AEMO
AUSTRALIAN ENERGY MARKET OPERATOR
Victorian Planning

Western Metropolitan Melbourne Reinforcement

March 2025

Regulatory Investment Test for Transmission (RIT-T)

Project Specification Consultation Report (PSCR)

We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan.

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

The purpose of this publication is to, among other things, provide information about certain network limitations and potential options to address these limitations.

AEMO publishes this Project Specification Consultation Report in accordance with clause 5.16 of the National Electricity Rules (NER). This publication is generally based on information available to AEMO as at December 2024 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts, and assumptions are accurate, complete, or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results because events and circumstances frequently do not occur as expected, and those differences may be material.

This publication does not include all of the information that an investor, participant or potential participant in the national electricity market might require and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (which includes information and forecasts from third parties) should independently verify its accuracy, completeness, and suitability for purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this publication:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this publication; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person’s use of the information in this publication.

Copyright

Executive summary

AEMO Victorian Planning (AVP) is undertaking this Western Metropolitan Melbourne Reinforcement regulatory investment test for transmission (RIT-T) to assess investment options required to maintain reliable and secure supply to consumers in the western metropolitan Melbourne area (including Geelong) as demand increases and electricity supplies transition from aging coal plants which are reaching end of life and closing to new sources of supply which are mainly renewable sources. from fossil fuels to renewable sources. This Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

Demand in the western metropolitan Melbourne area is forecast to increase by 15.5% over the next 10 years. This increased demand is expected to exceed the existing network capacity, which may require operational measures such as dispatch constraints or load shedding to maintain loading within network limits unless alternative action is taken.

At the same time as this projected demand increases, the Victorian power system, like the National Electricity Market (NEM) more generally, is undergoing transformational changes with the withdrawal of several existing thermal power stations coupled with significant increases in renewable generation, battery energy storage systems (BESS) and consumer energy resources (CER).

Wind generation in the Western Victoria (V3) and South West Victoria (V4) renewable energy zones (REZs) is expected to supply an increasing proportion of electricity to the metropolitan Melbourne and surrounding areas during peak demand periods, which will in turn place increasing reliance on the transmission network west of Melbourne during these peak demand periods.

Regulatory investment test for transmission (RIT-T)

The RIT-T is an economic cost-benefit test used to assess and rank different options that address an identified need. This process establishes the business case for investment and confirms the option, ultimately paid for by consumers, that will maximise net economic benefits.

In response to expected demand increases and changes in the generation mix supplying the western metropolitan Melbourne area, AVP is undertaking this Western Metropolitan Melbourne Reinforcement RIT-T to assess options that are considered technically and economically feasible to meet the identified need. Through the assessment of credible options, the RIT-T process will identify a proposed preferred option, then ultimately a preferred option and its optimal timing.

This PSCR is the first stage of the RIT-T process, and includes:

- A description of the identified need and the assumptions used in identifying that need.
- The technical characteristics and performance requirements that a non-network option would have to deliver to meet the identified need.
- A description of all credible options which AVP is aware of that address the identified need.
- The classes of market benefits AVP considers not likely to be material (and why), along with the classes of market benefits that AVP considers likely to be material.

- An overview of the proposed assessment approach for this RIT-T.

Identified need

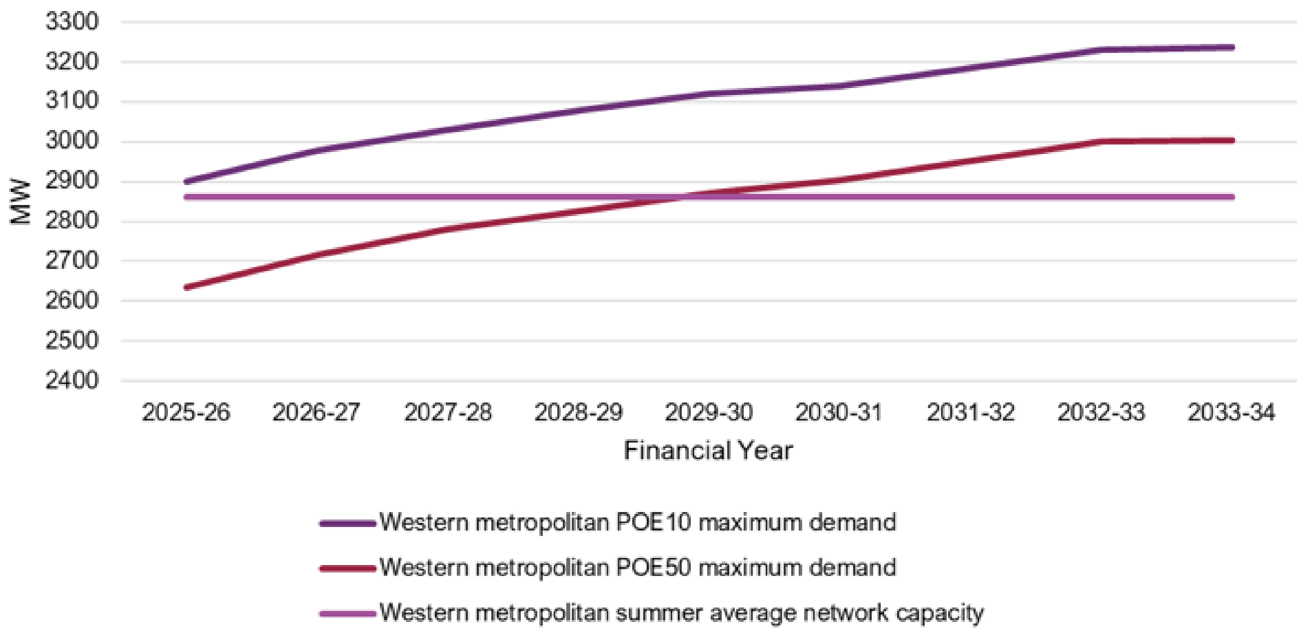
AVP has identified a need to support forecast demand growth, coupled with increasing reliance on wind generation from the V3 and V4 REZs, beyond the existing capacity of the western metropolitan Melbourne network. This is a market benefits-driven RIT-T, thereby requiring any proposed investment to deliver positive net market benefits. Market benefits for this RIT-T are primarily expected from avoided unserved energy but might also include:

- Changes in fuel costs due to the proposed investments facilitating additional generation flows on the transmission network west of Melbourne, as retiring thermal units are displaced and replaced by renewable energy resources.
- Avoided unrelated network investment.

Maximum operational electricity demand in Victoria is forecast to grow steadily over the next 10 years, including in metropolitan Melbourne. There will also be an increasing reliance on the western metropolitan Melbourne network to supply electricity to greater Melbourne during peak demand periods.

Figure 1 shows the 10% and 50% probability of exceedance (POE) demand forecast for the western metropolitan Melbourne and Geelong area compared with the approximate existing network supply capacity. Under 50% POE (one-in-two-year) demand forecasts, there is a risk that demand could exceed network capacity from summer 2029-30. The risk increases under 10% POE (one-in-10-year) demand forecasts, which show there is a risk that demand could exceed the network capacity from summer 2025-26. This highlights that there is projected to be a relatively small risk from summer 2025-26 which steadily increases over the next 10 years.

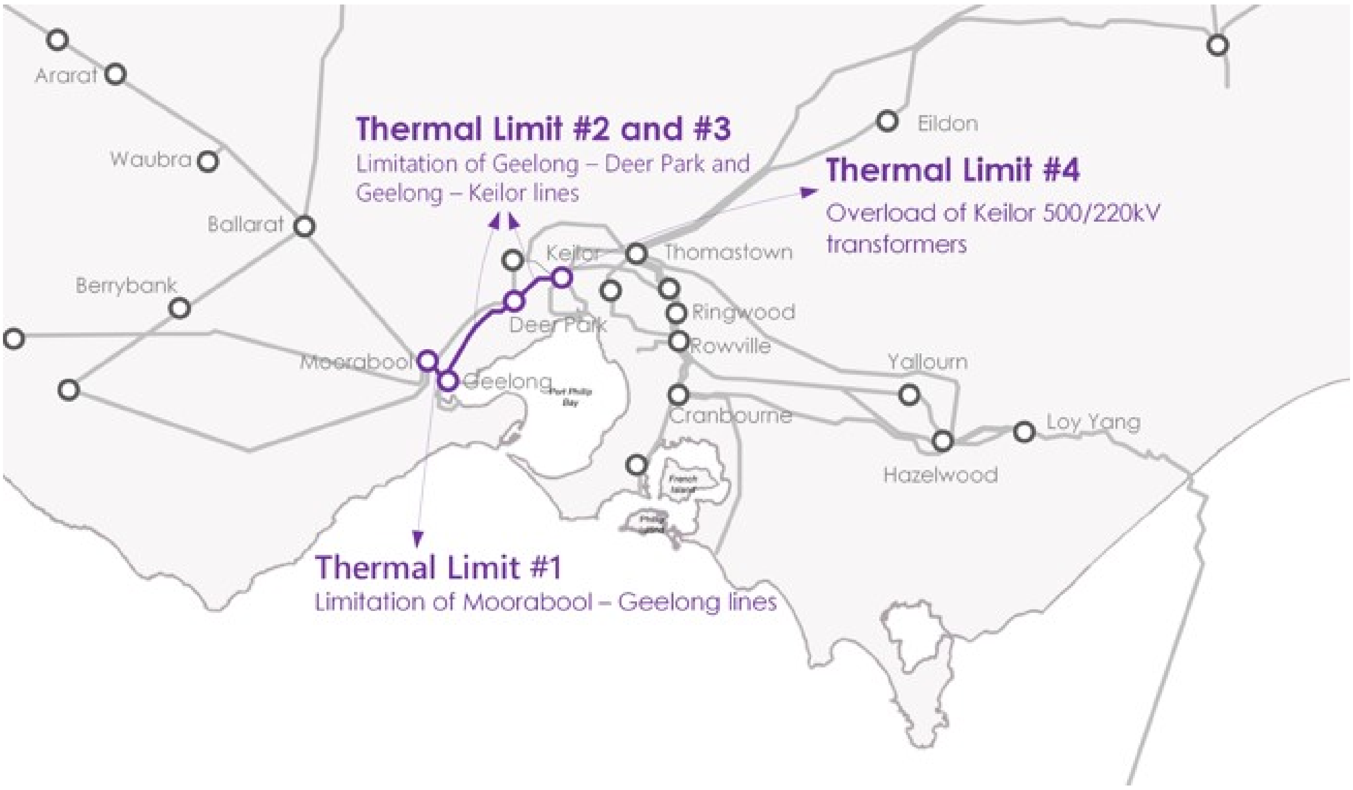
Figure 1 Western metropolitan Melbourne indicative network capacity versus maximum demand forecast, 2025-26 to 2033-34 (MW)



If no action is taken, operational measures may be required to manage network loading throughout the western metropolitan Melbourne network during peak demand periods as maximum demand in the area continues to grow.

As a result of the forecast maximum demand growth in the western metropolitan Melbourne network, coupled with expected changes in the generation mix supplying greater Melbourne, several thermal limitations have been identified under credible contingencies (with indicative timings of when each limitation is expected to arise under 10% POE peak demand conditions if no action is taken), as shown in Figure 2.

Figure 2 Thermal limitations identified under credible contingencies



The identified thermal limitations are:

- Short-term rating exceeded of the Moorabool – Geelong 220 kilovolts (kV) circuits for outage of a parallel circuit (limitation #1) – from summer 2025-26.
- Short-term rating exceeded of the Geelong – Deer Park circuit for outage of the Deer Park – Keilor circuit and similarly, short-term rating exceeded of the Deer Park – Keilor 220 kV circuit for outage of the Geelong – Deer Park circuit (limitation #2) – from summer 2025-26.
- Short-term rating exceeded of either Geelong – Keilor 220 kV circuit for outage of the parallel circuit (limitation #3) – from summer 2029-30.
- Short-term rating exceeded of the Keilor 500/220 kV transformers for outage of a parallel transformer (limitation #4) – from summer 2029-30.

If 10% POE demand forecasts eventuate, there is a risk that operational measures such as constrained dispatch, managed by AEMO's NEM Dispatch Engine (NEMDE) through binding of the existing Geelong – Moorabool 220 kV line constraints, and possibly load shedding under rare but extreme conditions, might be required from summer 2025-26. The risk increases from summer 2029-30 when network loading is forecast to exceed the rating of several network assets listed above, including under the 50% POE demand forecasts.

Credible options

Non-network options may be able to meet (or partially meet) the identified need, including:

- Demand response and decentralised storage.
- Grid-connected generators and BESS.

While AVP expects that a non-network option on its own could not fully address the identified need, it is considered possible for a non-network solution to defer the need for some of the network investment by addressing part of the identified need.

As part of the Project Assessment Draft Report (PADR), the next stage of the RIT-T process, AVP will carefully review all submissions regarding possible non-network options and assess whether combinations of network and non-network components could form credible options.

