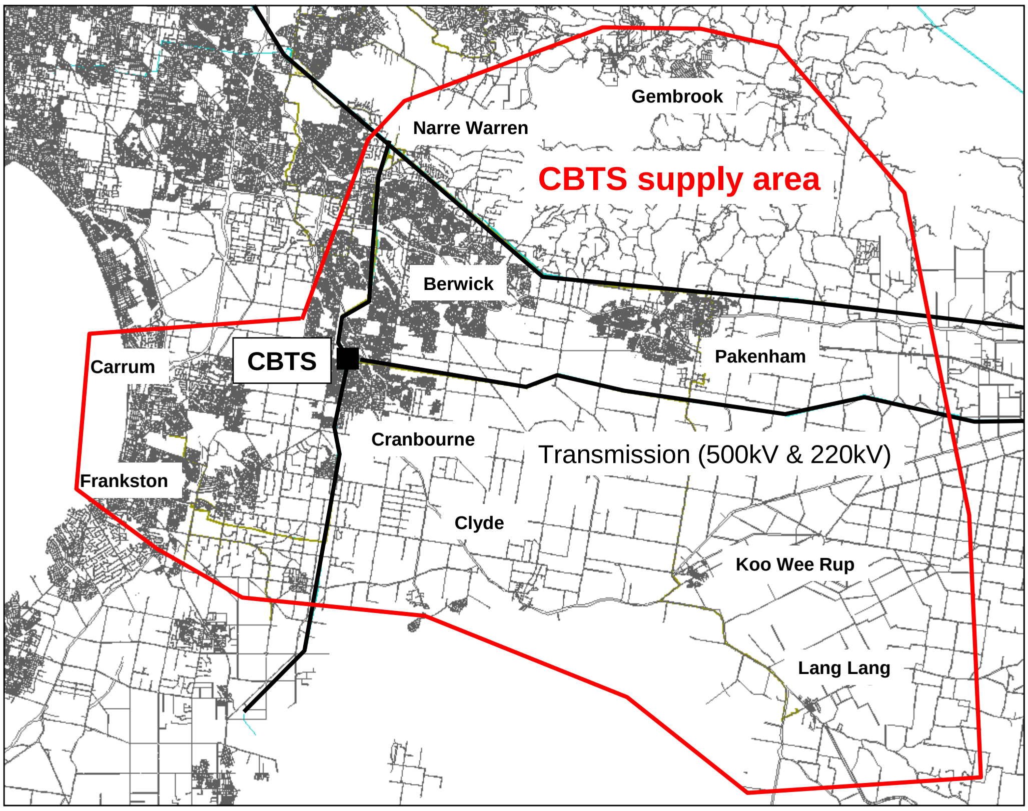

Figure 3 - Cranbourne supply area

Customer demand for electricity

More than 187,000 customers currently rely on CBTS for their electricity supply. Growth in customer numbers in the supply area has been substantial over the last several years, given CBTS services Melbourne's outer south-eastern growth corridor. Customer number growth has averaged at 5,695 additional customers per annum since 2014, an average annual increase of 3.8 per cent.

Commercial customers consume 41 per cent and residential customers consume 51 per cent of the total annual energy supplied at CBTS as illustrated in Table 1.

Customer type	Share of consumption (%)
Commercial	40.7
Residential	50.9
Industrial	5.9
Agricultural	2.5
Total	100

Table 2 - CBTS net energy consumption composition

CBTS is a summer-peaking terminal station. Electricity demand in the CBTS geographic area has been amongst the fastest growing regions in Victoria and this is directly related to the strong growth in customer numbers within the supply area. The summer peak actual demand increased by 172 MVA between 2007-08 and 2019-20, which corresponds to an average annual growth rate of 14 MVA or 4.1 per cent.

In 2019-20 the summer maximum demand on CBTS reached 470.6 MW (481.9 MVA), which is the highest annual maximum demand on record, coinciding with extreme ambient temperatures on the day. The recorded maximum demand in summer 2020-21 was 412.0 MW (422.8 MVA) reflecting milder ambient temperature conditions. The CBTS net load is expected to have a power factor of 0.97 at a POE10[8] maximum demand. Demand at CBTS is expected to exceed 95 per cent of the POE50[9] maximum demand for 2 hours per annum.

Electricity network servicing the supply area

CBTS currently has three parallel 150 MVA 220/66 kV transformers and three 66 kV buses. A simplified single line diagram of CBTS is provided in Figure 4.

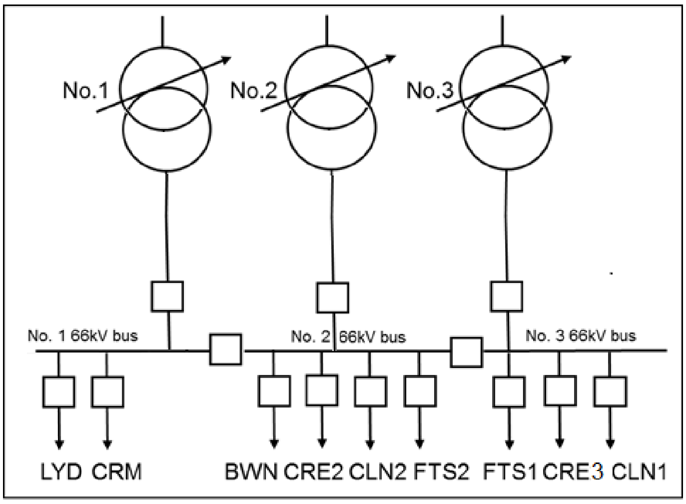

Figure 4 – CBTS existing transmission connection assets single line diagram

CBTS has nine 66 kV sub-transmission line exits supplying eight AusNet zone substations, Cranbourne (CRE), Lysterfield (LYD), Narre Warren (NRN), Pakenham (PHM), Officer (OFR), Berwick North (BWN), Lang Lang (LLG) and Clyde North (CLN), and three United Energy zone substations, Carrum (CRM), Langwarrin (LWN) and Frankston (FTN) in a loop via Frankston Terminal Station (FTS).

8 A POE10 forecast indicates a temperature condition where there is 10 % likelihood that actual maximum demand will be greater.
9 A POE50 forecast indicates a temperature condition where there is 50 % likelihood that actual maximum demand will be greater.

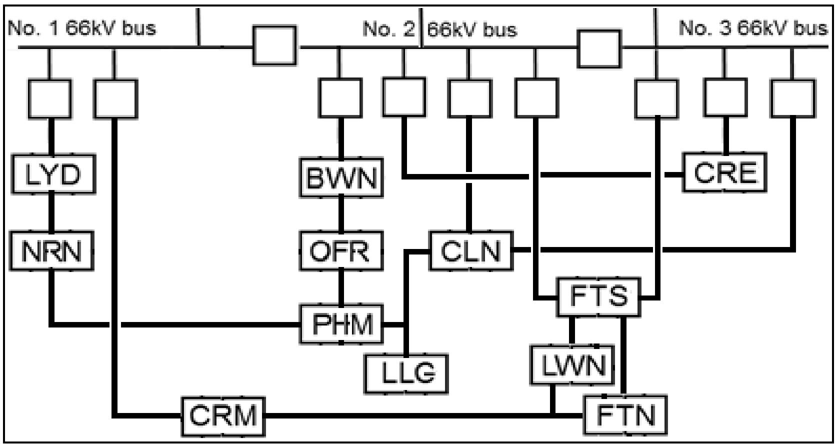

Figure 5 – CBTS existing sub-transmission network schematic diagram

2.2. Description of the identified need

The identified need is to maintain electricity supply reliability for customers within the Cranbourne supply area. Due to maximum demand growth in the area, supply reliability is forecast to deteriorate, resulting in increased levels of EUE for customers supplied from the CBTS transmission connection assets. Addressing this identified need will result in an increase in the producer and consumer surplus (a net economic benefit to all those who produce, consume and transport electricity in the NEM) by reducing the cost of EUE by more than the preferred option's implementation and ongoing operating and maintenance costs.

There are two drivers of EUE at CBTS - a lack of "N" capacity, and a lack of "N-1" capacity. Table 3 summarises the forecast "N" system normal limitations at CBTS.

Year[10]	POE10		POE50		Probability Weighted[11]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	6.2	2	0.0	0	0.0	0.00
2024	19.0	9	0.0	0	0.0	0.00
2025	29.9	13	0.0	0	0.6	0.02
2026	43.8	18	0.0	0	41	1.44
2027	57.7	23	0.0	0	131	4.59
2028	70.5	26	0.0	0	259	9.11
2029	84.1	29	0.0	0	401	14.1
2030	97.1	32	0.0	0	513	18.0
2031	110.9	35	9.6	1	644	22.6
2032	126.7	38	23.0	2	816	28.6

Table 3 - CBTS capacity limitations (EUE for "N" condition)

[10] Financial year ending 30th June.
[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 distribution feeders load transfer capabilities.

There is now insufficient capacity to supply the growing demand at CBTS from 2022-23 under system normal ("N") operating conditions for a POE10 maximum demand, with 6.2 MVA of load-at-risk next summer. The station N rating is expected to be reached under a POE50 forecast from summer 2030-31. Load transfers to manage the "N" load-at-risk become exhausted from 2024-25, providing an EUE in that summer of approximately 0.6 MWh. This EUE is estimated to have a value to consumers of around $0.02 million (real, 2022). The risk rises rapidly thereafter with an EUE in 2025-26 of approximately 41 MWh with a value of $1.44 million (real, 2022).

Table 4 provides a summary of the forecast "N-1" contingency condition capacity limitations at CBTS (i.e., excluding the "N" system normal limitations presented above).

Year[12]	POE10		POE50		Probability Weighted[13]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	180.0	107	106.9	52	8.8	0.31
2024	180.0	119	118.2	61	12.4	0.43
2025	180.0	130	126.9	69	16.6	0.58
2026	180.0	144	137.9	81	20.5	0.72
2027	180.0	157	149.2	93	22.1	0.78
2028	180.0	176	160.0	104	21.4	0.75
2029	180.0	196	171.6	117	21.3	0.75
2030	180.0	214	182.3	129	24.2	0.85
2031	180.0	233	184.0	141	27.5	0.97
2032	180.0	261	184.0	155	31.6	1.11

Table 4 - CBTS capacity limitations (EUE for "N-1" condition)

The historical and forecast maximum demand under a transformer outage scenario ("N-1") has exceeded the station rating since 2011-12, with levels of "N-1" load-at-risk during peak loading periods now reaching the full transformer capacity of 180 MVA from next summer for a POE10 forecast maximum demand. For an outage of one 220/66 kV transformer at CBTS, there will be insufficient capacity at this terminal station to supply all demand at the POE10 forecast maximum demand for about 107 hours in 2022-23, and 52 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, contributing to an expected unavailability per transformer per annum of 0.22 per cent. When the energy-at-risk is weighted by this low unavailability, and emergency load transfer capability is considered, the EUE is estimated to be around 8.8 MWh in 2022-23. This EUE is estimated to have a value to consumers of around $0.31 million (real, 2022). By 2025-26, this increases to 20.5 MWh and $0.72 million (real, 2022).

The estimates of EUE and its financial value are based on an assumption of a 70% weighting of moderate temperatures (POE50) occurring in each year, and a 30% weighting of higher temperature conditions (POE10), using a value of customer reliability of $35,117/MWh.