Due to the condition and age of the current Keilor 500/220 kV transformer assets, AusNet has commenced a RIT-T to investigate options to replace all three 500/220 kV transformers by 2029 to ensure safe and reliable transmission services at Keilor Terminal Station. AusNet published the PSCR in July 2024 which identifies two credible options: like for like replacement of the existing 750 megavolt amperes (MVA) transformers with modern transformers that have 150% short term rating, and replacing the 750 MVA transformers with higher capacity 1,000 MVA transformers. As a conservative assumption, AVP intends to include the like for like replacement of existing transformers (the lowest cost credible option presented in AusNet's RIT-T) as part of the base case for the analysis in this RIT-T.

In the latest Victorian Transmission Connection Planning Report (TCPR), Powercor identified an emerging network limitation at Deer Park Terminal Station and indicated that it would be assessing options to address the limitation, including via a RIT-T if necessary. This project may assist in addressing the thermal limitations associated with demand at Deer Park and is progressing separately to the investments contemplated under this RIT-T. Given the uncertainty and early stage of the project, AVP has not included any augmentations as part of the base case for the analysis in this RIT-T. However, AVP will closely work closely with Powercor as it develops its proposed investments and will respond accordingly.

AVP has identified two credible network options to address the identified need which are canvassed in this PSCR. Both options consist of several of the same augmentations, with the variation of uprating the existing Geelong – Moorabool line for Option 1 or building a new Geelong – Moorabool line for Option 2. These represent different approaches to addressing thermal limitations associated with the Moorabool – Geelong corridor.

Both options include other components necessary to address thermal limitations between Geelong, Deer Park and Keilor. Cutting the existing Geelong to Keilor circuits into Deer Park and operating the Deer Park to Keilor circuits as normally open will mean that Deer Park is supplied radially from Geelong. This avoids supply from wind generation from the west of Melbourne travelling through the Moorabool to Keilor 220 kV corridor by redirecting flows along the 500 kV network, thereby avoiding constraints on wind generation from the V3 and V4 REZs supplying greater Melbourne.

Both options also have the subcategory A and B which will assess the differential cost and benefit of replacing the 750 MVA transformers at Keilor with 1,000 MVA transformers. As discussed above the like for like replacement of existing transformers is included in the base case, therefore cost estimates for this RIT-T include no additional cost for subcategory A (like for like replacement) and only the differential costs for subcategory B (upgrading to 1000 MVA transformers).

The components of both credible options are detailed in Table 1 with indicative cost estimates (+/-50% accuracy) in real 2024 dollars. Total capital costs are expected to be $73.6 million for Option 1A, $127.5 million for Option 1B, $119.7 million for Option 2A and $173.6 million for Option 2B.

Table 1 Credible option components and capital cost estimates

Element/s of identified need	Option 1 component	Option 2 component	Cost estimate ($ million, real 2024)
Limitation #1	Uprate the Geelong - Moorabool 220 kV lines	Build a third 220 kV line between Geelong and Moorabool	7.5 for Option 1 53.6 for Option 2
Limitation #2	Cut existing Geelong to Keilor circuits into Deer Park		66.1
Limitation #1, #2 and #3	Operate Deer Park – Keilor circuits as normally open		-
Limitation #4	**Subcategory A component**		
	Like for like replacement of the three Keilor 500/220 kV 750 megavolt amperes (MVA) transformers with modern transformers that have 150% short term rating		-[A]
	Subcategory B component		
	Replace the three Keilor 500/220 kV 750 MVA transformers with 1,000 MVA transformers and perform fault mitigation works to facilitate the transformer upgrade		53.9[B]

A. The estimated capital cost of the like for like Keilor transformer replacement is $140 million. No additional cost is included for the like for like replacement of the Keilor transformers due to this cost and benefit already being included in the base case for this RIT-T.
B. The estimated capital cost of the Keilor transformer replacement with 1000 MVA transformers is $150 million. $53.9 million represents the incremental cost of upgrading to 1000 MVA transformers when the existing transformers are due for replacement in 2029 and the cost of fault mitigation works required to facilitate the transformer upgrade.

AVP estimates annual operating expenditure to be 1% of total capex for network components, for both credible options.

The options, including their costs and optimal timing, will be refined at the PADR stage based on further investigations by AVP, including in relation to:

- Any practicality issues, such as site-specific constraints.
- Submissions received to the PSCR.
- Combinations of network and non-network solutions to determine the option or hybrid option that maximises net economic benefits.
- The potential impact that a change in status of currently uncommitted connection applications for generation and storage in the western metropolitan Melbourne area may have on the identified need being addressed by this RIT-T.

- Interactions between the credible options identified in this PSCR and the credible options identified in AusNet Services' RIT-T relating to Keilor Terminal Station and in any forthcoming Powercor RIT-T regarding investment at Deer Park Terminal Station.
- Alternative strategies to mitigate fault level increases resulting from the 1,000 MVA Keilor transformer upgrade under subcategory B.

Submissions

AVP welcomes written submissions on this PSCR, particularly from potential proponents of non-network options. All feedback will be considered and will help refine the proposed preferred option to be published in the PADR.

Submissions should be emailed to AVP_RIT-T@aemo.com.au with subject title 'Western Metropolitan Melbourne Reinforcement PSCR' and are due on or before 5.00 pm on 6th June 2025.

At the conclusion of the consultation process, all non-confidential submissions received will be published on AEMO's website. If you do not wish for your submission to be made public, please clearly stipulate this at the time of lodgement.

Next steps

Following consultation on this PSCR, the next stage of the RIT-T process, in accordance with the requirements of National Electricity Rules (NER) 5.16.4, is a full options analysis and publication of the PADR.

Contents

Tables

Figures

1 Introduction

AEMO Victorian Planning (AVP) is undertaking this Western Metropolitan Melbourne Reinforcement regulatory investment test for transmission (RIT-T) to assess investment options required to maintain reliable and secure supply to consumers connected to the western metropolitan Melbourne network as demand increases and electricity supplies transition from aging coal plants which are reaching end of life and closing to new sources of supply which are mainly renewable sources.

Demand in the western metropolitan Melbourne area is forecast to increase by 15.5% over the next 10 years[1]. This increased demand is expected to exceed the existing network capacity, which may require operational measures such as dispatch constraints or load shedding to maintain loading within network limits unless alternative action is taken.

AVP has prepared this Project Specification Consultation Report (PSCR) in accordance with the requirements of National Electricity Rules (NER) 5.16.4 for a RIT-T. It represents the first step in the RIT-T process.

In line with NER requirements, this PSCR provides:

- A description of the identified need and the assumptions used in identifying that identified need.
- The technical characteristics and performance requirements that a non-network option would have to deliver to meet the identified need.
- A description of credible options considered by AVP to address the identified need including, for each credible option:
  - Technical characteristics.
  - Estimated construction timeline and commissioning date.
  - Indicative capital, operating and maintenance costs.
  - Whether the option is reasonably likely to have a material inter-network impact.
- The classes of market benefits AVP considers not likely to be material (and why), along with the classes of market benefits that AVP considers likely to be material.

An overview of the proposed assessment approach for this RIT-T has also been included to encourage early engagement.

The next stage of the RIT-T process is the publication of a Project Assessment Draft Report (PADR). The PADR will address submissions received on this PSCR.

[1] This is based on 10% probability of exceedance (POE) forecast demand growth from 2025-26 to 2033-34. The assumptions behind these forecasts and the sites included in the western metropolitan Melbourne area are set out in Section 2.3.1.

2 Identified need

Forecast demand growth driven by urban sprawl and increasing electrification of various industries, coupled with changing power flow patterns as thermal generators retire and are displaced and replaced by renewable energy sources and new interconnectors, is expected to result in future loading that exceeds the existing western metropolitan Melbourne network thermal capacity.

To maintain secure supply under these changing power system conditions, AVP has identified a need to invest and is undertaking this benefits-driven RIT-T to identify the option that maximises net economic benefits. These net economic benefits will flow on to provide benefits for NEM energy consumers.

2.1 Background

Demand growth and changes to the generation mix in Victoria are the two key drivers of the identified need for this RIT-T.

Demand growth

Maximum demand in the western metropolitan Melbourne area (including Geelong) is forecast to grow at an average annual growth rate of 2.7% over the next three years and 1.6% over the next 10 years[2]. This demand growth is driven by increasing electrification of various industries coupled with high population growth and increasing commercial and industrial customer connections.

Additionally, forecast maximum demand periods continue to occur in the early evening outside sunlight hours in Victoria, minimising the ability of distributed photovoltaic (PV) systems to dampen transmission network maximum demand growth, relative to other fundamental drivers of growth such as new connections or appliance uptake[3].

While demand growth across the entire western metropolitan Melbourne network is a key driver of the identified need for this RIT-T, AVP notes that strong growth expected at particular locations within the western metropolitan network also drives the need for investment. Local demand growth at Deer Park contributes to the identified need (discussed below) – maximum demand at Deer Park Terminal Station is forecast to grow at an average annual growth rate of 3.8% over the next three years and 2.8% over the next 10 years.

Changing generation mix

The Victorian power system, like the NEM more generally, is undergoing transformational changes with the projected withdrawal of several existing thermal power stations coupled with significant increases in renewable generation, battery energy storage systems (BESS) and consumer energy resources (CER).

[2] The assumptions behind these forecasts and the sites included in the western metropolitan Melbourne area are in Section 2.3.1.

[3] See Section 2.1 of AEMO's 2024 *Electricity Statement of Opportunities* (ESOO), at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf?la=en&hash=2B6B6AB803D0C5F626A90CF0D60F6374.

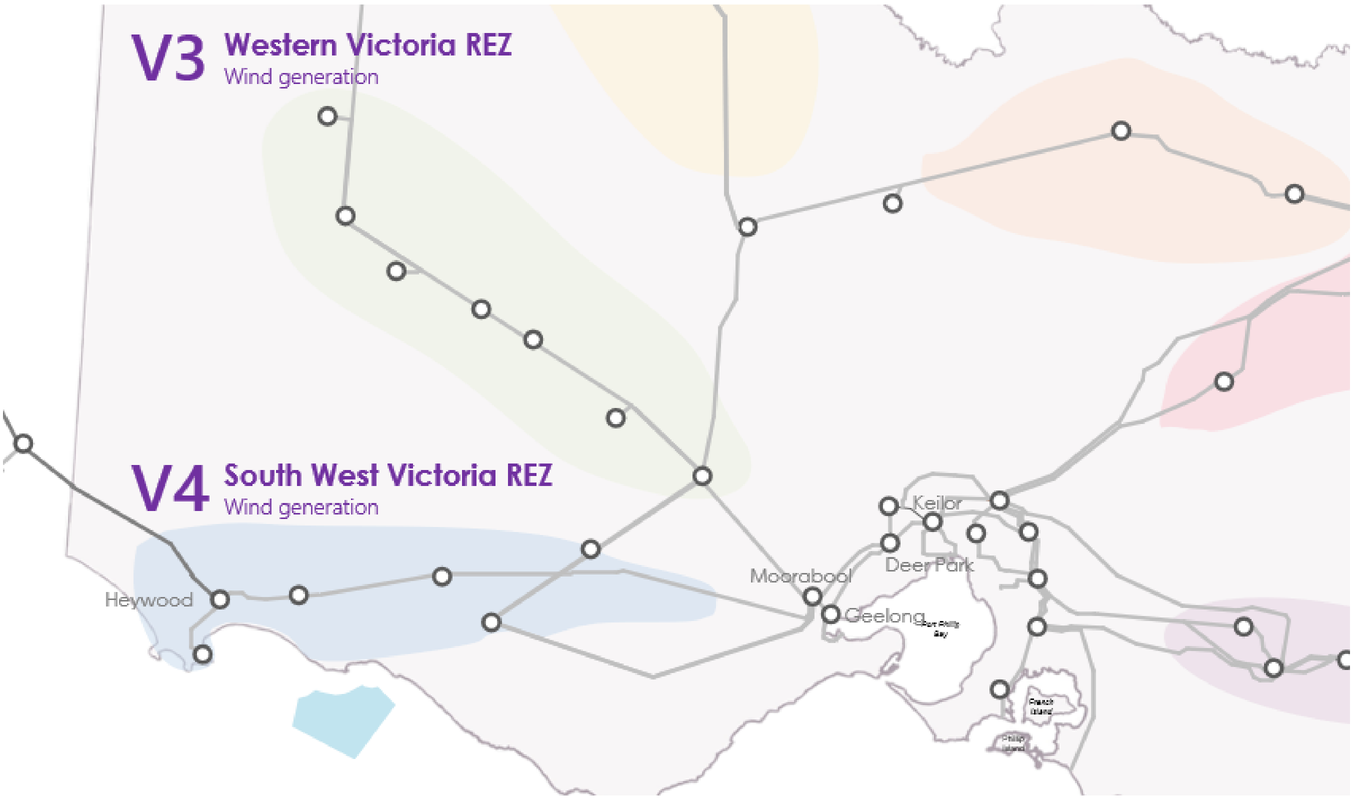
Wind generation in the Western Victoria (V3) and South West Victoria (V4) Renewable Energy Zones (REZs) is expected to supply an increasing proportion of electricity to greater Melbourne during peak demand periods. Capacity from existing, committed and anticipated wind generation from these two REZs exceeds 5.2 gigawatts (GW), with wind generation capacity in both REZs projected to grow to 7.5 GW by 2033-34[4]. This will in turn place increasing reliance on the transmission network west of Melbourne to supply electricity to greater Melbourne during peak demand periods.