The key elements of the "Do Nothing" supply reliability risk under the status-quo are shown in Figure 6 for both "N" and "N-1" conditions, ignoring the effects of available load transfer capability.

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[12] Financial year ending 30th June.

[13] 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.

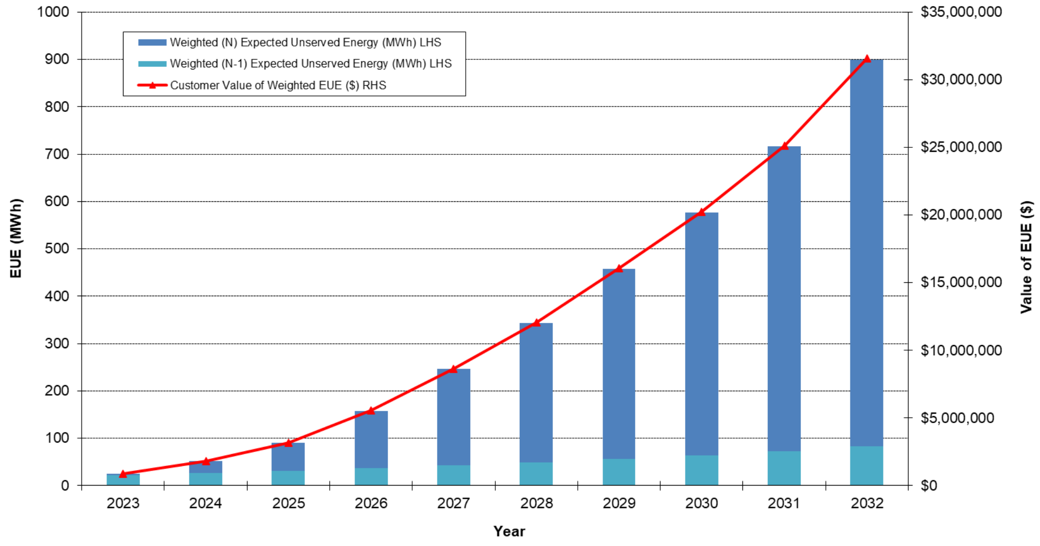

Figure 6 – CBTS EUE risk costs (ignoring the effects of available load transfer capability)

It is acknowledged that CBTS has load transfer capability available at both the 22 kV distribution feeder level and at the 66 kV sub-transmission level. This capability allows AusNet and United Energy to manage risk in the short-term, by transferring load away from CBTS to surrounding terminal stations using spare capacity available through each distribution network.

Taking into account this available load transfer capability, the reduced supply reliability risks are shown in Figure 5 for both "N" and "N-1" conditions. This reduction in risk provided by the load transfer capability effectively delays the timing of other credible options by two years.

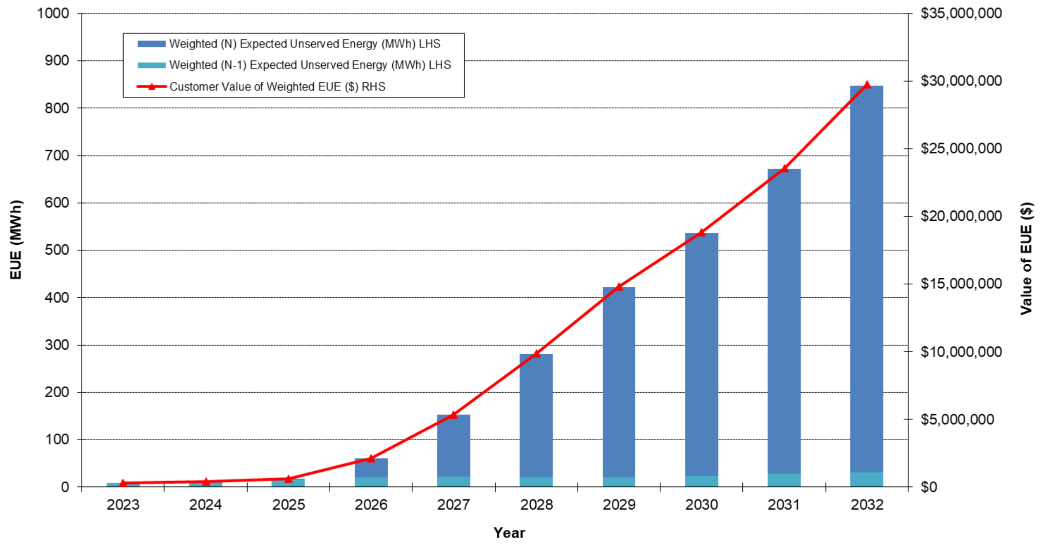

Figure 7 – CBTS EUE risk costs (including the effects of available load transfer capability)

It can be seen in both cases that it is the EUE associated with the "N" capacity of CBTS that is driving the bulk of the risk cost within the next few years.

By undertaking one of the options identified in this RIT-T, AusNet and United Energy will be able to avoid this projected deterioration in supply reliability for the Cranbourne supply area.

3. Credible options assessed

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

- **Option 1 - Do Nothing (base case)** continues to supply customers serviced by CBTS 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 2 - Non-network solutions** is to contract network support services, within the distribution networks serviced by CBTS, to reduce the net maximum demand on CBTS and address the identified need. 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;
- **Option 3 - Install a fourth 150 MVA 220/66 kV transformer at CBTS** to increase the thermal capacity of the transmission connection assets to address the identified need. There is already provision to accommodate a fourth transformer at CBTS, and would involve a fourth 66kV bus and rearrangements of the existing 66 kV sub-transmission feeders within the terminal station;
- **Option 4 - Install two 50 MVAr 66 kV capacitor banks at CBTS** to reduce the net maximum demand on CBTS to address the identified need. There is provision to accommodate capacitor banks at CBTS, and would involve extension of the 66 kV buses within the terminal station;
- **Option 5 - Establish new 22 kV distribution feeders to offload CBTS** in order to maintain the maximum demand on CBTS 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 United Energy's Mordialloc and Frankston South zone substations, located just outside of the supply area, to offload CBTS; and
- **Option 6 - Establish a new 220/66 kV terminal station** in the Pakenham area (site yet to be identified)[14] to reduce the maximum demand on CBTS, 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 PSCR identified Option 3 as the preferred network option that maximises the net market benefits.

Two non-network proposals were received during the RIT-T PSCR consultation, and these are individually assessed in this PADR as two credible non-network solutions under Option 2 to address the identified need as follows:

- **Option 2a** – Enel X non-network proposal; and
- **Option 2b** – Firm Power non-network proposal.

Both proposals plan to defer (rather than avoid) the preferred network option by utilising non-network solutions.

[14] or at the future Narre Warren or Pearcedale North terminal station sites.

4. Submissions to the PSCR

This chapter provides a summary of, and commentary on, the submissions to the PSCR. AusNet and United Energy received only two submissions during the RIT-T PSCR consultation stage, comprising of two non-network proposals as follows:

- A non-network proposal was submitted to AusNet and United Energy from Rando Yam, Manager Flexibility Operations of Enel X Australia Pty. Ltd. on 25th September 2020; and
- A non-network proposal was submitted to AusNet and United Energy from Nick Rose, General Manager of Firm Power Pty. Ltd. on 26th September 2020.

The details of each of these non-network proposals is summarised below[15].

4.1. Enel X non-network proposal

Enel X operates the largest Virtual Power Plant (VPP) in Australia, providing network support to transmission and distribution operators, ancillary services, grid support during periods of extreme wholesale prices, and emergency reserves to AEMO via the RERT programmes. Enel X's VPP provides these services using existing assets sited at their customers' commercial and industrial sites. Enel X aggregates and orchestrates these assets to curtail demand on the grid (through reducing load or utilising on-site backup generation), providing demand response.

Enel X proposes to provide non-network support to AusNet and United Energy to allow for deferral of augmentation to the CBTS transmission connection assets using 3MW of demand response capacity for the summers of 2022-23, 2023-24 and 2024-25 within the Cranbourne supply area. This will be built from a portfolio of sites that either already participate in Enel X's VPP or sign up to participate in the VPP before the commencement of the programme.

Enel X's VPP proposes to reduce load on the grid in a predictable, repeatable fashion when a dispatch instruction is provided. During the time between dispatch instruction and required time of dispatch start, it is intended Enel X's customers will reduce the load as seen from the electricity metering point. Onsite backup generation will provide the load for the required duration of the dispatch.

4.2. Firm Power non-network proposal

Firm Power specialises in providing embedded energy storage solutions as a non-network solution to network limitations and constraints. Firm Power was awarded a grant under the NSW Emerging Energy Program to develop two battery energy storage systems in Western Sydney as a way of deferring network investment to meet peak summer loads.

Firm Power proposes to provide non-network support to AusNet and United Energy to allow for deferral of augmentation to the CBTS transmission connection assets, whilst ensuring maintenance of electricity supply reliability to meet the identified need of the customers within the geographic area, and to deliver an optimal present value of net economic benefit. It will achieve this by installing a utility scale battery (BESS) on land leased from AusNet within the CBTS supply area to provide 30MW/45MWh of battery storage capacity (scalable over time), connected at 22 kV from the summer of 2023-24, to reduce the EUE associated with the CBTS "N" thermal capacity limitation only.

Firm Power's BESS is a dispatchable system that is controllable to operate at specific times, but has storage limitations. *(sentence deleted at request of Firm Power)*. When in network-support operation, the BESS will operate to reduce peak demand to mitigate EUE at CBTS. It is intended the BESS will charge when the system has low load.

[15] Note: All milestone dates quoted within the non-network proposals have been deferred by one year in this RIT-T assessment due to the later than expected release of this PADR, having regard to the lead times required to implement the proposed non-network solutions. The dates quoted in this PADR reflect this adjustment.

5. Credible options costs and benefits

AusNet and United Energy have considered both network and non-network options to address the identified need at CBTS. The scope, costs and benefits of each of the options are presented below.

5.1. Option 1 – Do nothing

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

This option is expected to lead to significant supply interruptions and deteriorating supply reliability under both “N” and “N-1” conditions at times of maximum demand, because of capacity shortfalls at CBTS.

As detailed in Table 3 and Table 4 for the supply reliability risk associated with the “N” and “N-1” conditions respectively, the total combined value of the EUE risk associated with the “Do nothing” option as shown in Figure 7, is forecast to increase from $0.31 million in 2022-23 to $29.8 million by 2031-32 (real, 2022).

In the context of this RIT-T, the “Do nothing” option 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. 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 solutions

Non-network options contract to provide network support services, from within the distribution or sub-transmission networks serviced by CBTS, to reduce the net maximum demand on CBTS and address the identified need. 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.

Two credible non-network options have been identified through consultation on the PSCR, and these are detailed below.

5.2.1. Option 2a – Enel X non-network proposal

Section deleted at request of Enel X

5.3. Option 2b – Firm Power non-network proposal

Section deleted at request of Firm Power.

5.4. Option 3 - Install a 4th 220/66 kV transformer at CBTS

This option involves installing a fourth 150 MVA 220/66 kV 150 MVA transformer at CBTS 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 fourth transformer. The scope of works would also involve installing a fourth 66kV bus with a ring connection, and rearrangements of the existing 66 kV sub-transmission feeders within the terminal station to allow CBTS to operate with the 66 kV bus split into a B12 and a B34 group, so that maximum short circuit levels can be maintained within equipment ratings.