Related developments

AVP's 2023 *Victorian Annual Planning Report* (VAPR)[5] highlighted that, at times of high demand in the western metropolitan area and high wind generation in and around the V3 and V4 REZs, the 220 kV transmission corridor between Moorabool, Geelong, Deer Park, and Keilor is becoming constrained and is anticipated to become heavily constrained over the coming decade.

Figure 3 shows the approximate locations of the V3 Western Victoria and V4 South West Victoria REZs and the locations of four key terminal stations in the western metropolitan Melbourne 220 kV network: Moorabool Terminal Station, Geelong Terminal Station, Deer Park Terminal Station, and Keilor Terminal Station.

Figure 3 Location of wind generation and Moorabool, Geelong, Deer Park and Keilor terminal stations



[4] AEMO, 2024 *Integrated System Plan* (ISP), Appendix 3: Renewable Energy Zones, June 2024, pp 90-93, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

[5] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

The **Western Renewables Link (WRL)** is expected to assist in alleviating constraints in this 220 kV corridor by creating a new, separate 500 kV path (Bulgana to Sydenham) for wind generation to supply load to the western metropolitan Melbourne area. This project is in delivery stage and planned to be completed in mid-2027[6].

However, shortly after the construction of WRL, the **retirement of Yallourn W Power Station (YWPS)** is expected to further increase reliance on generation from the V3 and V4 REZs during peak demand. YWPS, located in the Latrobe Valley in eastern Victoria, is scheduled to retire by mid-2028. While YWPS remains in service it will continue to provide a source of dispatchable generation from Latrobe Valley to greater Melbourne. Following its retirement, this supply will need to be replaced by other generation sources across the Victorian network. This will increase the reliance on wind generation from V3 and V4 REZs during peak demand periods when generation reserves are low, exacerbating the thermal limitations identified above.

In the latest Victorian Transmission Connection Planning Report (TCPR), Powercor identified an emerging **network limitation at Deer Park Terminal Station** and indicated that it would be assessing options to address the limitation, including via a RIT-T if necessary[7]. This project may assist in addressing the thermal limitations associated with demand at Deer Park and is progressing separately to the investments contemplated under this RIT-T. Given the uncertainty and early stage of the project, AVP has not included any augmentations as part of the base case for the analysis in this RIT-T. However, AVP will closely work closely with Powercor as it develops its proposed investments and will respond accordingly.

AVP's recently published **Metropolitan Melbourne Voltage Management RIT-T** identified a preferred option that includes installation of a 100 megavolt amperes reactive (MVAr) shunt capacitor bank on the 220 kV level at Deer Park Terminal Station by 2030-31[8]. There is a prospect that the investments contemplated in this RIT-T could avoid the need for the shunt capacitor at Deer Park. This is discussed further in Section 4.

AusNet has commenced a RIT-T to investigate **options to ensure safe and reliable transmission services at Keilor Terminal Station.** AusNet's RIT-T notes that the condition and age of current assets presents a safety, supply, environmental and collateral damage risk in the event of an asset failure. AusNet is therefore planning to replace all three 500/220 kV transformers at Keilor Terminal Station by 2029. The PSCR presents two credible options: like for like replacement of the existing 750 megavolt amperes (MVA) transformers with modern transformers that have 150% short term rating, and replacing the 750 MVA transformers with higher capacity 1,000 MVA transformers. As a conservative assumption, AVP intends to include the like for like replacement of existing transformers (the lowest cost credible option) as part of the base case for the analysis in this RIT-T, such that any additional costs that would need to be incurred above the like for like replacement are included in the cost estimate for this RIT-T.

The **Western Victoria Grid Reinforcement future *Integrated System Plan* (ISP) project** is a separate project that will focus on options for increasing the capacity of the 500 kV network linking key load centres with the V4 South West Victoria REZ[9]. Although some credible options, such as augmenting the Moorabool to Geelong

---

[6] AEMO, 2024 VAPR, October 2024, p 5.

[7] Victorian distribution network service providers (DNSPs), *2024 Transmission Connection Planning Report*, pp 5 and 92, at https://dapr.ausnetservices.com.au/ausnet_data/2024%20TCPR.pdf.

[8] AVP, *Melbourne Metropolitan Voltage Management – Project Assessment Draft Report*, July 2024, at https://www.aemo.com.au/initiatives/major-programs/metropolitan-melbourne-voltage-management-regulatory-investment-test-for-transmission.

[9] AEMO, 2024 ISP, p 64.

capacity, may be considered under both, the Western Victoria Grid Reinforcement future ISP project will be subject to a separate process in future and is not expected to affect the augmentations considered here.

2.2 Description of the identified need

AVP has identified a need to support forecast demand growth beyond the existing capacity of the western metropolitan Melbourne network coupled with increasing reliance on wind generation from the V3 and V4 REZs. This is a market benefits-driven RIT-T, thereby requiring any proposed investment to deliver positive net market benefits. Market benefits are primarily expected from avoided unserved energy but may also include:

- Changes in fuel costs due to the proposed investments facilitating additional generation flows on the transmission network west of Melbourne, as retiring thermal units are replaced with renewable resources.
- Avoided unrelated network investment.

These categories of market benefit are discussed further in Section 4.

Maximum operational electricity demand in Victoria is forecast to grow steadily over the next 10 years[10], including in metropolitan Melbourne[11]. Meanwhile, there will be an increasing reliance on the western metropolitan Melbourne network to supply electricity to greater Melbourne during peak demand periods.

The western metropolitan Melbourne network is currently capable of supplying approximately 2,860 megawatts (MW) of demand during average summer peak temperatures (35°C). Most transmission lines in the western metropolitan Melbourne network have dynamic temperature ratings which allow for higher ratings at lower ambient temperatures and lower ratings at higher ambient temperatures. As a result, the network limit falls steadily as the temperature rises, and reaches approximately 2,700 MW during summer high temperature conditions[12].

There is a risk that demand will exceed the average summer peak capacity of the western metropolitan Melbourne network from summer 2029-30 under 50% probability of exceedance (POE) demand forecasts (one-in-two-year). Under 10% POE demand forecasts (one-in-10-year), the risk is present earlier – from summer 2025-26 and gradually increases over the next 10 years. If no action is taken, then operational measures may be required to manage network loading throughout the western metropolitan Melbourne network during peak demand periods as maximum demand in the area continues to grow.

Figure 4 shows the 10% and 50% POE demand forecast for the western metropolitan Melbourne area[13] compared with the approximate existing network supply capacity during summer peak demand conditions. This figure highlights that there is a relatively small risk from summer 2025-26 which steadily increases over the next 10 years.

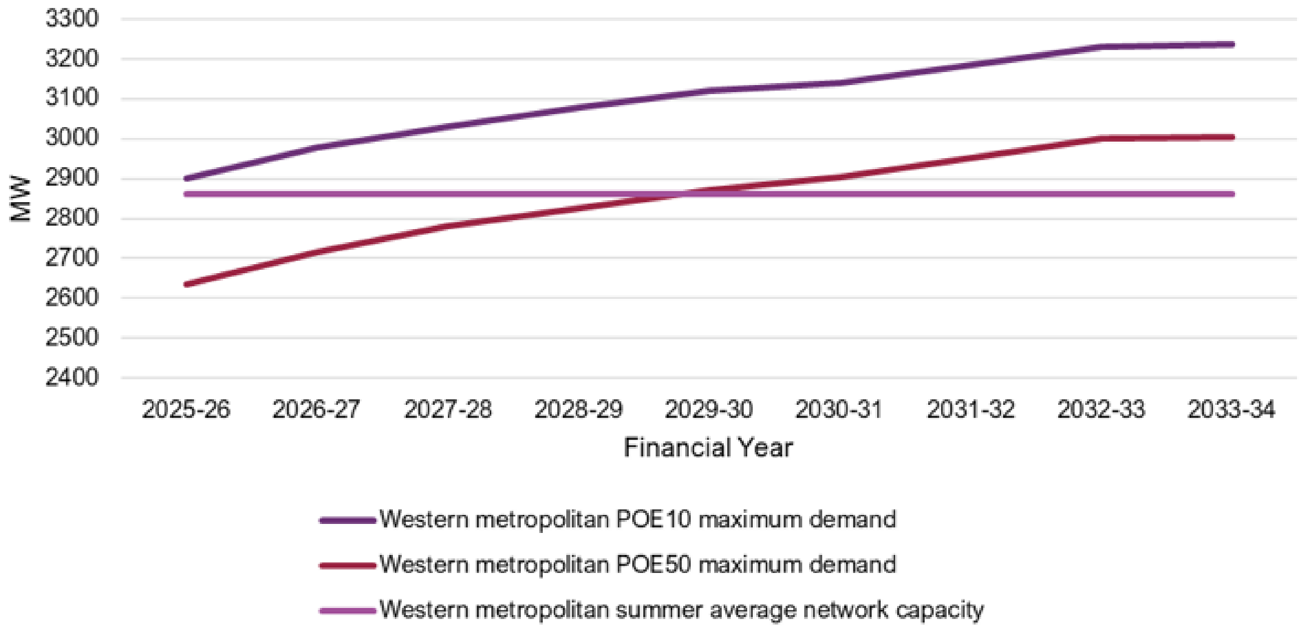
[10] AEMO, 2024 ESOO, August 2024, pp 158-159. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[11] AEMO, 2024 *Victorian Connection Point Demand Forecast*, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

[12] Summer high temperature conditions assume 45°C equipment ratings which reduces the network supply capacity. This temperature has been included as a worst case scenario because high temperatures are a driver of high demand in summer and peak demand days typical coincide with high ambient temperatures.

[13] The assumptions behind these forecasts and the sites included in the western Melbourne area are in Section 2.3.1.

Figure 4 Western metropolitan Melbourne approximate network capacity versus maximum demand forecast, 2025-26 to 2033-34 (MW)[14]



Due to the forecast maximum demand growth in the western metropolitan Melbourne network, coupled with expected changes in the generation mix supplying greater Melbourne, several emerging thermal limitations have been identified. AVP is proposing to address these limitations through investment under this RIT-T. Addressing these limitations will increase the supply capacity of the western metropolitan Melbourne network in peak demand conditions and ensure reliable and secure supply to consumers.

In the 2023 VAPR, AVP identified three network limitations associated with the generation and demand developments outlined above[15]:

- Short-term rating exceeded of the Moorabool – Geelong 220 kV lines for trip of the parallel line (limitation #1).
- Short-term rating exceeded of the Geelong – Deer Park line for trip of the Deer Park – Keilor line, or the Deer Park – Keilor 220 kV line for trip of the Geelong – Deer Park line[16] (limitation #2).
- Short-term rating exceeded of the Geelong – Keilor 220 kV lines post credible contingencies (limitation #3).

AVP's 2024 VAPR explains that this Western Metropolitan Reinforcement RIT-T has been commenced to provide a solution that addresses each of these limitations, categorising each of them as priority limitations[17].

AVP has identified a further limitation within the western metropolitan network in preparing this PSCR:

- Short-term rating exceeded of the 500/220 kV transformers at Keilor post credible contingencies (limitation #4).

[14] The assumptions behind these forecasts and the sites included in the western Melbourne area are set out in Section 2.3.1

[15] See pp 61, 68.

[16] The thermal limitation of the Geelong - Deer Park – Keilor lines will remain regardless of investments directed at voltage control at Deer Park due to the forecast increase in demand at Deer Park.

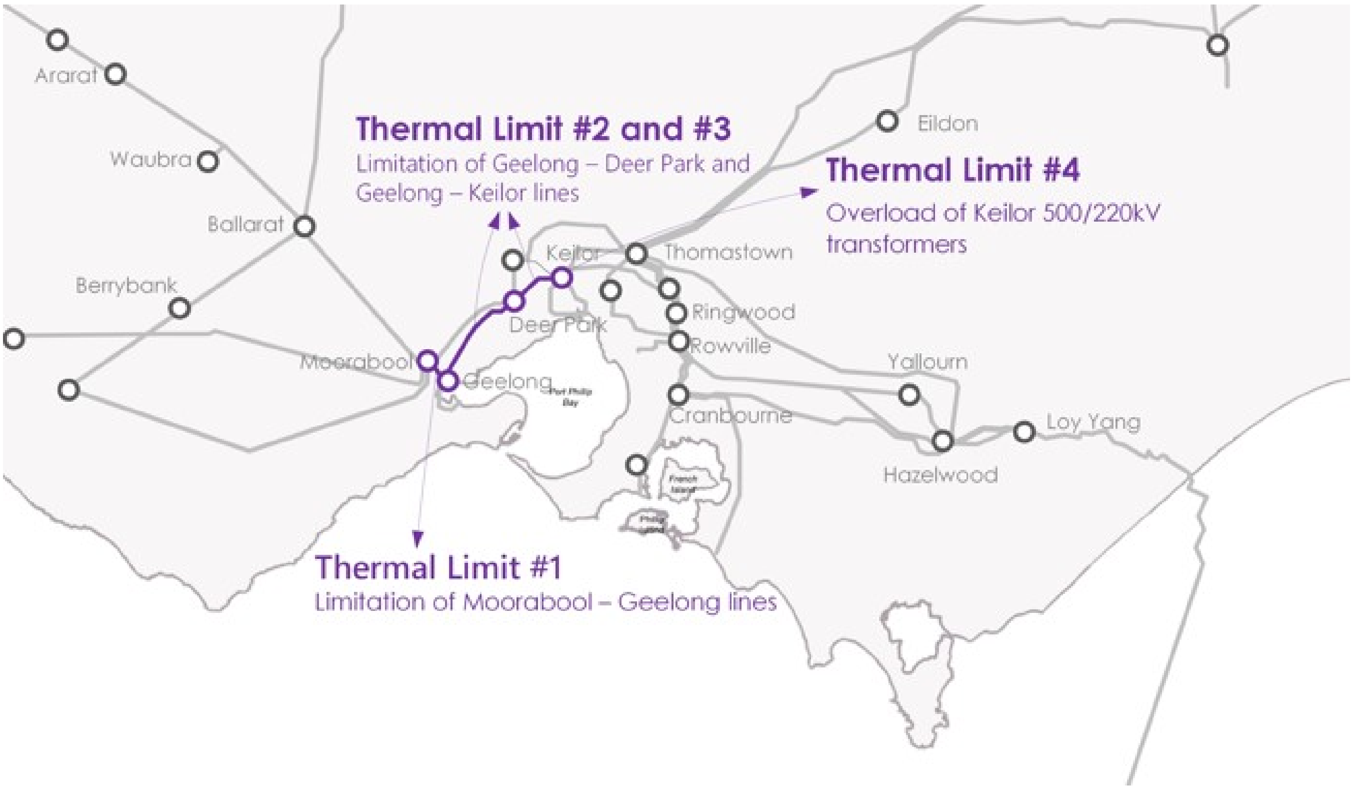
[17] See pp 60, 65.

The indicative timings for when each of these limitations first bind in the base case are set out below (this assumes 10% POE peak demand conditions):

- Moorabool – Geelong 220 kV line loading is forecast to exceed its N-1 short-term rating following the contingent loss of the other Moorabool – Geelong 220 kV line in summer 2025-26.
- Following contingent loss of the Geelong – Keilor 220 kV line:
  - The other Geelong – Keilor 220 kV line loading is forecast to exceed its N-1 short-term rating in summer 2029-30.
  - The Geelong – Deer Park 220 kV line loading is forecast to exceed its N-1 short-term rating in summer 2029-30.
- Following contingent loss of the Geelong – Deer Park 220 kV line or Deer Park – Keilor 220 kV line, the remaining Geelong – Deer Park 220 kV line or Deer Park – Keilor 220 kV line is forecast to exceed its N-1 short-term rating in summer 2025-26.
- Geelong – Deer Park 220 kV line loading is forecast to exceed its system normal (N) continuous rating in summer 2028-29.
- Following contingent loss of the Keilor 500/220 kV A4 or A2 transformer the remaining A4 or A2 transformer is forecast to exceed its N-1 short-term rating in summer 2029-30.

Figure 5 below shows the location of key network assets and related thermal limitations impacting supply capability to the greater western metropolitan Melbourne area.

Figure 5 Network assets and related thermal limitations impacting western metropolitan Melbourne supply



Estimates of the extent of involuntary load curtailment that would be required to maintain loading within network limits under the base case are set out in Section 4.

In addressing the limitations identified above, this RIT-T has two key aims:

- Reducing the cost of expected unserved energy (EUSE) that would otherwise be required to maintain network loading within the thermal rating of existing assets in the western metropolitan Melbourne area.
- Enabling greater transfer capacity between the V3 and V4 REZs, key load centres within the greater western metropolitan network (such as Geelong and Deer Park), and western metropolitan Melbourne. Transfer capacity from the V3 and V4 REZs is expected to be constrained during summer high demand periods in the future if no action is taken.

2.3 Assumptions used in identifying the identified need

This section sets out the assumptions underpinning the identified need, including:

- Demand forecasts.
- Generation and dispatch forecasts.

2.3.1 Demand forecasts

AVP performed studies using the models developed for the 2024 VAPR to estimate the level of unserved energy required to maintain loading within network limits. The studies incorporate a regional demand that reflects the latest forecasts set out in the 2024 *Electricity Statement of Opportunities* (ESOO).

AVP applied a 45°C ambient temperature rating to all equipment in the model when identifying emerging network limitations. Summer peak demand conditions assumed 45°C equipment ratings, which reduces the network supply capacity. This assumption was made because high temperatures are a driver of high demand in summer and peak demand days typically coincide with high ambient temperatures.

In calculating EUSE, AVP performed load flow studies to determine the western metropolitan Melbourne network capacity over a range of temperatures, then carried out analysis using historical temperature recordings and metered data scaled to align with AEMO connection point forecasts to determine EUSE.

As there is significant interconnection between the terminal stations in the western metropolitan Melbourne network, AVP calculated the risk across the entire area, which includes terminal stations located at West Melbourne, Fishermans Bend, Brooklyn, Altona, Deer Park, Geelong and Keilor.

Due to a low risk of EUSE in the western metropolitan Melbourne network under 90% POE demand conditions, AVP only performed studies for 10% POE and 50% POE demand forecasts. The 10% POE and 50% POE outcomes were weighted consistent with the *ESOO and Reliability Forecast Methodology* at 30.4% and 39.2% respectively, with zero EUSE assumed for the remaining 30.4% weighting assigned to 90% POE[18]. See Section 5.6 for more details on the EUSE weighting.

[18] See Section 5.2.2 at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

AVP expects to receive updated connection point forecasts in Q1 2025, and intends to use these for the PADR assessment.

2.3.2 Generation and dispatch assumptions

Studies performed by AVP to identify the need for investment covered by this PSCR considered the following publications for the development of power system models which align with those used for the 2024 VAPR[19]:

- Offshore wind targets based on AEMO's 2023 *Inputs, Assumptions and Scenarios Report* (IASR)[20].
- All committed, anticipated, and actionable ISP projects impacting the Victorian region from the July 2024 update on AEMO's NEM Transmission Augmentation Information web page[21].
- Generation plant and retirement information based on the July 2024 update on AEMO's Generation Information web page[22].

Table 2 summarises the dispatch assumptions for the power system studies which align with those used for the maximum demand scenario modelled as part of the 2024 VAPR studies.

Table 2 Dispatch assumptions for maximum demand base case

Generation type	Dispatch assumption for maximum demand scenario
Grid-scale solar	Up to 23.2% for years 1-5 and up to 15.3% for years 5-10
Wind farms	Up to 21.2% for years 1-5 and up to 50% for years 5-10[A]
BESS	Online with output at 50% capacity
Synchronous generation (coal, gas, and hydro)	Online with output up to maximum rated capacity
Interconnectors	The inter-regional flows are set to be consistent with the FY2023-24 historical year with a demand level close to 10% POE conditions and adjusted if necessary to accommodate the recent changes in operating conditions (such as any change in interconnector limits, demand and generation)[B]

A. Studies performed from year 5-10 assumed above average capacity factors for wind farms during periods of maximum demand. This resulted due to no planting of additional generation to support increasing demand forecasts as is done in the ISP. Studies performed for the PADR will incorporate additional planted generation and follow the optimal development path from the ISP.

B. For the PSCR, new interconnectors have assumed flow rates consistent with existing interconnectors of relevant regions. However, PADR studies are expected to include time-sequential data aligned to the ISP.

All studies completed as part of the PADR assessment are expected to incorporate the latest publications on the AEMO Generation Information and the NEM Transmission Augmentation Information web pages.

[19] AEMO, 2024 VAPR, October 2024, p 13.

[20] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[21] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[22] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

3 Credible options

This section provides detail on each of the credible options considered capable of addressing the identified need, outlining their estimated capital and operational and maintenance costs, land, environment and social considerations, earliest delivery timing and consideration of any material inter-network impact.

This section also outlines the technical characteristics that a non-network solution would need to provide to meet the identified need.

3.1 Development of credible options

The process for developing the credible options is summarised below:

1. Identify network limitations → 2. Identify set of possible solutions to network limitations → 3. Identify fault level mitigation required following implementation of solutions → 4. Consider the commercial and technical feasibility of possible solutions forming an option → 5. Work closely with other NSPs to ensure overall solutions are determined consider there requirements

For each of the four network limitations in Section 2.2, AVP identified possible solutions that, combined with each other, form credible options that are expected to be capable of meeting the identified need. These possible solutions are summarised in Table 3, and are used as components of the credible network options in Section 3.2. AVP will continue to closely work with Powercor and AusNet as they develop the proposed investments discussed in section 2.1, alongside further development of the PADR for this RIT-T.

Table 3 Solutions to manage thermal limitations

Thermal limitation	Possible solutions
#1 Short-term rating exceeded of the Moorabool – Geelong 220 kV circuits for outage of a parallel circuit	• Uprate the Geelong – Moorabool 220 kV lines; **or** • Build a third 220 kV line between Geelong and Moorabool
#2 Short-term rating exceeded of the Geelong – Deer Park circuit for outage of the Deer Park – Keilor line and similarly, short-term rating exceeded of the Deer Park – Keilor 220 kV circuit for outage of the Geelong – Deer Park circuit	• Cut existing Geelong – Keilor lines into Deer Park Terminal Station; **and** • Operate Deer Park – Keilor lines as normally open (this also assists with limitation #1)
#3 Short-term rating exceeded of the Geelong – Keilor 220 kV circuit for outage of a parallel circuit	
#4 Short-term rating exceeded of the 500/220 kV transformers at Keilor post credible contingencies	• Replace the three Keilor 500/220 kV 750 MVA transformer banks with 1,000 MVA units • Like for like replacement of the three Keilor 500/220 kV 750 MVA transformers with modern transformers that have 150% short term rating

The existing transformers at Keilor Terminal Station are high impedance to mitigate fault levels. The option of replacing them with standard 1,000 MVA transformers is expected to lead to fault level increases due to the lower impedance of these transformers. Potential strategies to mitigate these fault level increases include:

- Specification of high impedance transformers.
- Opening bus ties at affected terminal stations, to operate certain stations in a split-bus arrangement[23].
- Rearranging the network to tie stations together via different lines.
- Installing fault level mitigation equipment such as series or neutral earth reactors/resistors.
- Replacing low fault current rated assets with higher capacity assets.

Replacing low fault current rated assets with higher capacity assets at the impacted terminal stations has been included as a component of the credible options set out below. The specific fault level mitigation action that would be adopted will be considered in more detail as part of the PADR and PACR assessments, which will also allow AVP to further refine the indicative fault level mitigation cost estimates included in this PSCR.

3.2 Network options

This section describes the two credible network options that AVP has identified to meet the identified need. It also outlines two other network options that have been considered but will not be progressed to the next stage of the RIT-T process, because they are not considered to meet the identified need from a technical or commercial perspective[24].

The options, including their costs and optimal timing, will be refined at the PADR stage based on further investigations. At the PADR stage, AVP intends to further investigate:

- Any practicality issues, such as site-specific constraints.
- Combinations of network and non-network solutions to determine the option or hybrid option that maximises net economic benefits.
- The potential impact that a change in status of currently uncommitted connection applications for generation and storage in the greater western metropolitan Melbourne area may have on the identified need being addressed by this RIT-T.
- Interactions between the credible options identified in this RIT-T and the credible options put forward in the AusNet's RIT-T relating to replacement of the Keilor Terminal Station 500/220 kV transformers[25] and in any forthcoming Powercor RIT-T regarding investment at Deer Park – discussed in Section 2.1.
- Alternatives to the fault level mitigation strategies presented in Section 3.1.

The two credible network options and their subcategories discussed below are summarised in Table 4.

[23] This strategy decreases reliability further downstream in the power system and is usually considered a last resort

[24] As per NER 5.15.2(a).

[25] AusNet, *Maintaining reliable transmission network services at Keilor Terminal Station*, RIT-T PSCR, July 2024.