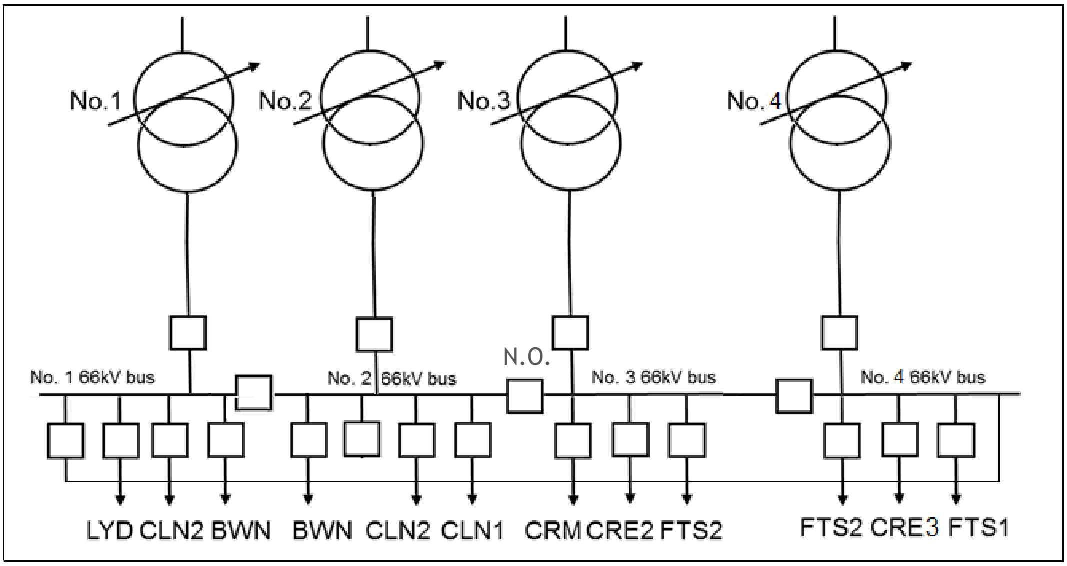

Figure 8 – CBTS proposed transmission connection assets single line diagram (Option 3)

The scope of work required for this option includes:

- a new fourth 150 MVA 220/66 kV transformer to the west of the existing transformers, including firewalls;
- a new 220 kV circuit breaker, bay and rack;
- extending the No.1 66 kV bus with two new circuit breakers and establish a new No.4 66 kV bus with five new 66 kV circuit breakers;
- a neutral earth reactor at the new fourth transformer 66 kV neutral that matches the neutral earth reactors at all existing transformers;
- a new auto-reclose scheme, which will provide for parallel operation of three transformers in the event of a transformer or bus outage;
- a new 66kV ring bus to link the No.1 and No.4 66kV bus;
- relocation of AusNet and United Energy 66 kV feeder exits as shown in Figure 8 with BWN, LYD, CLN loops on 1-2 bus (B12) group and CRE, FTS, CRM on 3-4 bus (B34) group. Three feeders (BWN, CLN2 and FTS2) are to be double switched; and
- replacement of line protection at CRE and CLN to match new line double-switched protection at CBTS.

Table 5 presents the forecast “N” system normal limitations at CBTS with Option 3 in service.

Year[16]	POE10		POE50		Probability Weighted[17]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	6.2	2	0.0	0	0.0	0.00
2024	19.0	9	0.0	0	0.0	0.00
2025	29.9	13	0.0	0	0.6	0.02
2026	0.0	0	0.0	0	0.0	0.00
2027	0.0	0	0.0	0	0.0	0.00
2028	0.0	0	0.0	0	0.0	0.00
2029	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00

Table 5 - CBTS capacity limitations with Option 3 in service (EUE for "N" condition)

Table 6 provides a summary of the forecast "N-1" contingency condition capacity limitations at CBTS (i.e., excluding the "N" system normal limitations presented above) with Option 3 in service.

Year[18]	POE10		POE50		Probability Weighted[19]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	180.0	107	106.9	52	8.8	0.31
2024	180.0	119	118.2	61	12.4	0.43
2025	180.0	130	126.9	69	16.6	0.58
2026	43.8	18	0.0	0	0.3	0.01
2027	57.7	23	0.0	0	0.5	0.02
2028	70.5	26	0.0	0	0.7	0.03
2029	84.1	29	0.0	0	1.0	0.03
2030	97.1	32	0.0	0	1.3	0.04
2031	110.9	35	9.6	1	1.6	0.06
2032	126.7	38	23.0	2	2.0	0.07

Table 6 - CBTS capacity limitations with Option 3 in service (EUE for "N-1" condition)

This option meets the identified need by alleviating the supply capacity risk and removing nearly all the expected unserved energy at CBTS, after installation of the fourth transformer at CBTS, over the next ten years. Compared to "Do nothing", only 0.2% of the supply capacity risk (i.e., the expected unserved energy) remains on CBTS by 2032 with this option in place.

[16] Financial year ending 30th June.
[17] 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.
[18] Financial year ending 30th June.
[19] 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.

The estimated capital cost of this network option is $23.2 million (real 2022) which has an annualised cost of $1.58 million. The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing of summer 2025-26 as shown in Figure 9.

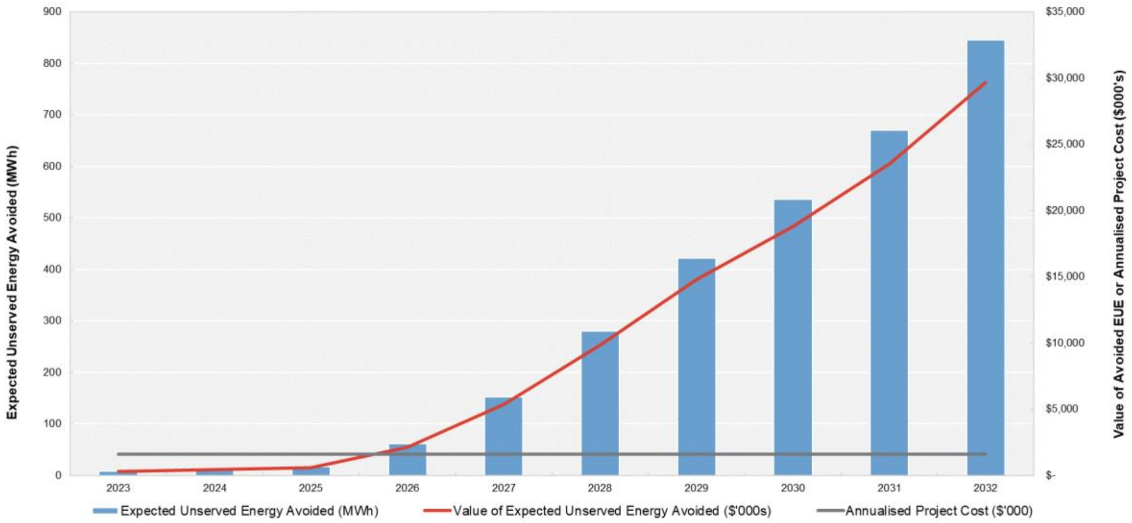

Figure 9 – Option 3 optimal timing based on avoided risks and annualised costs

5.5. Option 4 - Install two 50 MVAr 66 kV capacitor banks

This option involves installing two 50 MVAr 66 kV capacitor banks to reduce the net maximum demand on CBTS and delay the identified need. There is provision to accommodate capacitor banks at CBTS and this would involve extension of the existing 66kV buses within the terminal station.

Currently, CBTS operates at a power factor of approximately 0.97 lagging in summer and does not have any 66 kV capacitor banks. Two 50 MVAr 66 kV capacitor banks installed will reduce POE10 maximum demand by approximately 16 MVA and could defer the preferred network option (Option 3) by one year given the average growth rate is around 14 MVA per annum.

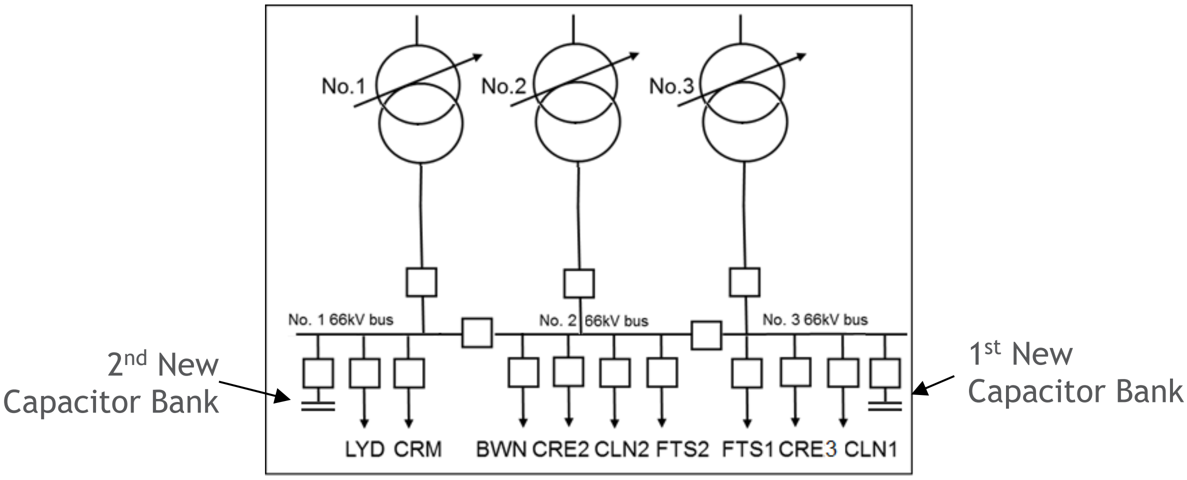

Figure 10 - CBTS proposed transmission connection assets single line diagram (Option 4)

Table 7 provides a summary of the forecast "N" system normal condition capacity limitations at CBTS with Option 4 in service.

Year[20]	POE10		POE50		Probability Weighted[21]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	6.2	2	0.0	0	0.0	0.00
2024	19.0	9	0.0	0	0.0	0.00
2025	15.2	8	0.0	0	0.0	0.00
2026	28.7	12	0.0	0	5.1	0.18
2027	42.2	17	0.0	0	60	2.09
2028	54.7	22	0.0	0	153	5.39
2029	67.9	26	0.0	0	275	9.67
2030	80.6	28	0.0	0	373	13.1
2031	93.9	31	0.0	0	485	17.0
2032	109.0	34	7.9	1	625	22.0

Table 7 - CBTS capacity limitations with Option 4 in service (EUE for "N" condition)

[20] Financial year ending 30th June.
[21] 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.

Table 8 provides a summary of the forecast "N-1" contingency condition capacity limitations at CBTS (i.e., excluding the "N" system normal limitations presented above) with Option 4 in service.

Year[22]	POE10		POE50		Probability Weighted[23]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	*180.0*	*107*	*106.9*	*52*	*8.8*	*0.31*
2024	*180.0*	*119*	*118.2*	*61*	*12.4*	*0.43*
2025	180.0	115	114.2	57	11.0	0.39
2026	180.0	129	124.9	66	15.6	0.55
2027	180.0	143	135.9	79	17.9	0.63
2028	180.0	155	146.3	90	18.1	0.64
2029	180.0	172	157.6	101	18.0	0.63
2030	180.0	190	168.1	113	20.5	0.72
2031	180.0	210	179.1	126	23.4	0.82
2032	180.0	230	184.0	140	27.0	0.95

Table 8 - CBTS capacity limitations with Option 4 in service (EUE for "N-1" condition)

The estimated capital cost of the two capacitor banks is $3.1 million (real 2022) which has an annualised cost of $0.21 million. The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing of summer 2024-25 as shown in Figure 11.

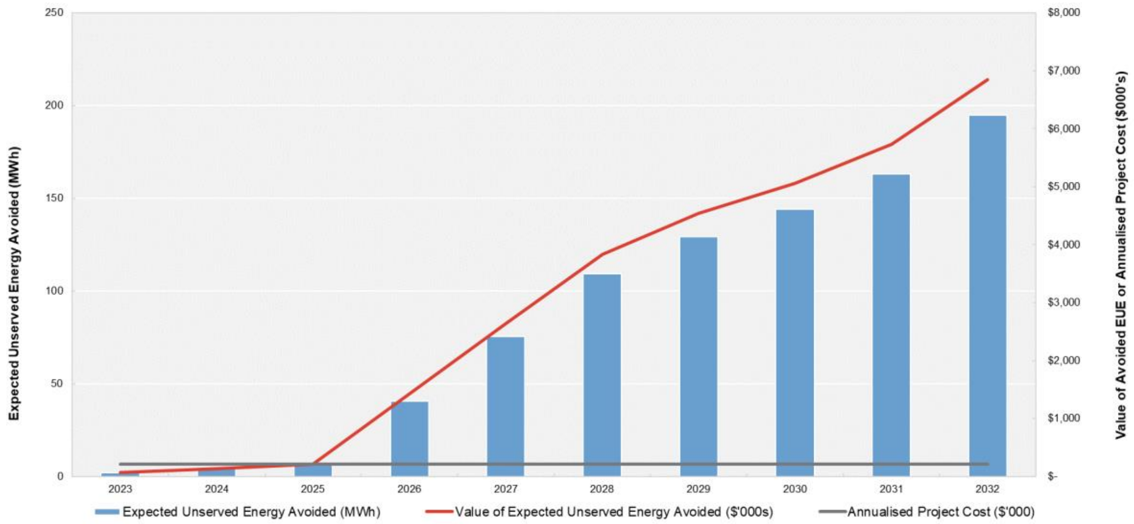

Figure 11 - Option 4 optimal timing based on avoided risks and annualised costs

Being only 14 MVA in capacity relative to the 29.9 MVA of load-at-risk by 2024-25 under the "Do nothing" option POE10 "N" condition, this option partially meets the identified need in the short-term only. This option does not meet the identified need in the longer-term because after applying this option, 34% of the supply capacity risk (i.e., the expected unserved energy) remains on CBTS by 2025-26, and 77% of the supply capacity risk remains on CBTS by 2031-32 (compared to "Do nothing").

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[22] Financial year ending 30th June.
[23] 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.

5.6. Option 5 - Establish new feeders to offload CBTS

This option involves establishing new 22 kV distribution feeders to offload CBTS in order to maintain the maximum demand on CBTS within its "N" rating and to maintain its present load transfer capability to address the identified need. There is opportunity to establish two new 22 kV distribution feeders from United Energy's Mordialloc (MC) and Frankston South (FSH) zone substations, located adjacent to the Cranbourne supply area. These zone substations, supplied by Heatherton Terminal Station (HTS) and Tyabb Terminal Station (TBTS) respectively, have spare capacity to offload parts of zone-substations CRM and LWN, which are both currently supplied from CBTS.

In total this option requires the establishment of 2.7 km of 22 kV underground cable for the new MC distribution feeder and 2.1 km of 22 kV underground cable for the new FSH feeder, as well as the zone substation works including new circuit breakers. Establishing these two feeders will allow up to 26 MVA of load to be offloaded from CBTS and could defer the preferred network option (Option 3) by two years.

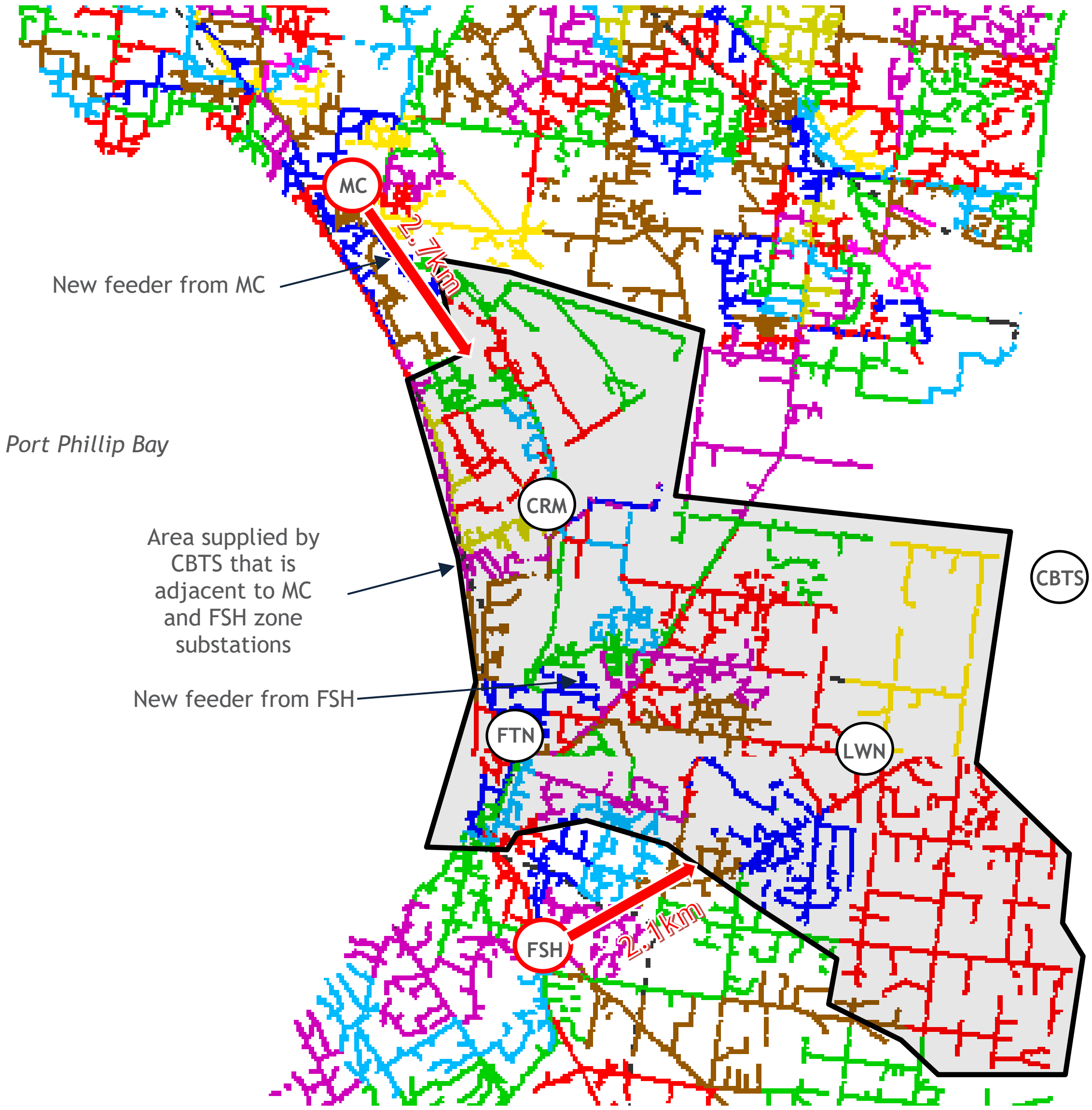

Figure 12 - Proposed new distribution feeders to offload CBTS (Option 5)

Table 9 provides a summary of the forecast "N" system normal condition capacity limitations at CBTS with Option 5 in service.

Year[24]	POE10		POE50		Probability Weighted[25]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	*6.2*	*2*	*0.0*	*0*	*0.0*	*0.00*
2024	19.0	9	0.0	0	0.0	0.00
2025	29.9	13	0.0	0	0.3	0.01
2026	43.8	18	0.0	0	14	0.50
2027	57.7	23	0.0	0	67	2.36
2028	70.5	26	0.0	0	126	4.44
2029	84.1	29	0.0	0	208	7.30
2030	97.1	32	0.0	0	301	10.6
2031	110.9	35	9.6	1	410	14.4
2032	126.7	38	23.0	2	548	19.3

Table 9 - CBTS capacity limitations with Option 5 in service (EUE for "N" condition)

Table 10 provides a summary of the forecast "N-1" contingency condition capacity limitations at CBTS (i.e., excluding the "N" system normal limitations presented above) with Option 5 in service.

Year[26]	POE10		POE50		Probability Weighted[27]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	*180.0*	*107*	*106.9*	*52*	*8.8*	*0.31*
2024	180.0	119	118.2	61	12.4	0.43
2025	180.0	130	126.9	69	16.6	0.58
2026	180.0	144	137.9	81	22.5	0.79
2027	180.0	157	149.2	93	27.1	0.95
2028	180.0	176	160.0	104	32.0	1.12
2029	180.0	196	171.6	117	36.8	1.29
2030	180.0	214	182.3	129	41.1	1.44
2031	180.0	233	184.0	141	46.0	1.62
2032	180.0	261	184.0	155	52.6	1.85

Table 10 - CBTS capacity limitations with Option 5 in service (EUE for "N-1" condition)

The estimated capital cost of the two 22 kV feeders is $3.6 million (real, 2022) which has an annualised cost of $0.23 million. The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing of summer 2025-26 as shown in Figure 13.

24 Financial year ending 30th June.
25 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.
26 Financial year ending 30th June.
27 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.

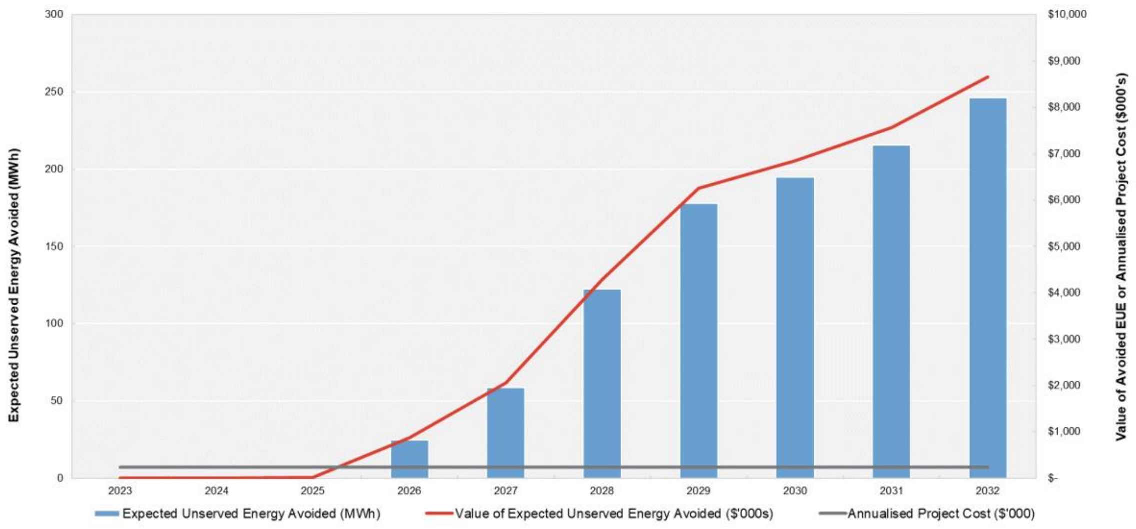

Figure 13 – Option 5 optimal timing based on avoided risks and annualised costs

Being only 26 MVA in capacity relative to the 29.9 MVA of load-at-risk by 2024-25 under the "Do nothing" option POE10 "N" condition, this option partially meets the identified need in the short-term only. This option does not meet the identified need in the longer-term because after applying this option, 60% of the supply capacity risk (i.e., the expected unserved energy) remains on CBTS by 2026, and 71% of the supply capacity risk remains on CBTS by 2032 (compared to "Do nothing").