Table 4 Summary of credible options

Subcategory	Moorabool – Geelong	Geelong – Deer Park – Keilor	Keilor transformers	Total cost
Option 1				
1A	Uprate the Geelong - Moorabool 220 kV double circuit line	Cut existing Geelong to Keilor circuits into Deer Park Operate Deer Park to Keilor as normally open	Like for like replacement of the three Keilor 500/220 kV 750 MVA transformers with modern transformers that have 150% short term rating	$73.6 million
1B			Replace the three Keilor 500/220 kV 750 MVA transformers with 1,000 MVA transformers Equipment replacements at stations that have fault level exceedances – works are expected to be at the 220 kV level at West Melbourne Terminal Station and at the 66 kV level at Fishermans Bend and Keilor Terminal Stations.	$127.5 million
Option 2				
2A	Establish a third 220 kV circuit between Geelong and Moorabool	Cut existing Geelong to Keilor circuits into Deer Park Operate Deer Park to Keilor as normally open	Like for like replacement of the three Keilor 500/220 kV 750 MVA transformers with modern transformers that have 150% short term rating	$119.7 million
2B			Replace the three Keilor 500/220 kV 750 MVA transformers with 1,000 MVA transformers Equipment replacements at stations that have fault level exceedances – works are expected to be at the 220 kV level at West Melbourne Terminal Station and at the 66 kV level at Fishermans Bend and Keilor Terminal Stations.	$173.6 million

3.2.1 Option 1 – Deer Park cut in, Geelong - Moorabool 220 kV line uprate and Keilor transformer replacement

Option 1 can be broken into four elements and has subcategories 1A and 1B which vary the fourth element. The components of Option 1A are set out in Table 5 and the components of Option 1B are set out in Table 6.

- **The first element – cutting the existing Geelong to Keilor circuits into Deer Park –** will double the supply capacity to Deer Park Terminal Station to supply the forecast demand growth at Deer Park during peak demand periods. It involves cutting the two 220 kV circuits that currently run between Geelong and Keilor (see Figure 6) into Deer Park, which will require expansion of the 220 kV switchyard and bridging spans of conductors from the circuits into the Deer Park Terminal Station.
- **The second element – operating the Deer Park to Keilor circuits as normally open –** will, combined with the first element, avoid constraints on wind generation from the V3 and V4 REZs supplying greater Melbourne during periods of high demand when the 220 kV network is already heavily loaded. This involves operating the circuit breakers connecting the Deer Park to Keilor circuits as normally open such that Deer Park is supplied radially from Geelong (that is, Deer Park will not be supplied via the 500 kV network through Keilor). This avoids supply from wind generation to greater Melbourne travelling through the Moorabool to Keilor 220 kV corridor by redirecting flows along the 500 kV network.
  - This arrangement also helps mitigate fault levels at the Geelong and Keilor terminal stations and facilitates a System Overload Control Scheme (SOCS) on the Moorabool – Geelong circuits by allowing the loading of these lines to be more effectively controlled through shedding load at Deer Park or Geelong terminal stations in the event of a contingency.

- **The third element – uprating the two existing Geelong to Moorabool 220 kV lines –** will enable secure supply to Geelong and Deer Park terminal stations during peak demand periods, which are expected to occur during high temperatures. In particular, it is expected that the uprating can increase the N-1 capacity of each circuit during 45°C temperatures from 720 MVA to 1,079 MVA. The uprating is expected to involve replacement of any low rated interplant elements, installing wind monitoring and installing a SOCS.
  - As part of the PADR, AVP will undertake further investigations to ensure that this uprating is sufficient to remove the risk of thermal limitations, or whether additional elements may be required.
- **The fourth element – replacing the three Keilor 500/220 kV 750 MVA transformers –** is required to avoid thermal limitations on the Keilor transformers during peak demand periods in the western metropolitan Melbourne area. It is required to supply Keilor, West Melbourne, Fishermans Bend, Altona, and Brooklyn terminal stations. The need for and cost of this element relative to the base case is dependent on the outcome of AusNet's separate RIT-T, discussed in Section 2.1 above.
  - Option 1A - for this RIT-T, it is assumed that the like for like replacement of 750 MVA transformers by 2029, at a cost of $140 million, is identified as the preferred option under AusNet's RIT-T. Therefore, there is no additional cost included for the like for like replacement of the Keilor transformers under Option 1A due to this cost and benefit already being included in the base case of this RIT-T.[26]
  - Option 1B - as part of Option 1B, AVP will assess the differential cost and benefit of instead replacing the 750 MVA transformers with 1,000 MVA transformers. The proposed 1,000 MVA replacements are the standard higher capacity units that are utilised across other 500/220 kV terminal stations in Victoria, which allows for in service spare capacity and a shared spare phase available from Moorabool Terminal Station. These units have a lower impedance than the existing Keilor transformers which will increase fault currents into Keilor and the downstream terminal stations. AusNet estimates the cost to replace the three Keilor transformers with 1,000 MVA transformers is $150 million, AVP has therefore applied an incremental replacement upgrade cost of $10 million for this option, over the like for like replacements.[27] AVP has also included an estimated cost of the fault level mitigation works required due to the transformer upgrade within the components for Option 1B. This cost estimate has been developed based on the assumption that site equipment is replaced, which is likely to be the lowest cost solution to mitigate the increased fault currents. The precise nature of the works that will be undertaken to mitigate fault level increases will be refined ahead of the PADR. Alternative fault mitigation options, such as consideration of non-standard higher impedance transformers, line cut ins and opening bus ties to operate certain stations in a split bus configuration, will also be considered, with the feasible option that maximises net economic benefit to be adopted.

Table 5 Option 1A capital cost components

Option 1A components	Key element/s of identified need	Estimated capital cost ($ million, real 2024)
Cut existing Geelong to Keilor circuits into Deer Park	Limitation #2	66.1
Operate Deer Park – Keilor circuits as normally open	Limitation #1, #2 and #3	-

[26] AusNet, *Maintaining reliable transmission network services at Keilor Terminal Station*, RIT-T PSCR, July 2024, p 7.

[27] If the transformers are upgraded to 1,000 MVA transformers, a spare unit is not needed, because the larger units will allow for in-service spare capacity and a shared spare phase is also available from Moorabool Terminal Station. AusNet, *Maintaining reliable transmission network services at Keilor Terminal Station*, RIT-T PSCR, July 2024, p 7.

Option 1A components	Key element/s of identified need	Estimated capital cost ($ million, real 2024)
Uprate the Geelong - Moorabool 220 kV line	Limitation #1	7.5
Like for like replacement of the three Keilor 500/220 kV 750 MVA transformers with modern transformers that have 150% short term rating	Limitation #4	-
Total		73.6[A]

A. Total includes known and unknown risk allowances of approximately $15.5 million (excludes any known or unknown risk costs for Keilor replacement).

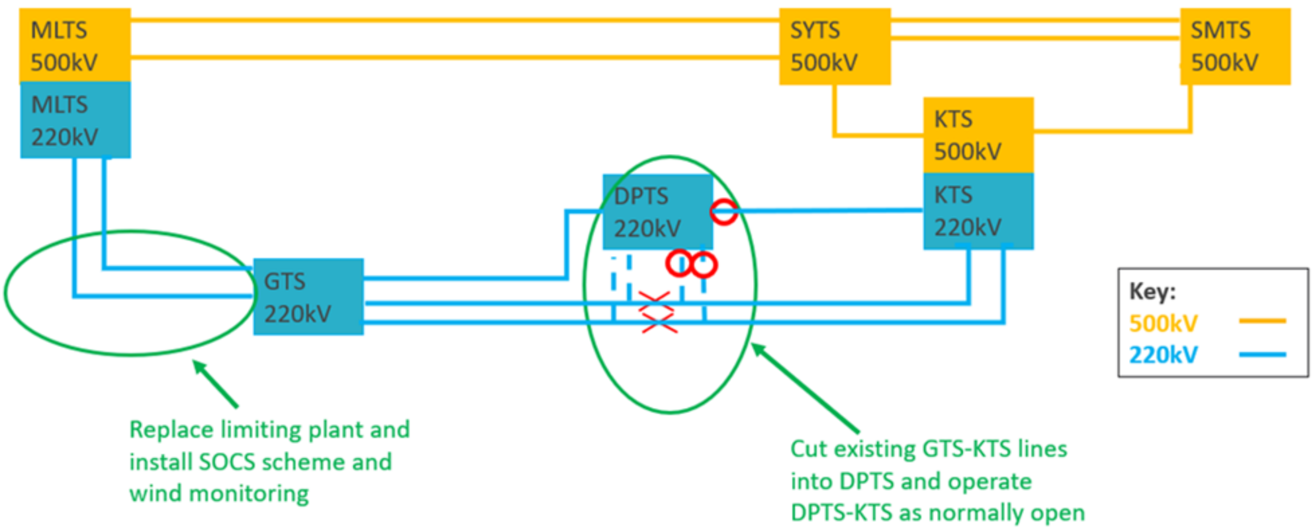
Table 6 Option 1B capital cost components

Option 1B components	Key element/s of identified need	Estimated capital cost ($ million, real 2024)
Cut existing Geelong to Keilor circuits into Deer Park	Limitation #2	66.1
Operate Deer Park – Keilor circuits as normally open	Limitation #1, #2 and #3	-
Uprate the Geelong - Moorabool 220 kV line	Limitation #1	7.5
Replace the three Keilor 500/220 kV 750 MVA transformers with 1,000 MVA transformers and perform fault level mitigation works	Limitation #4	10 for transformer upgrade 43.9 for fault level mitigation
Total		127.5[A]

A. Total includes known and unknown risk allowances of approximately $23.7 million (excludes any known or unknown risk costs for Keilor replacement).

The components of option 1A and 1B are shown in Figure 6.

Figure 6 Option 1A and 1B network diagram



In addition to the capital cost, AVP estimates the annual operating and maintenance expenditure for Option 1A and Option 1B to be 1% of the total capital cost estimate of network components, which is aligned with the 2023 *Transmission Expansion Options Report*[28].

[28] Section 5.3 discusses the Transmission Cost Database (TCD), which was updated as part of the 2023 *Transmission Expansion Options Report*. At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Option 1A and Option 1B are expected to address the identified need by reducing constraints on wind generation in the west of Victoria, thereby allowing it to better supply greater Melbourne during peak demand periods, and by increasing the capacity in the western metropolitan Melbourne network above that required to maintain reliable and secure supply under 10% POE demand forecasts beyond the 15-year planning horizon. In particular, the western metropolitan network capacity during 45°C summer temperatures is expected to increase from 2,700 MW to approximately 3,500 MW following commissioning of Option 1A or approximately 3,600 MW following commissioning of Option 1B. The benefits associated with Option 1A and Option 1B will be assessed in detail as part of the PADR.

3.2.2 Option 2 – Deer Park cut in, Geelong to Moorabool third 220 kV circuit establishment and Keilor transformer replacement

Option 2 can be broken into four elements and has subcategories 2A and 2B which vary the fourth element. The components of Option 2A are set out in Table 7 and the components of Option 2B are set out in Table 8.

- The first and second elements – cutting the Geelong to Keilor circuits into Deer Park and operating the circuit breakers connecting Deer Park and Keilor as normally open – are the same as for Option 1. AVP considers that these elements are required to supply forecast demand growth at Deer Park and minimise constraints on wind generation from the V3 and V4 REZs to allow them to better supply greater Melbourne.
- **The third element – establishing a third 220 kV circuit between Geelong and Moorabool –** will enable secure supply to Geelong and Deer Park terminal stations during peak demand periods, which typically occur during high ambient temperatures conditions. For cost estimating purposes, it has been assumed that this third circuit would be established by building a new double circuit line with only the first circuit strung at this stage since that provides sufficient additional N-1 capacity to remove the thermal limitation on the existing Geelong - Moorabool 220 kV circuits. It is anticipated that the second circuit will be required at some point in the future to allow for additional demand growth in the western metropolitan Melbourne network.
  - Establishing a third circuit will provide an additional capacity increase relative to uprating the existing line as proposed under Option 1. It is expected that establishing a third circuit could increase the N-1 capacity during 45°C ambient temperatures from 720 MVA to 1,440 MVA (an additional 361 MVA benefit compared to the 1,079 MVA capacity anticipated from the line uprating proposed under Option 1).
- **The fourth element** – **replacing the three Keilor 500/220 kV 750 MVA transformers** – is the same as for Option 1. Option 2A will consider the like for like replacement of the 750 MVA transformers at Keilor with no additional cost included due to the inclusion of this augmentation in the base case of this RIT-T (as discussed in section 2.1). Option 2B will consider the replacement of the 750 MVA transformers with 1,000 MVA transformers and include the incremental replacement upgrade cost of $10 million plus the costs of fault mitigation works required to facilitate the transformer upgrade.