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

This option involves establishing a new two transformer 220/66 kV terminal station in the Pakenham area (site yet to be identified) to reduce the maximum demand on CBTS, 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 zone substations PHM, CLN and LLG to the new terminal station, equating to around 170 MVA of load transferred.

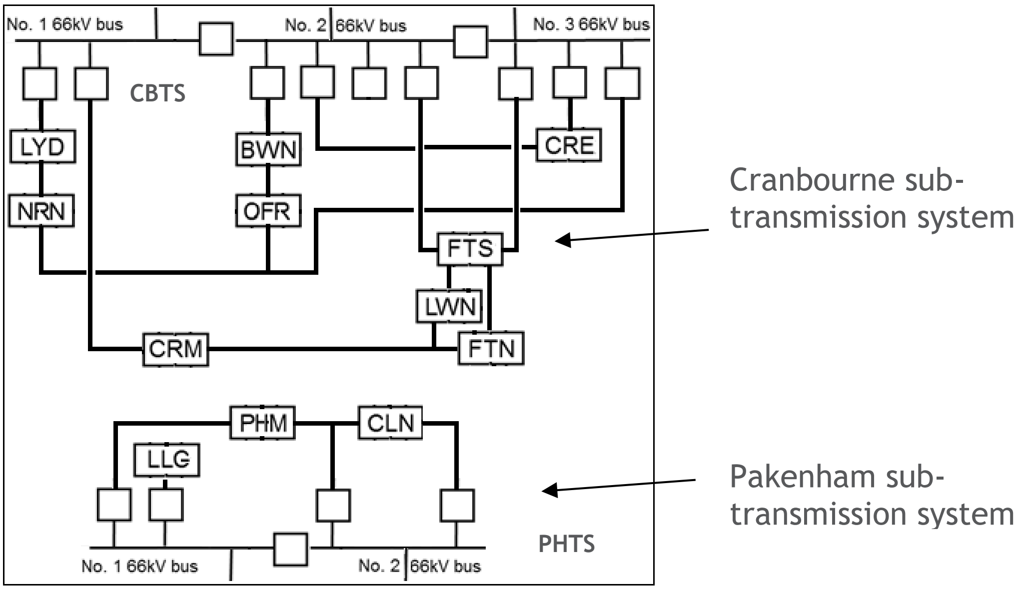

Figure 14 - Possible sub-transmission network schematic diagram (Option 6)

Table 11 summarises the forecast “N” system normal limitations at CBTS with Option 6 in service.

Year[28]	POE10		POE50		Probability Weighted[29]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	6.2	2	0.0	0	0.0	0.00
2024	19.0	9	0.0	0	0.0	0.00
2025	29.9	13	0.0	0	0.6	0.02
2026	43.8	18	0.0	0	41	1.44
2027	57.7	23	0.0	0	131	4.59
2028	0.0	0	0.0	0	0.0	0.00
2029	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00

Table 11 - CBTS capacity limitations with Option 6 in service (EUE for “N” condition)

Table 12 summarises the forecast “N-1” contingency limitations at CBTS with Option 6 in service.

[28] Financial year ending 30th June.
[29] 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.

Year[30]	POE10		POE50		Probability Weighted[31]	
	Load-at-risk (MVA)	Hours-at-risk (hr)	Load-at-risk (MVA)	Hours-at-risk (hr)	EUE (MWh)	EUE Cost ($ million)
2023	*180.0*	*107*	*106.9*	*52*	*8.8*	*0.31*
2024	*180.0*	*119*	*118.2*	*61*	*12.4*	*0.43*
2025	*180.0*	*130*	*126.9*	*69*	*16.6*	*0.58*
2026	*180.0*	*144*	*137.9*	*81*	*20.5*	*0.72*
2027	*180.0*	*157*	*149.2*	*93*	*22.1*	*0.78*
2028	0.0	0	0.0	0	0.0	0.00
2029	0.0	0	0.0	0	0.0	0.00
2030	0.0	0	0.0	0	0.0	0.00
2031	0.0	0	0.0	0	0.0	0.00
2032	0.0	0	0.0	0	0.0	0.00

Table 12 - CBTS capacity limitations with Option 6 in service (EUE for "N-1" condition)

This option meets the identified need by alleviating the supply capacity risk and removing all the expected unserved energy at CBTS over the next ten years.

This option is by far the most expensive credible option with a total estimated capital cost (including land procurement) of up to $150 million (real, 2022) which has an annualised cost of up to $10.6 million. Alternative (but less optimal) locations for a future terminal station would be at the sites reserved for the future Narre Warren or future Pearcedale North terminal stations. Whilst there would be savings on land acquisition for these two locations, this would be more than offset by the additional sub-transmission costs needed to connect in either of the two terminal stations into the supply area's electricity network. The year that the annualised cost crosses the value of the avoided EUE (realised by the network augmentation), provides an optimal timing of summer 2027-28 as shown in Figure 15.

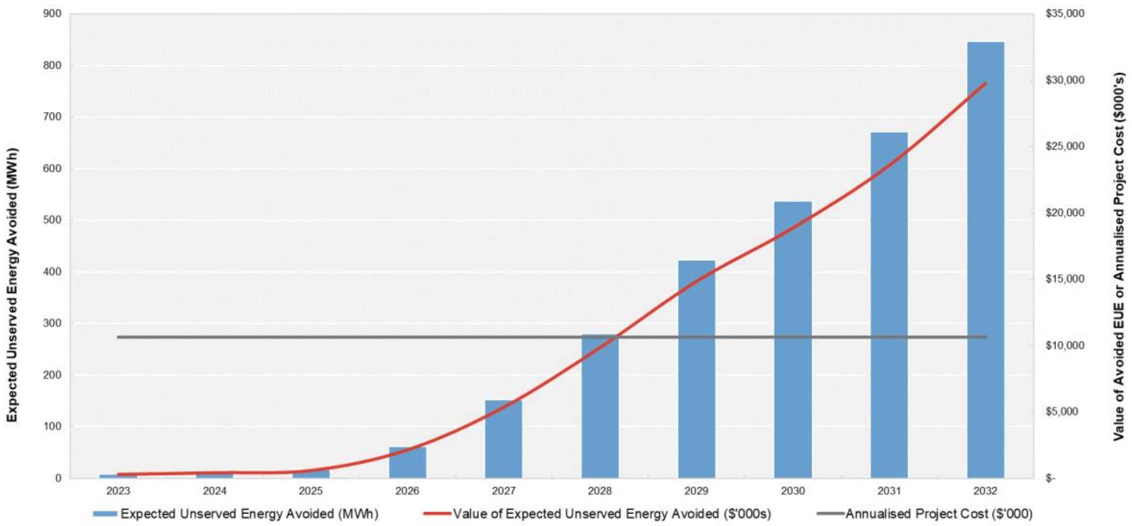

Figure 15 – Option 6 optimal timing based on avoided risks and annualised costs

[30] Financial year ending 30th June.
[31] 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.

6. Assessment approach

Consistent with the RIT-T requirements and RIT-T Application guideline, AusNet and United Energy undertook a cost-benefit analysis to evaluate and rank the net economic benefits of the credible options. All options considered have been assessed against a business-as-usual 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.

6.1. Assessment method

In planning its networks, AusNet and United Energy apply a probabilistic planning approach that balances service level risk with the cost of potential risk mitigation options to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (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.

Service level risk is monetised as the product of:

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

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

- combining the avoided service level 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 risk less the implementation and ongoing operating the 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.

6.2. Assumptions

The key assumptions used in this PADR apply to the:

- capital and operating costs of each option;
- network asset ratings;
- maximum demand growth;
- load transfer capability;

- annual load profile;
- network asset reliability (failure rates, repair times) information;
- value of customer reliability;
- discount rate; and
- assessment period (and asset life) for the economic evaluation.

Capital and operating costs

AusNet has estimated the capital costs of all options (except Options 2[32]) based on the scope of works including all transmission connections works, and associated combined sub-transmission works for both AusNet and United Energy, together with costing experience from previous projects of a similar nature. AusNet estimates that the actual cost is within ± 25 per cent of the central capital cost. An annual operating and maintenance cost of 1.0 per cent of the option's capital cost has been applied in this PADR.

Network asset ratings

The capability of the transmission connection assets at CBTS is limited by the thermal rating of its three parallel 220/66 kV 150 MVA transformers. Table 2 provides a summary of the capability of CBTS for "N" and "N-1" conditions during summer and winter (maximum demand) seasons.

Season	Existing		Post Option 3	
	"N"	"N-1"	"N"	"N-1"
Summer 35 Degrees Celsius	553	369	369 B12 369 B34	553
Summer 40 Degrees Celsius	540	360	360 B12 360 B34	540
Winter 15 Degrees Celsius	630	413	413 B12 413 B34	630

Table 13 - CBTS thermal capacity ratings (MVA)

In late-2020, AusNet Transmission Group reviewed and updated the cyclic ratings of the CBTS transformers. This review resulted in an increased "N" summer cyclic rating of 553 MVA, up from 538 MVA, and an increased "N-1" summer cyclic rating of 369 MVA, up from 356 MVA (35°C ratings). This increased cyclic rating is a result of a changing transformer load profile driven by increased rooftop PV systems, reducing terminal station loading during the day.

Maximum demand growth

The forecast maximum demand at CBTS 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[33]. Table 14 provides a summary of the forecast maximum demand for CBTS during summer and winter (maximum demand) seasons.

[32] Options 2a and 2b costs have been provided by the non-network service providers in their submission to the PSCR consultation.
[33] 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).

Year[34]	Maximum Demand Season and POE			
	Summer POE10	Winter POE10	Summer POE50	Winter POE50
2023	546	362	476	356
2024	559	366	487	360
2025	570	370	496	363
2026	584	373	507	367
2027	598	376	518	370
2028	611	381	529	374
2029	624	386	541	380
2030	637	391	551	385
2031	651	397	563	390
2032	667	402	576	395

Table 14 - CBTS forecast maximum demand (MVA)

Figure 16 shows the POE10 and the POE50 forecasts maximum demand for CBTS during summer periods relative to its capacity.

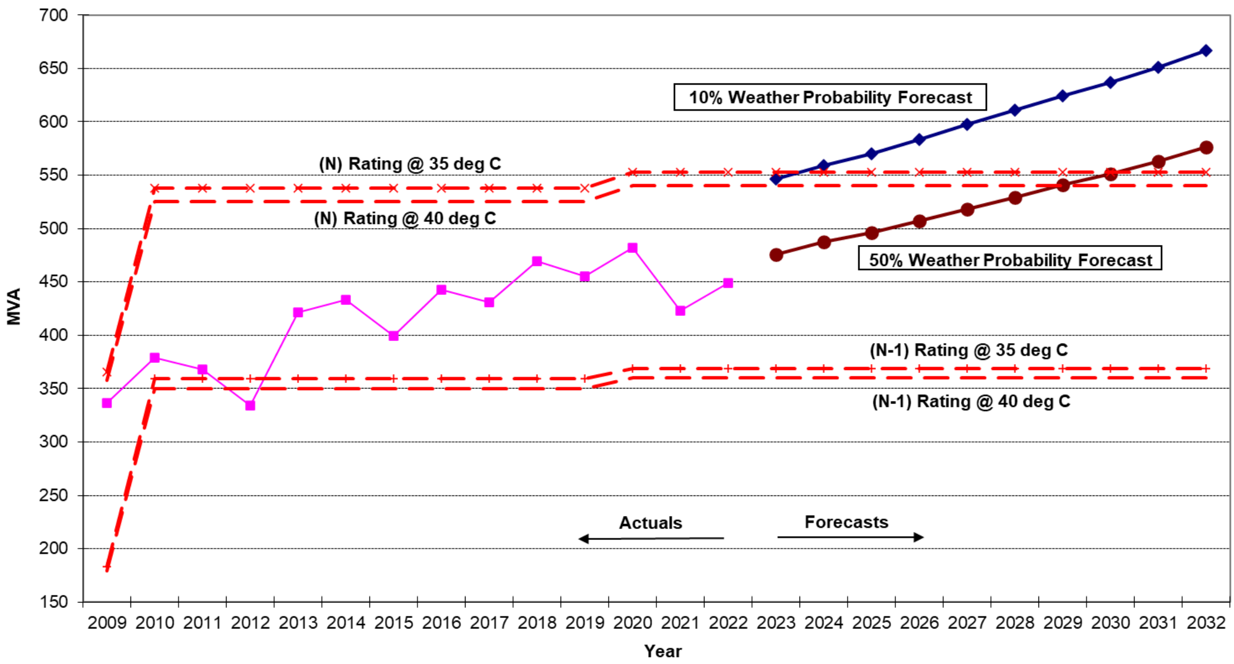

Figure 16 - Summer period maximum demand forecasts for CBTS

Figure 17 shows the POE10 and the POE50 forecast maximum demand for CBTS during winter periods relative to its capacity.

[34] Financial year ending 30th June for summer demands. Calendar year ending 31st December for winter demands.

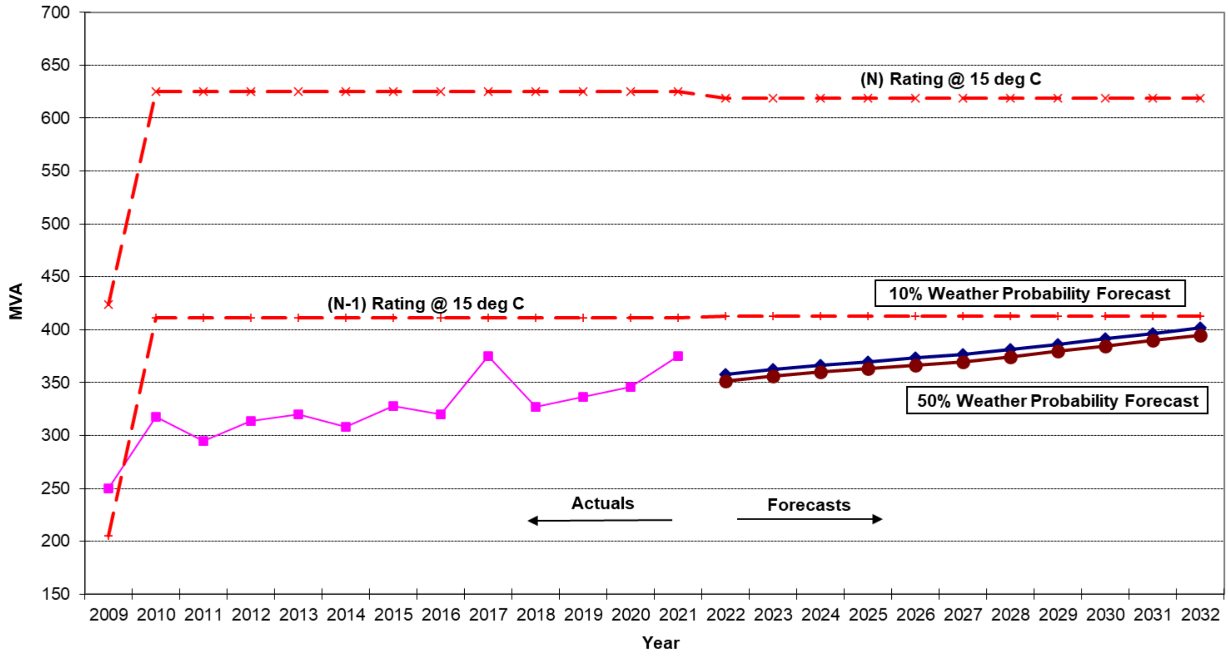

Figure 17 - Winter period maximum demand forecasts for CBTS

The maximum demand growth in the CBTS 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
- development of light industrial areas.

The demand forecasts used in this PADR were prepared in late 2021 and include the impact of the COVID-19 pandemic and recovery. AusNet and United Energy believe there remains a strong need for increased supply to meet the expected ongoing maximum demand growth at CBTS, however the results in this PADR are dependent on this forecast maximum demand being correct. To mitigate this uncertainty risk, a sensitivity analysis has been applied to the maximum demand forecast in this PADR to test the robustness of the preferred option and a scenario analysis has been undertaken, applying appropriate weightings to each growth scenario, particularly towards a possible lower maximum demand forecast.

Load transfer capability

Based the present POE10 maximum demand, there is the capacity to transfer 85 MVA of load to ERTS via the sub-transmission network without overloading ERTS. It does come with significant operational risks though because it would require AusNet to split its meshed sub-transmission network into radial lines, and would therefore only be utilised to manage the risk of an “N-1” post-contingency overload at CBTS – that is, an interruption to supply will occur before the transfer can be enacted. To manage “N” overload risk at CBTS, there is 16.8 MVA of 22kV distribution feeder transfers available on the AusNet distribution network from CBTS to ERTS.

Furthermore, there is the capacity to transfer 100 MVA of load to TBTS and 79 MVA to HTS via the sub-transmission network without overloading TBTS and HTS. Again, it does come with significant operational risks because it would require United Energy to split its meshed sub-transmission network into radial lines, and would therefore only be utilised to manage the risk of an “N-1” post-contingency overload at CBTS. To manage “N” overload risk at CBTS, there is 34.1 MVA of 22kV distribution feeder transfers available on the United Energy distribution network from CBTS – 2.2 MVA to ERTS, 9.1 MVA to HTS and 22.8 MVA to TBTS.

The total combined 22 kV distribution feeder transfer capability to manage the “N” risk in 2022-23 is forecast to be 48.7 MVA. This is limited by the peak utilisation on the adjacent distribution feeders providing the transfer capacity, and will therefore deteriorate over time as utilisation on these feeders increase.

The total combined 66 kV sub-transmission line transfer capability to manage the “N-1” post-contingency risk in 2022-23 is forecast to be 215 MVA. This is limited by the ratings of the sub-transmission lines providing the transfer capacity.

Table 15 provides a summary of the forecast load transfer capability away from CBTS to minimise EUE.

Year	Load Transfer Capability (MVA)	
	Distribution to manage “N” risk	Sub-Transmission to manage “N-1” risk[35]
2023	48.7	215
2024	41.4	215
2025	34.1	215
2026	26.8	215
2027	19.4	215
2028	12.1	215
2029	4.8	215
2030	0.0	215
2031	0.0	215
2032	0.0	215

Table 15 - CBTS available transfer capability (MVA)

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 CBTS in the following charts. Underlying load is used as the basis on which to calculate EUE for this report.

The load-duration curves for CBTS over several recent years are shown in Figure 18 for peak demand periods, and in Figure 19 for the entire year.

[35] Sub-transmission level transfers are only available for use under “N-1” post-contingency conditions due to topology limitations within the sub-transmission networks. Therefore, an outage will be experienced prior to implementing the transfers.

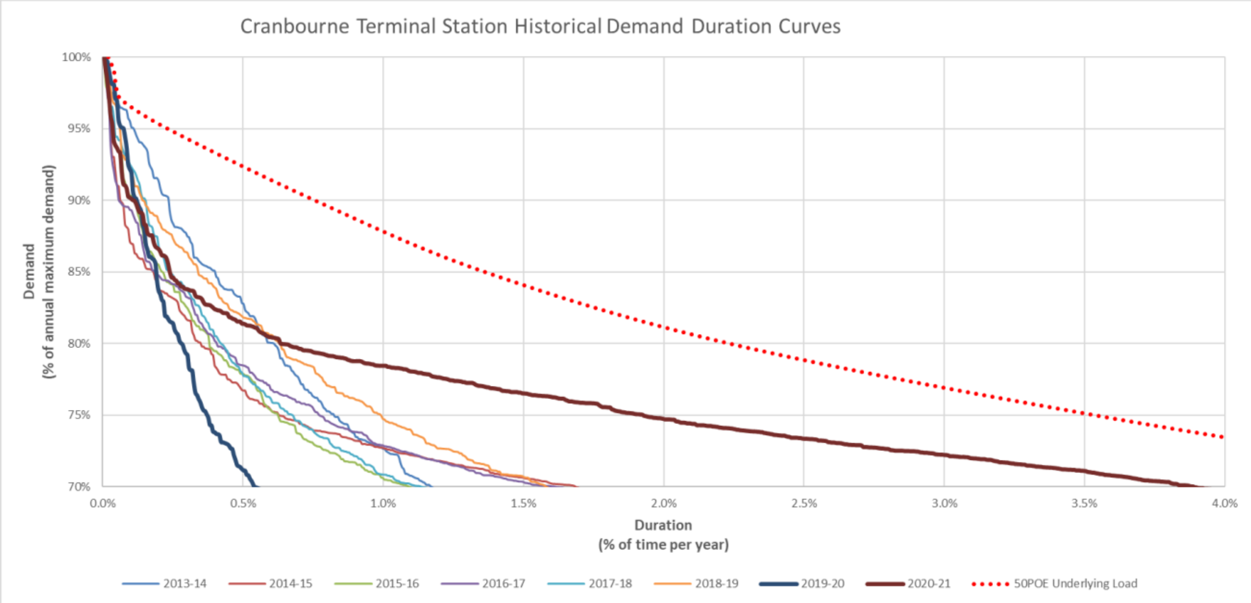

Figure 18 - Load-duration profile for CBTS - peak demand

The shape of the curves in Figure 18 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 the differences observed between the 2020-21 and 2019-20 summers.