Table 7 Option 2A capital cost components

Option 2A components	Key element/s of identified need	Estimated capital cost ($ million, real 2024)
Cut existing Geelong to Keilor circuits into Deer Park	Limitation #2	66.1
Operate Deer Park – Keilor circuits as normally open	Limitation #1, #2 and #3	-

Option 2A components	Key element/s of identified need	Estimated capital cost ($ million, real 2024)
Establish a third 220 kV circuit between Geelong and Moorabool	Limitation #1	53.6
Like for like replacement of the three Keilor 500/220 kV 750 MVA transformers with modern transformers that have 150% short term rating	Limitation #4	-
Total		**119.7[A]**

A. Total includes known and unknown risk allowances of approximately $33.1 million (excludes any known or unknown risk costs for Keilor replacement)

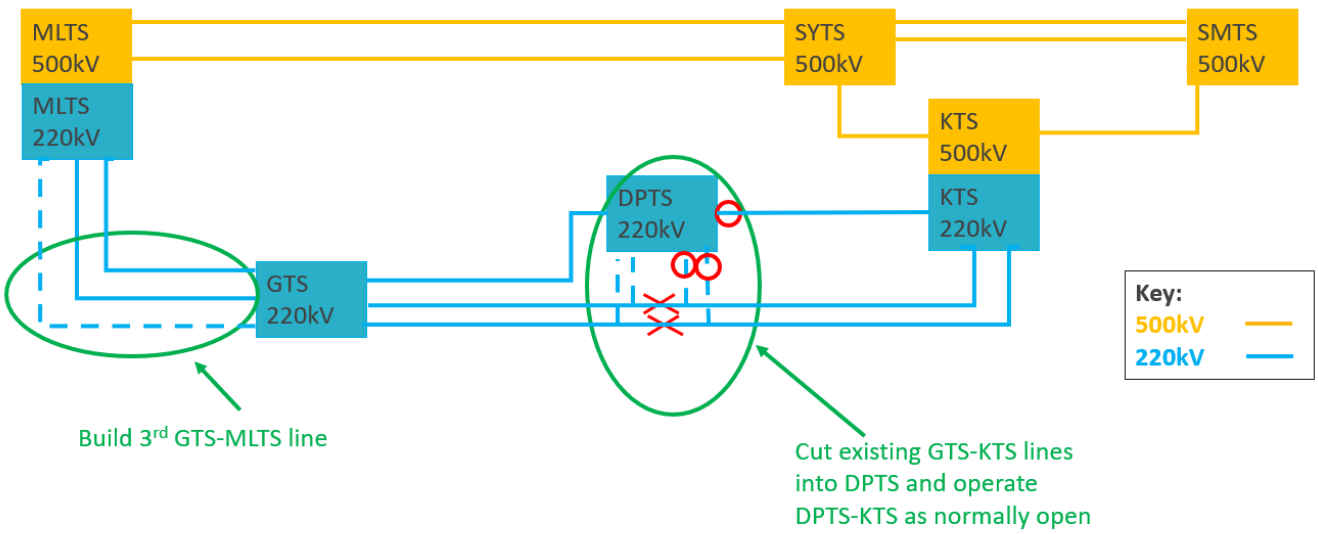
Table 8 Option 2B capital cost components

Option 2B components	Key element/s of identified need	Estimated capital cost ($ million, real 2024)
Cut existing Geelong to Keilor circuits into Deer Park	Limitation #2	66.1
Operate Deer Park – Keilor circuits as normally open	Limitation #1, #2 and #3	-
Establish a third 220 kV circuit between Geelong and Moorabool	Limitation #1	53.6
Replace the three Keilor 500/220 kV 750 MVA transformers with 1,000 MVA transformers and perform fault level mitigation works	Limitation #4	10 for transformer upgrade 43.9 for fault level mitigation
Total		**173.6[A]**

A. Total includes known and unknown risk allowances of approximately $41.3 million (excludes any known or unknown risk costs for Keilor replacement)

The components of option 2A and 2B are shown in Figure 7.

Figure 7 Option 2A and 2B network diagram



In addition to the capital cost, AVP estimates the annual operating and maintenance expenditure for Option 2 to be 1% of the total capital cost estimate of network components, which is aligned with the 2023 *Transmission Expansion Options Report*[29].

[29] Section 5.3 discusses the Transmission Cost Database (TCD), which was updated as part of the 2023 *Transmission Expansion Options Report*. At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Option 2A and Option 2B are expected to address the identified need by reducing constraints on wind generation in the west of Victoria, thereby allowing those generators to better supply greater Melbourne during peak demand periods, and by increasing the capacity in the western metropolitan Melbourne network above that required to maintain reliable and secure supply under 10% POE demand forecasts beyond the 15-year planning horizon. In particular, the western metropolitan network capacity during 45°C summer temperatures is expected to increase from 2,700 MW to approximately 3,500 MW following the commissioning of Option 2A or 3,980 MW following commissioning of Option 2B. The benefits associated with Option 2A and Option 2B will be assessed in detail as part of the PADR.

3.2.3 Indicative construction time and earliest possible commission dates

Table 9 sets out the estimated construction time and earliest possible commissioning date for each option, based on AVP's observations and experience in similar projects. AVP will undertake further analysis as part of the PADR to determine the optimal commissioning dates, based on economic timing, for each option and its solution components, which may result in changes to the information presented in Table 9.

Table 9 Indicative construction timelines and potential commissioning dates (task complete by dates)

Task description	Line cut in / uprate	New line	Fault mitigation	New transformer
Regulatory investment test process	Q1-2025 to Q4-2025			
Early works/ contract negotiation	Q1-2026 to Q4-2026			
Design, approvals and long lead procurement	Q1-2027 to Q1-2028	Q1-2027 to Q4-2028	Q1-2027 to Q1-2028	Delivery and commissioning anticipated 2029[A]
Construction	Q2-2028 to Q3-2028	Q1-2029 to Q1-2030	Q2-2028 to Q3-2028	
Commissioning	Q4-2028 to Q1-2029	Q2-2030 to Q4-2030[B]	Q4-2021 to Q1-2029	

A. Estimated completion date in AusNet's 2024 Asset Renewal Plan at https://wa.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report. Final preferred completion date to be considered through further joint planning between AusNet and AVP and confirmed through AusNet's 'Maintaining reliable transmission network services at Keilor Terminal Station' RIT-T and later stages of this RIT-T.
B. Indicative timeframes are subject to change. AVP intends to further refine construction timeframes and undertake joint planning with asset owners to inform development of the PADR.

3.2.4 Options considered but not progressed

Table 10 summarises the network options that AVP considered during the feasibility studies undertaken for this RIT-T but did not include in this PSCR, with the reasons why AVP considers those options not to be commercially and/or technically feasible[30].

Table 10 Options considered but not progressed

Description	Reason(s) for not progressing
Establish Truganina Terminal Station	This option looked at creating a new 500/220 kV terminal station at the existing Truganina site in the western metropolitan Melbourne area. There are 500 kV lines already near the site and easements already exist for potential connection of existing lines, there is also an unused easement from the Truganina site to Deer Park Terminal Station which could allow for the installation of Truganina – Deer Park 220 kV lines. Power flow studies demonstrated that the Deer Park cut in to the Geelong – Keilor 220 kV circuits would be required with this option to prevent thermal limitations on the Geelong – Deer Park – Keilor 220 kV circuits.

[30] As per NER 5.15.2(a).

Description	Reason(s) for not progressing
	Additionally, the Moorabool – Geelong 220 kV line and the Keilor 500/220 kV transformers require upgrading to achieve a significant increase in the western metropolitan Melbourne network capacity. The lowest cost Truganina Terminal Station option that was considered included all the works in Option 2 with the addition of cutting the new 500/220 kV Truganina Terminal Station into the Moorabool – Sydenham 500 kV lines, installing one 1,000 MVA 500/220 kV transformer at Truganina and connecting a single 800 MVA 220 kV line from Truganina to Deer Park. The estimated capital cost of these works is $368.7 million, which is $228.4 million more than Option 2. The network capacity increase provided by Option 2 is estimated to be sufficient for the current forecast demand growth in the western metropolitan Melbourne area. Therefore, when considering the identified need for this RIT-T, the cost of completing the additional works to establish Truganina Terminal Station cannot be considered commercially feasible as it will not provide enough additional benefits.
Reinforce the 220 kV network between Geelong – Deer Park – Keilor	This option looked at completing the Deer Park cut in to the Geelong – Keilor 220 kV circuits and then replacing the low rated circuits with higher rated 800 MVA circuits. This would allow for the 220 kV corridor between Geelong – Deer Park – Keilor to be operated in parallel to the 500 kV network as it currently is. Power flow studies assessing this option demonstrated that an additional 220 kV double circuit line, with 800 MVA rating per circuit, from Moorabool to Geelong would be needed to facilitate the additional power flow through the 220 kV network to Keilor. Additionally, the Keilor 500/220 kV transformer upgrade is still required to maximise the network capacity increase provided with this option. The estimated capital cost to complete these works is $226.7 million, assuming that the existing towers could be uprated via reconductoring, or $425.7 million, assuming the existing towers need to be replaced[A]. When compared to Option 2 this is $86.4 million more if the towers can be uprated or $285.4 million more if the towers need replacing. Reconducting existing towers to uprate this line may not be technically feasible due to factors such as age, condition and tower structure. Under current demand forecasts the estimated network capacity increase provided by Option 1 or Option 2 is expected to be sufficient to meet the identified need of this RIT-T and they cost considerably less than this option. Therefore, this option is not considered commercially feasible as it does not provide enough additional benefits to justify the cost of performing the additional works.

A. Cost estimate for full tower replacement does not include network outage costs or the costs to decommission and dismantle existing towers.

3.3 Non-network options

3.3.1 Description of credible non-network options

A suite of non-network options may be capable of meeting or partially meeting the identified need, including:

- Demand response and decentralised storage.
- Grid-connected generators and BESS.

Due to the interconnected nature of the western metropolitan Melbourne network, there is no single location for a non-network solution that can resolve all limitations identified in Section 2.2 above. For example, a BESS located at Geelong Terminal Station generating at periods of peak demand can reduce the loading on the Moorabool – Geelong 220 kV line but would increase the loading on the Geelong – Keilor 220 kV line. Therefore, to effectively resolve all the limitations identified, several non-network solutions located at different sites in the western metropolitan area are required. The peak MW size requirements presented in Section 3.3.2 would be spread across these projects.

AVP will carefully review all submissions regarding possible non-network options and assess how combinations of network and non-network components could form credible options as part of the PADR.

While AVP expects that the forecast demand growth can be addressed by non-network options, the increased flows through the western metropolitan corridor associated with the transition from fossil fuels to renewable generation may not be addressable by non-network options on their own. For example, the need for investment in the Geelong – Moorabool corridor could be deferred by a non-network option. However, the need to undertake works between Geelong and Keilor to promote flows on the 500 kV network rather than the Moorabool – Keilor 220 kV corridor may not be substitutable for a non-network option.

Demand response and decentralised storage

The demand level can be reduced during high demand periods by encouraging and promoting demand response, load shifting, coordinated discharging of decentralised storage, and contracted discharging of grid-scale storage. It is conceptually possible to alter the demand during high demand periods, when network capacity is expected to be exceeded, by utilising flexible loads such as hot water and pool pumps or certain industrial loads in addition to emerging flexible loads such as electric vehicles and distributed storage.

An effective load shift at times of high demand is an alternative to increasing the network limit in addressing the identified need. AVP is seeking information from potential providers that may have sufficient capability to decrease load on the network, such as large pump loads or batteries, during periods of high demand. See Section 3.3.2 for details of the technical characteristics required of a non-network solution, including the times at which the solution would need to reduce load, and Section 3.3.3 for details of the information that AVP is seeking from potential non-network solution providers.

Grid connected generators and storage

As described in Section 2.2, the Moorabool – Geelong 220 kV circuit loading is forecast to exceed its N-1 short-term rating following the contingent loss of the other Moorabool – Geelong 220 kV circuit in summer 2025-26. An example of a non-network solution to this limitation would be a BESS connected at Geelong Terminal Station contracted to generate at periods of peak demand, thereby managing the load at risk and deferring the network option of upgrading the Geelong – Moorabool line capacity.

AVP is seeking submissions from generator or BESS proponents with a connection in an appropriate location who have the potential to defer the identified need and who are a potential proponent of a non-network solution. See Section 3.3.2 for details of the technical characteristics required of a non-network solution, including the times at which the solution would need to reduce load, and Section 3.3.3 for details of the information that AVP is seeking from potential non-network solution providers.

3.3.2 Technical characteristics required of a network or non-network option

Table 11 summarises the size, operating profile and timing requirements for non-network solutions connected across the western metropolitan network in aggregate.

AVP encourages submissions from all non-network solutions located in the western metropolitan Melbourne area including, but not limited to, West Melbourne, Fishermans Bend, Brooklyn, Altona, Deer Park, Geelong and Keilor. All submissions will be assessed at the PADR stage to determine if a combination of non-network options or non-network and network options can maximise the net economic benefit.