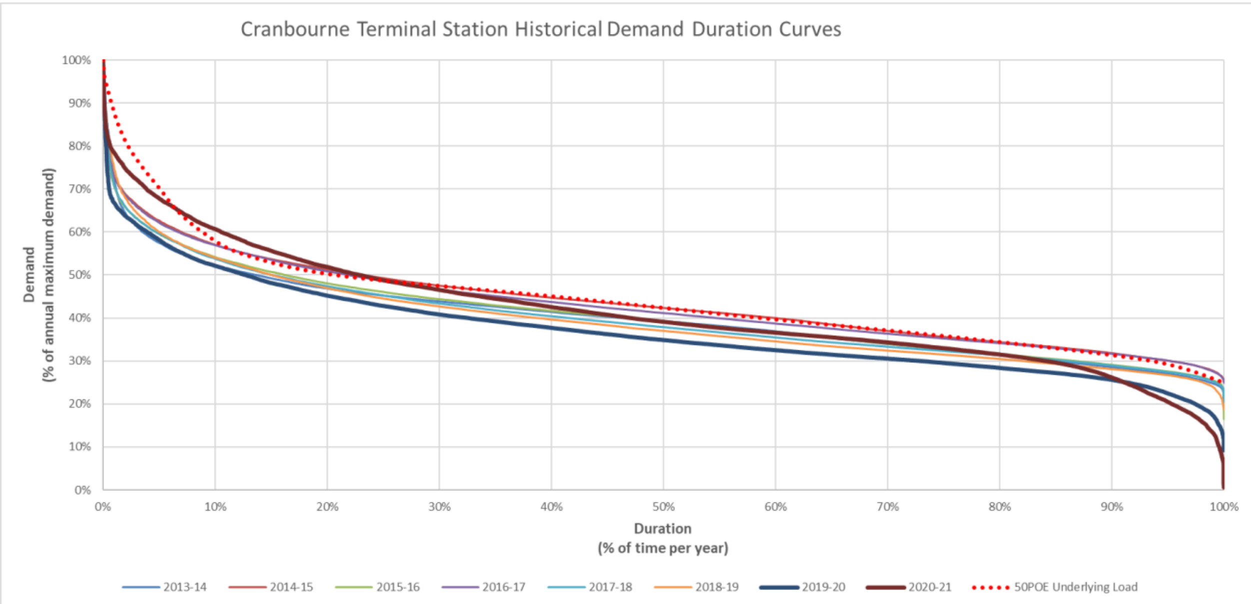

Figure 19 - Load-duration profile for CBTS - annual

The shape of the net load curves is strongly influenced by the level of distributed roof-top PV, with more recent years tapering off more rapidly (sharper peak, lower trough) compared to the more historical summers, and compared with the underlying load estimate.

Approximately 173.3 MW of rooftop solar PV is now installed on the AusNet distribution system and about 57.3 MW of rooftop solar PV is installed on the United Energy distribution system connected to CBTS. This includes all the residential and small commercial rooftop PV systems that are smaller than 1 MW.

The typical net daily load profiles at CBTS during the summer is shown in Figure 20.

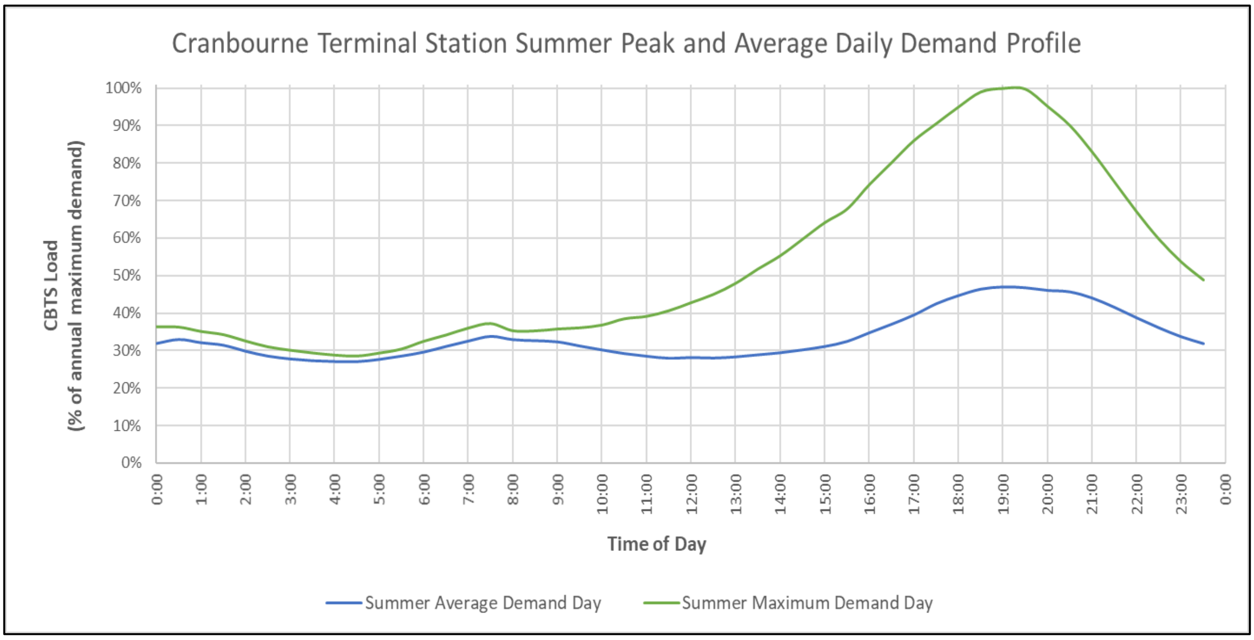

Figure 20 - Daily load profile for CBTS (summer season)

Network asset reliability

Table 16 provides a summary of the CBTS transformer reliability information used in the analysis.

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	0.217%	On average, each transformer would be expected to be unavailable due to major outages for 0.01 x 2.6/12 = 0.217% of the time, or 19 hours per year.

Table 16 - CBTS transformer reliability information

Value of customer reliability

The cost of expected unserved energy 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 United Energy have applied VCR values based on the Australian Energy Regulator's (AER) Values of Customer Reliability Review published in December 2019. Applying the AER's sector (residential, commercial, industrial and agricultural) VCRs (escalated by CPI to 2022) to terminal station level historical energy composition data from 2020-21, a CBTS VCR of $35.12/kWh was derived, as presented in Table 17.

Sector	AER VCR[36] ($/kWh)	CBTS energy consumption by sector	CBTS weighted VCR ($/kWh)
Residential	22.19 [37]	50.9%	11.31
Agricultural	39.55	2.5%	1.00
Commercial	46.49	40.7%	18.91
Industrial	66.62	5.9%	3.91
Composite		**100%**	**35.12**

Table 17 - CBTS value of customer reliability

Discount rate

It is necessary to apply a discount rate to estimate the present value of future costs and benefits and also for estimating the annualised cost of the preferred network option, which may be used as an indicative maximum annual payment that could be made available to a service provider for delivery of a non-network option to address the identified need. A real, pre-tax discount rate of 5.50 per cent has been applied as the central assumption to the cost-benefit assessments presented in this report based on a contemporary commercial discount rate.

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 20-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, assuming an asset life of 45 years. Monetised risks are capped to their year 10 values from year 11 to the end of the evaluation period.

6.3. Sensitivity studies

The robustness of the investment decision is tested using the range of input assumptions described in Table 3. This analysis varies the assumptions used for the central case as detailed in section 6.2.

Parameter	Lower Bound	Central Case	Higher Bound
Capital and Operating Costs	75% of the option's total cost	100% of the option's total cost	125% of the option's total cost
Maximum demand forecast	90% of TCPR 2021 maximum demand	100% of TCPR 2021 maximum demand	105% of TCPR 2021 maximum demand
Asset failure rate	0.8% pa	1.0% pa	1.2% pa
Value of customer reliability	80% of AER VCRs - site specific for CBTS	100% of AER VCRs - site specific for CBTS	120% of AER VCRs - site specific for CBTS
Discount rate	2.27% - the most recent WACC of a network business[38]	5.50% - the latest commercial discount	8.73% - a symmetrical adjustment upwards

[36] AER 2019 published VCRs are escalated by CPI to 2022 dollars.
[37] Climate zone 6 applies at CBTS.
[38] Real, pretax WACC from AER Final Decision for AusNet Services Transmission Determination 2022-27, January 2022, Table 3.1. https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20AusNet%20Services%20transmission%202022-27%20-%20Attachment%203%20-%20Rate%20of%20return%20-%2028%20January%202022.pdf

Parameter	Lower Bound	Central Case	Higher Bound
		rate[39]	
Asset life	20 years	45 years	60 years

Table 18 - Input assumptions used for the sensitivity studies

6.4. Material classes of market benefits

NER clause 5.16.1(c)(4) sets out the classes of market benefits that must be considered in a RIT-T. AusNet and United Energy estimate that the market benefits that are 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; and
- **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. In this RIT-T assessment, Options 2a, 2b, 4 and 5 provide option value in being able to deliver additional benefits either by mitigating risk in the lead up to, or deferring the construction of long-life assets associated with the preferred network option (Option 3). To recognise their option value potential, the optimal timing of these options has been brought forward in the economic analysis, to the extent that additional benefits can be realised. This is then followed by the implementation of the preferred network option, based on the optimal timing of the combined option.

6.5. Classes of market benefits that are not material

AusNet and United Energy 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[40].
- 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.
- changes in ancillary services costs – the options are not expected to impact on the demand for and supply of ancillary services.
- change in network losses – while changes in network losses are considered in the assessment, they are estimated to be small 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.

[39] Discount rate is based on an indicative commercial discount rate from AEMO 2021 Inputs, Assumptions and Scenarios Report, dated July 2021, Table 30. https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en

[40] Non-network option 2a of 3MW is immaterial to influence wholesale market outcomes. Option 2b of up to 150MW is likely to be able to drive wholesale market outcomes, however the proponent's proposal did not provide any detail of how their solution would generate wholesale market benefits in sufficient detail necessary for an assessment of this opportunity to be undertaken.

6.6. Scenario modelling to address uncertainty

The RIT-T analysis is required to incorporate a number of 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 as follows:

- **Central scenario -** adopting the central assumptions in Table 18;
- **Low benefits scenario** – adopting the combination of assumptions in Table 18 with relatively high uncertainty that result in the lowest benefits; and
- **High benefits scenario** – adopting the combination of assumptions in Table 18 with relatively high uncertainty that result in the highest benefits.

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 being considered. A weighting is applied to each future-state scenario to reflect the likelihood of each scenario, based on currently available information.

Parameter	Reasoning	Low Scenario	Central Scenario	High Scenario
Weighting		***40%***	***50%***	***10%***
Maximum demand forecast	Over the last decade there was significant uncertainty in forecasting maximum demand. Factors including economic growth, retail electricity prices, 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, this is likely to impact the value that customers place on supply reliability.	Lower Bound	Central Case	Higher Bound

Table 19 - Scenarios used for modelling uncertainty

The Central Scenario is regarded as the most likely since it is based primarily on a set of expected assumptions using the latest available information. A scenario weighting of 50 per cent has been applied.

The other two scenarios being weighted more pessimistically towards the Low Scenario at 40% and the High Scenario at 10%.

The rationale for applying a higher weighting towards the Low Scenario relates to uncertainty in the

High Scenario maximum demand forecast as follows:

- Maximum demand forecasts are prepared as part of the AusNet and United Energy annual planning review, and are published in December each year;
- The maximum demand forecast used in the Central Scenario of this PADR for CBTS was prepared in late 2021, published as part of the Victorian DNSPs' 2021 Transmission Connection Planning Report;
- Since the time of publishing that forecast, there have been material changes in the economic and geopolitical environment, which when assessed collectively, are more likely to have a downward pressure on maximum demand growth rather than an increase on maximum demand growth;
- Those material changes include:
    - substantially higher levels of inflation in Australia (and some others parts of the world) compared to what was expected at the time the forecasts were published;
    - the Reserve Bank of Australia (and other central banks) response to this, through the recent increases in interest rates, and the likelihood of more to come;
    - the higher possibility of negative economic growth in 2023;
    - the possibility of substantial increases in retail electricity costs for consumers as a result of the step-change increases in wholesale electricity prices in the NEM in recent months; and
    - the ongoing geopolitical and economic risks associated with Russia's invasion of Ukraine.

7. Options assessment

This chapter presents the results of the economic cost benefit analysis and the optimal timing of the preferred option.

7.1. Present value of gross 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 20 based on their central scenario optimal timing.

Option	Low Scenario	Central Scenario	High Scenario
Option 1	0	0	0
Option 2a	69.32	342.02	653.57
Option 2b	69.98	344.97	659.12
Option 3	69.30	341.92	652.84
Option 4	69.71	343.68	654.89
Option 5	69.98	342.57	648.31
Option 6	69.94	333.95	627.07

Table 20 - Calculated present value of gross benefits relative to base case ($ million, real 2022)

7.2. Present value of capital and operational 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 21 based on their based on their central scenario optimal timing.

Option	Low Scenario	Central Scenario	High Scenario
Option 1	0	0	0
Option 2a	22.55	22.56	22.57
Option 2b	29.11	29.11	29.11
Option 3	22.25	22.25	22.25
Option 4	24.12	24.12	24.12
Option 5	23.40	23.40	23.40
Option 6	134.5	134.5	134.5

Table 21 - Calculated present value of costs relative to base case ($ million, real 2022)

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 22 based on their central scenario optimal timing.

Option	Low Scenario	Central Scenario	High Scenario	Weighted	Rank
Weighting	*40%*	*50%*	*10%*	*100%*	
Option 1	0	0	0	0	7
Option 2a	46.76	319.47	631.00	241.54	2
Option 2b	40.87	315.86	630.00	237.28	5
Option 3	47.05	319.66	630.58	**241.71**	**1**
Option 4	45.58	319.55	630.77	241.09	3
Option 5	46.59	319.17	624.91	240.71	4
Option 6	(64.51)	199.50	492.62	123.21	6

Table 22 - Calculated present value of net economic benefits relative to base case ($ million, real 2022)

7.4. Preferred option

Option 3 (Install a fourth 150 MVA 220/66 kV transformer at CBTS), the preferred network option, has the highest net economic benefit relative to all other options considered, and is therefore the preferred option.

The robustness of the preferred option's net economic benefits to credible variations in key parameters (in Table 18), is demonstrated in the sensitivity study results of Figure 21.

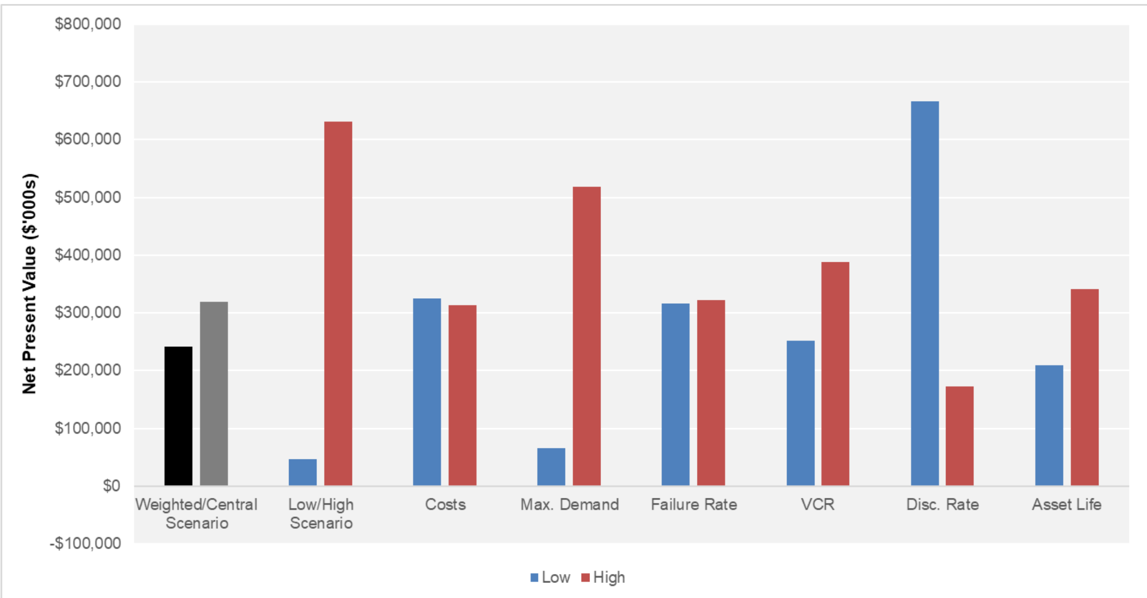

Figure 21 - NPV sensitivity analysis of the preferred option ($ thousand, real 2022)

7.5. Optimal timing of the preferred option

This section identifies and tests the robustness of the optimal timing of the preferred option for different assumptions of key parameters as detailed in Section 6.2, Table 3. The changes in timing away from the optimal timing of 2025-26 for each of the sensitivities is presented in Table 23.

Parameter	Lower Bound	Higher Bound
Capital and Operating Costs	2025-26 (no change)	2025-26 (no change)
Maximum demand forecast	2029-30 (4 years later)	2023-24 (1 year earlier)
Asset failure rate	2025-26 (no change)	2025-26 (no change)
Value of customer reliability	2025-26 (no change)	2025-26 (no change)
Discount rate	2025-26 (no change)	2026-27 (1 year later)
Asset life	2025-26 (no change)	2025-26 (no change)

Table 23 - Sensitivity of the optimal timing with respect to variation of key parameters

8. Draft conclusion and next steps

The cost-benefit assessment undertaken for this PADR confirms that Option 3 is the preferred option to meet the identified need. Option 3 is the 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 to all those who produce, consume and transport electricity in the NEM. It therefore satisfies the RIT-T.

This option involves installing a fourth 220/66 kV 150 MVA transformer at CBTS 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 fourth transformer. The scope of works would also involve installing a fourth 66kV bus, and rearrangements of the existing 66 kV sub-transmission feeders within the terminal station to allow CBTS to operate with the 66 kV bus split into a B12 and a B34 group so that maximum short circuit levels can be maintained within equipment ratings.

This preferred option is found to have positive net benefits under all scenarios investigated and on a weighted scenario basis will deliver $241.7 million in net economic benefits over its lifecycle. 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 preferred option is 2025-26 based on an estimated capital cost of $23.2 million ±25 per cent (real, 2022) with annual operating and maintenance costs relating to this investment of approximately $0.23 million. This timing is achievable based the construction lead time required for this option.

Submissions

AusNet and United Energy welcome written submissions on the issues and the credible options presented in this PADR. Submissions should be emailed to rittconsultations@ausnetservices.com.au and planning@ue.com.au on or before 8th August 2022. In the subject field, please make reference to ‘RIT-T PADR Cranbourne Terminal Station.’

Submissions will be published on the Australian Energy Market Operator (AEMO), AusNet and United Energy websites. If you do not wish for your submission to be published, please clearly stipulate this at the time of lodging your submission.

Appendix A - RIT-T assessment and consultation process

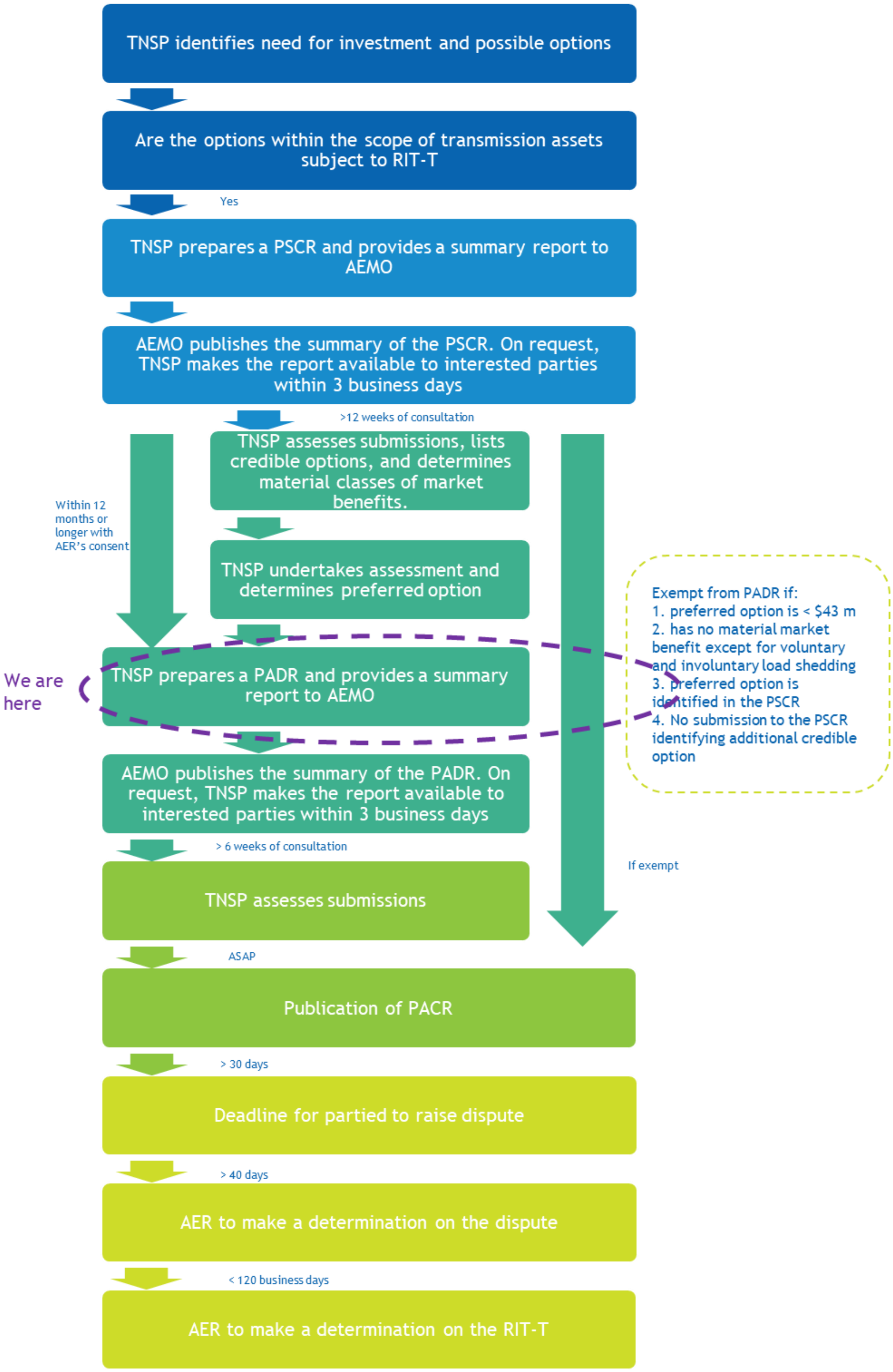

Figure 22 - RIT-T Process

Appendix B – Compliance checklist

This appendix sets out a checklist in Table 24 which demonstrates the compliance of this PADR with the requirements of Clause 5.16.4(k) of the NER.

A RIT-T proponent must prepare a report (the assessment draft report), which must include:	Chapter in this PADR
(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;	
(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 7
(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 preferred option satisfies the regulatory investment test for transmission.	Chapter 8

Table 24 – PADR compliance checklist