Table 11 Summary of technical requirements for non-network solutions

Financial year	Size (MW)[A]	Time of day[B]	Period of availability	Maximum consecutive hours of dispatch[C]
2025-26	130	Evening Peak	December to February	1.5
2026-27	210	Evening Peak	December to February	2
2027-28	260	Evening Peak	December to February	2
2028-29	310	Evening Peak	December to February	2
2029-30	350	Evening Peak	December to February	2.5
2030-31	370	Evening Peak	December to February	2.5
2031-32	415	Evening Peak	December to February	2.5
2032-33	460	Evening Peak	December to February	2.5
2033-34	470	Evening Peak	December to February	2.5

A. MW power injection required to resolve western metropolitan Melbourne network limitations based on a 10% POE maximum demand forecast.
B. Evening peak refers to the hours between 3.00 pm and 9.00 pm.
C. Maximum consecutive duration where network support would be required based on 10% POE demand forecast, noting that additional smaller durations may also occur in any given year. For example, the table shows that a combination of BESS in different locations with combined power of 350 MW and 2.5 hours of storage capacity would be required to meet the identified need in 2029-30.

3.3.3 Information to be provided by proponents of a non-network option

The above is not an exhaustive list of potential non-network services. AVP welcomes proponents of potential non-network solutions to make submissions on any non-market ancillary services (NMAS) they can provide to address the identified need outlined in this PSCR. Submissions should include details on:

- Organisational information.
- Relevant experience.
- Details of the service, including size (MW and megawatt hour [MWh] capacities), connection point location and any restrictions on how often and when the service can be called on.
- Cost of service, separating capital, operational expenditure, and risk and return costs.
- Confirmation of timelines in providing the service.
- Details of the proposed solutions' commitment status against the RIT-T glossary definitions of Committed Project and Anticipated Project[31].

3.4 Material inter-network impact

AVP considered whether the credible options are expected to have a material inter-network impact[32].

A 'material inter-network impact' is defined in the NER[33] as:

> *a material impact on another Transmission Network Service Provider's network, which may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's*

[31] AER, Regulatory Investment Test for Transmission, August 2020, p.13, at https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

[32] As per NER 5.16.4(b)(6)(ii).

[33] See Chapter 10 of the NER.

network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network.

In its Inter-Network Test Guidelines[34], AEMO suggests a screening test to indicate whether or not a transmission augmentation has a material inter-network impact. Applying this screening test, no material inter-network impact can be assumed if the transmission augmentation satisfies any of the following:

- A decrease in power transfer capability between transmission networks or in another transmission network service provider's (TNSP's) network of no more than the minimum of 3% of the maximum transfer capability and 50 MW.
- An increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW.
- An increase in fault level by less than 10 MVA at any substation in another TNSP's network.
- The investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

AVP considers that the credible options presented in this PSCR satisfy these conditions, as they will only have localised effects around the western metropolitan Melbourne region of Victoria. By reference to AEMO's screening criteria, there is no material inter-network impact associated with any of the credible options identified.

3.5 Land, environmental and social considerations

Section 3.2 of this PSCR outlines cost factors and indicative construction and commissioning timeframes for network options. It should be noted that information presented in the PSCR is at a point in time and is subject to change.

AVP acknowledges new transmission lines may create concern with communities regarding the potential impacts during construction and operation. AVP is committed to providing information that is accessible to ensure interested parties can be informed and use the RIT-T consultation process to participate. Any feedback to the PSCR will help AVP's investigation and consideration of which credible options can best meet the power system needs and that minimises disruption to communities. As required, AVP will consider how to best to engage with interested parties prior to the publication of the PADR. This will be important if a new transmission line between Moorabool and Geelong is identified to be a credible option to help meet the power system needs outlined in this PSCR.

AVP recognises the credible options outlined in Section 3.2 (excluding new potential Moorabool – Geelong line) are proposed to be constructed and operated in locations already hosting existing terminal stations. These locations have limited residential interface (based on desktop studies to date) and it is on this basis that AVP has formed an initial view that these proposed credible options are not likely to generate significant social license risks for communities surrounding these existing terminal stations. AVP plans to engage with terminal station owners during the PSCR consultation period to assist with developing the PADR.

[34] See AEMO, *Inter-Network Test Guidelines*, October 2023, at https://aemo.com.au/-/media/files/electricity/nem/system-operations/inter-network-testing/inter-network-test-guidelines-v22-clean.pdf?la=en.

AVP plans to develop the PADR with updated information about land assembly options, environment, planning and social constraints for the credible options identified. This information will contribute to refining relevant cost factors and time allowances for obtaining planning and environment approval (if required) prior to the construction of credible option.

4 Materiality of market benefits

AVP notes the NER requirement 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:

- 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.

4.1 Material classes of market benefits

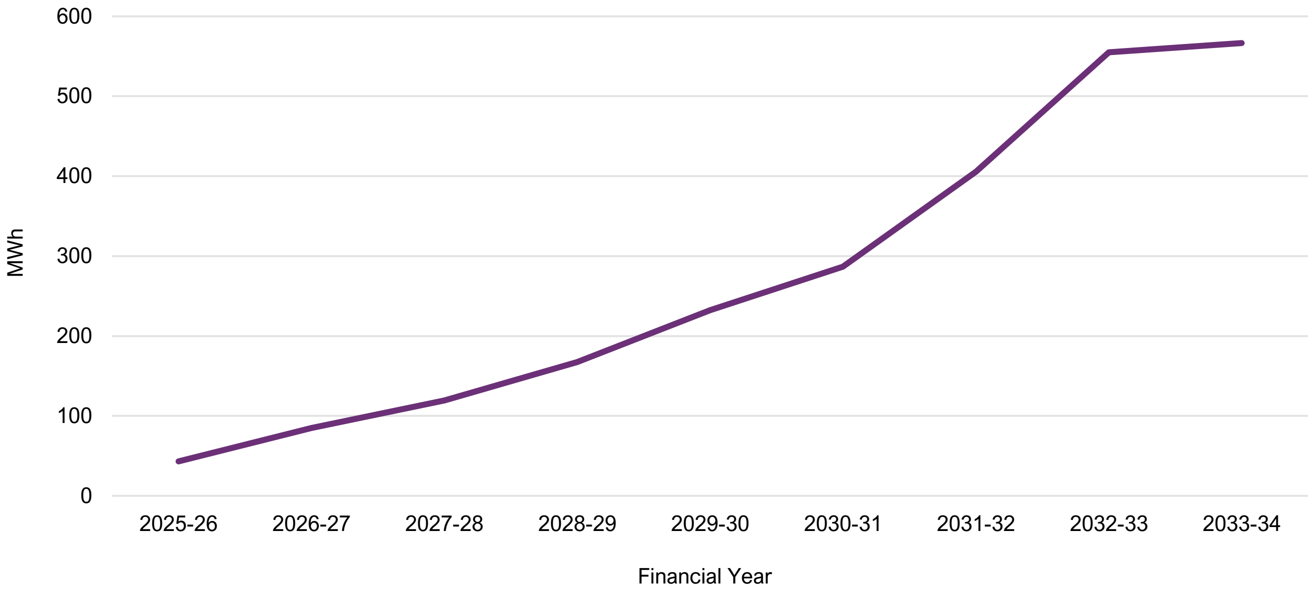
Three classes of market benefits are expected to be material for this RIT-T:

- Involuntary load curtailment.
- Avoided unrelated network investment.
- Wholesale market benefits (subject to further investigation as part of the PADR).

Involuntary load curtailment

AVP considers that changes in involuntary load curtailment will be material to the RIT-T assessment. Involuntary load shedding is forecast to occur under the base case because demand is expected to exceed the capacity of the western metropolitan Melbourne network. Figure 8 provides an indicative estimate of forecast involuntary load shedding under the base case.

Figure 8 Indicative estimate of expected unserved energy under the base case, 2025-26 to 2033-34 (MWh)



As part of the PADR assessment, AVP intends to estimate the value of avoided EUSE under each of the credible options, compared to the base case. This will be valued using the Value of Customer Reliability (VCR) published by the Australian Energy Regulator (AER), as described in Section 5.5.

Avoided unrelated network expenditure

AVP expects that the investments contemplated in this RIT-T could avoid or delay the installation of a 100 MVAr shunt capacitor on the 220 kV level at Deer Park Terminal Station by 2031, which is part of the preferred option under AVP's Metropolitan Melbourne Voltage Management PACR published in December 2024[35]. This benefit will be further investigated and quantified in the PADR for this RIT-T.

Wholesale market benefits

AVP will further investigate whether wholesale market benefits are likely to be material to the RIT-T assessment. This investigation will consider the following categories of market benefits:

- Changes in fuel consumption arising through different patterns of generation dispatch.
- Changes in Australian greenhouse gas emissions.
- Changes in voluntary load curtailment.
- Changes in costs for parties other than AVP.

AVP expects that the options will have some impact on NEM dispatch. However, it is not clear at this stage whether that impact will be material to the outcome of this RIT-T. A proportionality and materiality assessment will be undertaken ahead of the PADR to determine whether wholesale market modelling, using software such as PLEXOS, will be valuable for this RIT-T. This assessment will take account of submissions to the PSCR, particularly regarding any non-network options and our assessment of credible options including a non-network component.

Depending on the expected materiality of any wholesale market benefits, a proportionate approach may be taken to estimating them (rather than full wholesale market modelling across all ISP scenarios). However, as discussed in Section 5.6 below, AVP will test the sensitivity of net present value (NPV) results to different demand scenarios in the PADR, regardless of whether wholesale market modelling is undertaken.

4.2 Other classes of market benefits not likely to be material

AVP considers that the following classes of market benefits are not material to the RIT-T assessment for any of the credible options:

- **Changes in network losses**, because any network losses outside of those inherently captured through the change in transmission capacity representing the benefit of each credible option are not expected to be material to the ranking of options.

[35] AEMO, Metropolitan Melbourne Voltage Management RIT-T PACR, at https://wa.aemo.com.au/-/media/files/initiatives/metropolitan-melbourne-voltage-management-rit/metropolitan-melbourne-voltage-management-pacr.pdf?la=en.

- **Option value**, because at this stage, AVP does not expect there to be any 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). AVP also notes that a significant modelling exercise would be required to estimate option value benefits, and that such an exercise would be disproportionate to the potential additional benefits for this RIT-T.
- **Changes in ancillary services costs**, because the estimated cost of undertaking the analysis to quantify these changes would likely be disproportionate to the scale of the credible options being considered in this report.
- **Competition benefits**, because the estimated cost of undertaking the analysis to quantify competition benefits would likely be disproportionate to the scale of the credible options being considered in this report.

5 Overview of proposed assessment approach

This section sets out AVP's proposed assessment approach to credible options in the PADR. It also provides more detail in Section 5.1 on the base case, which is the 'do nothing' reference point that all credible options will be assessed against under the RIT-T.

5.1 The base case

Consistent with the RIT-T requirements, AVP intends to compare the costs and benefits of each credible option to a 'do nothing' base case for each scenario. The base case is the projected case if no credible option investment is taken[36]:

> *"The base case is where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented"*

For this RIT-T, business as usual (BAU) activities are forecast to lead to significant unserved energy. While these are not situations that AVP plans to encounter, and this RIT-T has been initiated in order to avoid it, it is plausible that a small amount of involuntary load curtailment might be required in periods prior to an investment option becoming economically feasible. The RIT-T assessment is required under the NER to consider this base case as a common point of reference when estimating the net benefits of each credible option and, for a positive net benefit driven RIT-T, the base case is also considered a credible option.

Under the base case, the network supply capacity in the western metropolitan Melbourne network will remain at approximately 2,860 MW under average summer peak temperatures (35°C) and approximately 2,700 MW under extreme summer peak temperatures (45°C).

5.2 Assessment parameters

AVP intends to adopt a 15-year assessment period from FY2025-26 to FY2039-40 for this RIT-T analysis. AVP considers this timeframe to be appropriate given the size and complexity of the proposed options and the increasing uncertainty associated with supply in the V3 and V4 REZs and surrounding areas to support the energy transition from the mid-late 2030s.

Where the capital components of the options considered have an asset life extending beyond the end of the assessment period, the net present value (NPV) modelling will include a terminal value to capture the remaining functional asset life. This ensures that the capital cost of long-lived assets over the assessment period is appropriately captured, and that all assets have their costs assessed over a consistent period irrespective of type,

[36] AER, *Regulatory Investment Test for Transmission Application Guidelines*, November 2024, p. 21, at https://www.aer.gov.au/industry/registers/resources/reviews/2024-review-cost-benefit-analysis-and-regulatory-investment-test-guidelines.

technology, or serviceable asset life. The terminal values will be calculated based on the undepreciated value of capital costs at the end of the analysis period and expected operating and maintenance cost for the remaining asset life.

A real, pre-tax discount rate of 7% per annum will be adopted as the central assumption for the NPV analysis, consistent with AEMO's latest *Inputs, Assumptions and Scenarios Report* (IASR)[37]. The RIT-T requires that sensitivity testing be conducted on the discount rate and that the equivalent weighted average cost of capital (WACC) be used as the lower bound. The PADR will therefore test the sensitivity of the results to a lower bound discount rate equal to the equivalent WACC (pre-tax, real) in the latest final decision by the AER for a transmission business in the NEM as of the date of the analysis (3.63% at publication of this PSC) [38]. lower bound discount rate of 3.63%. AVP will also adopt an upper bound discount rate of 10.5% (the upper bound in the latest IASR)[26].

5.3 Approach to estimating option costs

The capital costs quoted in this PSCR have been developed to a class 5B (+/- 50% accuracy) estimate using AEMO's latest Transmission Cost Database (TCD) and have been escalated to June 2024 dollar terms based on CPI[39]. The TCD is substantially based on the Association for Advancement of Cost Engineering (AACE) international classification system commonly used in many industries[40].

Desktop site assessments were undertaken to inform the likely build component for each option and, where relevant, the connection arrangement equipment costs have also been included. The cost of each option includes the following components:

- Project management.
- Engineering support.
- Equipment and services procurement.
- Installation.
- Commissioning and testing.
- Known and unknown risk allowances, in line with the TCD, which is presented as a proportion ($ million) of the total costs for credible options in Table 5 to Table 8 in Section 3.2 and is considered a contingency in line with AEMO's Mott MacDonald: Transmission Cost Database Update final report released in July 2023[41].

The TCD enables the selection of known and unknown risks for each build component to reflect the level of project complexity and risks that will or could arise during further development of credible options:

[37] AEMO, 2023 IASR, September 2023, p 123.

[38] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (TasNetworks) as of the date of this analysis, see AER, TasNetworks – 2024-29 – Final decision – PTRM, April 2024, WACC sheet, at https://www.aer.gov.au/industry/registers/determinations/tasnetworks-determination-2024-29/final-decision

[39] AEMO, 2023 IASR, September 2023, pp 23-24; Transmission Cost Database version 4-0, March 2023.

[40] The approach taken in the TCD differs from the AACE system in two superficial ways – see AEMO, 2023 *Transmission Expansion Options Report*, September 2023, p 21, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[41] As referenced in AEMO Transmission Cost Database, Building Blocks Costs and Risk Factors Update Final Report, 24 July 2023 prepared by Mott MacDonald, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/transmission-cost-database.

- Known risks:
  - Compulsory acquisition.
  - Cultural heritage.
  - Environmental offset risks.
  - Macroeconomic influences.
  - Market activity.
  - Geotechnical conditions.
  - Outage restrictions.
  - Weather delays.
- Unknown risks:
  - Productivity and labour costs.
  - Plant procurement costs.
  - Project overheads.
  - Scope and technology.

Known and unknown risks will be refined as AVP completes further investigations into the constructability and operation of each credible option. AVP notes that the estimates of fault level mitigation costs will be further refined as the RIT-T progresses because the precise nature of the works is not yet known.

The TCD produces indirect costs, calculated as a percentage of overall build costs (overall project capex). The value of indirect costs is calculated based on the selection of known and unknown risks, which includes consideration of factors such as brownfield or greenfield location of works, the contract delivery method and stakeholder sensitivity. Indirect costs in the TCD are attributed to costs that may be required prior to delivery of a credible option, including:

- Project development.
- Works delivery.
- Land and environment.
- Stakeholder and community engagement.
- Procurement costs.
- Insurance.

AVP intends to further refine costs for credible options as the RIT-T progresses, and plans to develop class 5A (+/-30% accuracy) estimates for the PADR using AEMO's latest TCD[42].

[42] Transmission Cost Database version 4-0, March 2023.

5.4 Estimation of market benefits

Section 4.1 explains that AVP expects the options to have some impact on NEM dispatch, and will consider the need to undertake wholesale market modelling in preparing the PADR, in view of both the network and non-network options that are being considered.

AVP will investigate whether wholesale electricity market modelling using market simulation software, such as PLEXOS, or an alternative method of estimating benefits from changes in NEM dispatch, is likely to be prudent and proportionate for the PADR. The proportionality assessment will consider the scale, size and potential benefits of credible options, and the extent to which wholesale market benefits are likely to affect either the ranking of the options or whether the options have a positive net market benefit. If a full wholesale market modelling exercise is not deemed necessary, AVP will likely apply a proportionate approach to estimating these benefits, which may include alternative methods of estimating the likely wholesale market benefits.

Changes in unserved energy is expected to be a key source of benefits for the options, so the sensitivity of the NPV results to the demand forecast adopted, and hence the EUSE, will be tested as part of this RIT-T.

5.5 Value of customer reliability

AVP intends to value avoided EUSE for the PADR assessment using the AER's most recent customer load-weighted state VCR for Victoria of $35,780 per MWh. The AER releases annual updates to its VCRs with the latest being published in December 2024[43]. AVP aims to use the latest information available for the PADR assessment and will therefore incorporate the VCR update from the AER's December 2024 publication.

5.6 Reasonable scenarios

AVP intends to use the ISP scenarios and associated weightings if it determines that wholesale market modelling is necessary for this RIT-T (see Section 5.4).

However, if modelling each ISP scenario is determined to be disproportionate to scale, size and potential benefits of the credible options, AVP will adopt reasonable scenarios that vary based on the demand forecast. This may involve the demand breakdown set out in Table 12.

[43] At https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2024/final-report.

Table 12 Proposed parameters for scenarios in RIT-T assessment

Parameter	Low	Central	High
Weighting	30.4%	39.2%	30.4%
Demand forecast	Zero EUSE is assumed for low demand conditions	50% POE	10% POE
ISP scenario	*Step Change*		
Discount rate	7%		
VCR	$35,780/MWh		
Network capital cost	Base estimate		
Operating and maintenance costs	Base estimate		

Initial analysis has determined that the risk of EUSE in the western metropolitan Melbourne network under 90% POE demand conditions is very low and the work required to model this scenario would be disproportionate to the potential benefits. Therefore, AVP intends to limit the studies to 10% POE and 50% POE demand forecasts only and assume the EUSE under 90% POE demand conditions is zero.

AVP intends to align weightings for EUSE with the AEMO August 2023 ESOO and Reliability Forecasting Methodology which designates weightings for 10% POE, 50% POE, and 90% POE of 30.4%, 39.2%, and 30.4% respectively as an appropriate approximation across the different years[44]. The intended approach is as follows:

- Determine EUSE in each financial year for both 10% POE and 50% POE demand conditions.
- Assume the EUSE is zero in the 90% POE case.
- Weight the average EUSE across the three POE cases and multiply the EUSE by VCR to determine the expected EUSE value.

If multiple ISP scenarios are modelled, these will have weightings aligned to the ISP scenario weighting of 43% for *Step Change*, 42% for the similar *Progressive Change* and 15% for *Green Energy Exports*.

AVP intends to conduct sensitivity analysis to test the sensitivity of the results to the following parameters:

- Discount rate (see Section 5.2).
- Capital costs (+/- 30 per cent, in line with the expected accuracy of the costs at the PADR stage (that is, class 5A)).
- VCR +/- 30%.

AVP will review its approach to reasonable scenarios and sensitivities ahead of the PADR, taking into account any stakeholder responses to this PSCR, and provided an updated assessment approach as part of the PADR.

[44] See Section 5.2.2, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

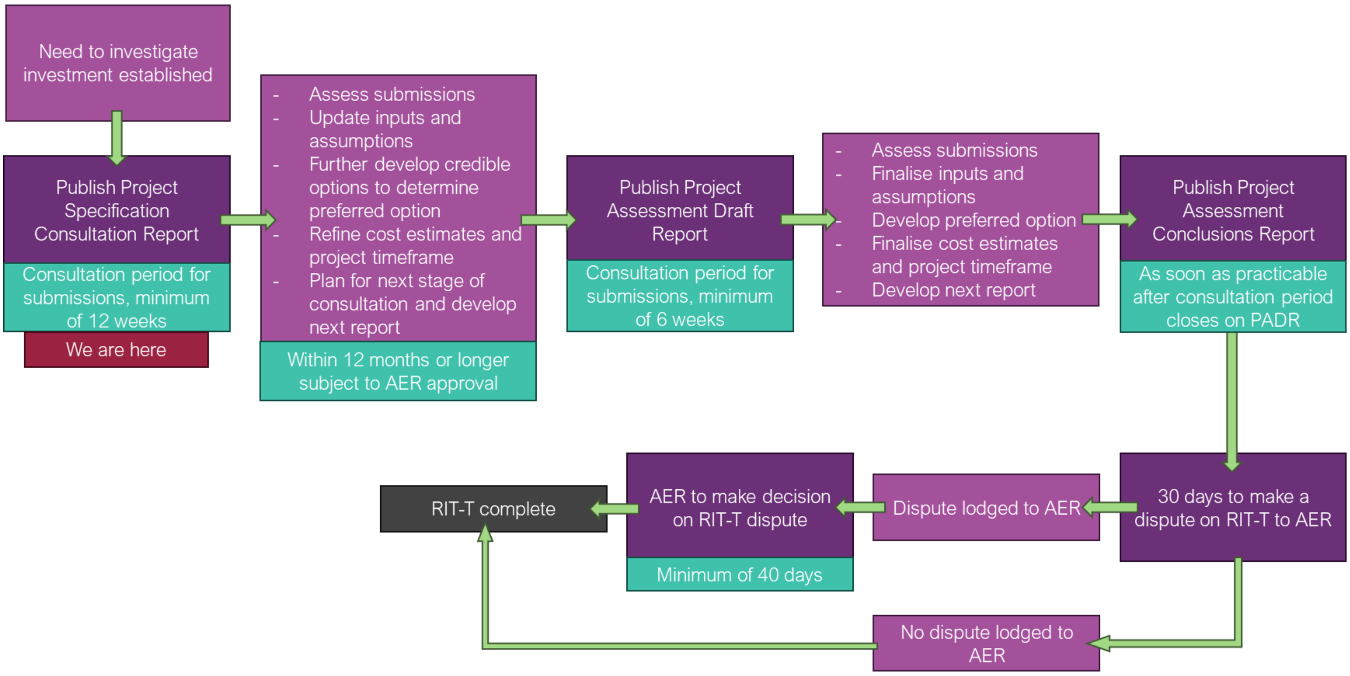
6 Next steps

AVP welcomes written submissions on this PSCR, particularly in relation to non-network options, to be provided to AVP_RIT-T@aemo.com.au, with subject title 'Western Metropolitan Melbourne Reinforcement PSCR', by 5.00 pm 6th June 2025.

Following conclusion of the PSCR consultation process, all submissions received will be published on AEMO's website. If you do not wish for your submission to be made public, please clearly stipulate this at the time of lodgement.

All feedback will be considered in preparing the PADR. AVP strongly encourages all interested non-network proponents to make submissions to the PSCR to ensure that a comprehensive suite of options is considered in the PADR to meet the identified need.

Figure 9 RIT-T progress and engagement opportunities



A1. Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PSCR with the requirements of the NER version 224.

Rules clause	Summary of requirements	Relevant section(s) in the PSCR
5.16.4(b)	A RIT-T proponent must prepare a PSCR, which must include:	
	(1) a description of the identified need;	2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2.3
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile;	3.3
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	NA
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	3
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	3.2, 3.4 and 4
5.16.4(f)	The RIT-T proponent must seek submissions from Registered Participants, AEMO and interested parties on the credible options presented, and the issues addressed, in the project specification consultation report.	6
5.16.4(g)	The period for consultation referred to in paragraph (f) must be not less than 12 weeks from the date that AEMO publishes the summary of the project specification consultation report on its website.	6

In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Guidelines section	Summary of the requirements	Relevant section(s) in the PSCR
3.5A.1	Where the estimated capital costs of the preferred option exceeds $100 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application:	5.3

Guidelines section	Summary of the requirements	Relevant section(s) in the PSCR
	• outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T • for all credible options (including the preferred option), either – apply the cost estimate classification system published by the AACE, or – if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.	
3.5A.2	For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied • the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance	5.3
3.5.3	A RIT-T proponent should consider the expected level of costs for building social licence. Where such costs are included in the RIT-T, they should be derived in a reasonable manner across all options. The RIT-T proponent is required to provide the basis for any social licence costs in its RIT-T reports, and may choose to refer to best practice from a reputable, independent and verifiable source.	N/A
3.9.4	If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and • how the level or quantum of the contingency allowance was determined.	3.2
4.1	RIT-T proponents are required to describe in each RIT-T report: • their assessment of the requirement for community engagement, including reasons for that assessment, and • as applicable – how they have engaged with community stakeholders and sought to address any relevant concerns identified through this engagement – how they plan to engage with these stakeholder groups	3.5