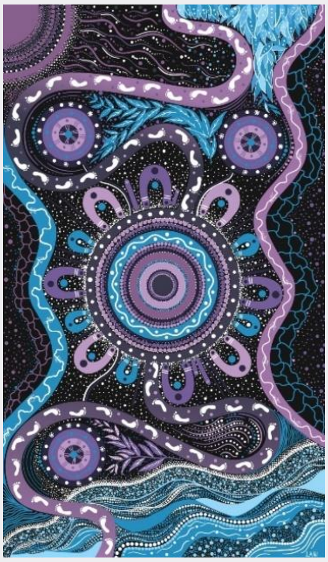
Melbourne Metropolitan Voltage Management – Project Assessment Conclusions Report

16 December 2024

Regulatory Investment Test for Transmission – Victoria



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

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AEMO publishes this Project Assessment Conclusion Report (PACR) in accordance with clause 5.16.4 of the National Electricity Rules. This publication is generally based on information available to AEMO as at 30 June 2024 unless otherwise indicated.

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Executive summary

Introduction

Investment is required to maintain Victorian Declared Shared Network (DSN) voltages in the metropolitan Melbourne region within operational and design limits, during both maximum and minimum operational demand periods, in a more efficient and cost-effective manner.

This investment need comes as a result of the forecast evolution of the DSN, which notably includes:

- A progressive increase in maximum demand.
- A progressive decrease in minimum demand.
- The retirement of aging capacitors (that currently provide generating reactive power support during high demand periods).
- The withdrawal of coal-fired generation.

These forecast changes in the DSN and the east coast's broader power system are resulting in a need for voltage management support in the metropolitan Melbourne area of Victoria such that voltages are maintained above lower limits during high demand periods and below upper limits during low demand periods.

The **identified need** of this Regulatory Investment Test for Transmission (RIT-T) is therefore comprised of two parts (or pillars):

- **Identified Need Pillar 1 – the need to manage under-voltages:** the need to maintain the power system in a satisfactory and secure operating state in metropolitan Melbourne by maintaining transmission system voltages within operational and design limits, and to maintain sufficient reactive power margins, during high demand periods when voltages are at risk of falling below limits or becoming unstable.
- **Identified Need Pillar 2 – the need to manage over-voltages:** the need to maintain the power system in a satisfactory and secure operating state by maintaining transmission system voltages within operational and design limits, in metropolitan Melbourne during low demand periods when voltages are at risk of rising above limits.

This RIT-T has involved publication of and consultation on three reports, including:

- The Project Specification Consultation Report (PSCR), which was published in October 2023 and sought feedback on the identified need and credible options to address that need.
- The Project Assessment Draft Report (PADR), which was published in July 2024 and considered feedback on the PSCR and identified and sought feedback on the RIT-T analysis and on selection of a proposed Preferred Option that delivers the highest net market benefits.
- This Project Assessment Conclusions Report (PACR), which considers feedback on the PADR, presents the final RIT-T analysis and makes a conclusion on the Preferred Option.

Scenarios and sensitivities analysed

The RIT-T requires cost-benefit analysis that considers reasonable scenarios of future supply and demand where each credible option is implemented and compared against where no option is implemented. Except for specific circumstances, RIT-T proponents must adopt the inputs, assumptions and scenarios from AEMO's most recent *Inputs, Assumptions and Scenarios Report* (IASR).

This RIT-T considers three reasonable future scenarios from the 2023 IASR: *Step Change, Progressive Change,* and *Green Energy Exports*.

This RIT-T also considers demand forecasts from the 2023 *Electricity Statement of Opportunities* (ESOO) in its cost-benefit assessment results, and provides a qualitative assessment of the impact of changing demand forecasts between the 2023 ESOO and the 2024 ESOO that was published in August 2024:

- For Identified Need Pillar 1 – maximum operational demand forecasts have decreased in the latter half of the 10-year forecasting horizon. If they eventuate, these updated demand forecasts could reduce or delay the need for investment in capacitors in later years and AVP has therefore identified future potential change impacts and material change triggers that will be monitored prior to procurement commencing.
- For Identified Need Pillar 2 – minimum operational demand forecasts are largely similar for 2024-25 to 2026-27, with more notable differences from 2027-28. This coincides with years where minimum operational demand forecasts are negative, where the magnitude of the identified need remains fixed for varying levels of negative operational demand. While the new forecasts would not increase the size of investment required, they would result in an increase in market benefits due to lower demand forecasts inherently resulting in more periods where voltage management support is needed. While this is the case, AVP has not performed an updated cost-benefit assessment considering these new forecasts given:
  - These new forecasts would not result in a change in ranking of options, nor would they change the Preferred Option.
  - AVP has identified that procurement activities for Stage 1 Pillar 2 investment should commence immediately after this RIT-T to deliver investment by 2028-29, hence identifying a need for investment sooner than 2028-29 is unlikely to result in earlier delivery of Stage 1 of the Preferred Option.

Market benefits

The classes of market benefits quantified in this RIT-T are:

- Changes in voluntary/involuntary load curtailment.
- Changes in emissions arising from changes in load curtailment.
- Changes in fuel consumption arising through different patterns of generation dispatch.
- Changes in costs for parties, other than for AVP, due to differences in the operational and maintenance costs of different plant.
- Changes in emissions arising through different patterns of generation dispatch.

The net market benefits for each credible option assessed in this PACR consider these market benefit classes and have been weighted across the three reasonable scenarios considered.

Credible Options Assessed

This PACR considered four credible options, as summarised in Table 1, that are considered capable of meeting the identified need.

The four options assessed are the same as those assessed in the PADR, albeit with refinement of the terminal station sites for the Stage 1 reactors which were revised following further joint planning with AusNet Services to determine the most economically and technically feasible location of assets to meet the identified need.

The assessment found Option 1 to have the highest weighted net market benefits under the assessed scenarios by more than $10 million compared with the option that yields the second highest net market benefits (Option 4).

Table 1 PACR options and weighted assessment outcomes

Option	Description	Total network MVAr invested	Capital cost ($M)	Combined pillars weighted gross market benefit in NPV ($M)	Combined pillars weighted net market benefit in NPV ($M)
Option 1 (Preferred)	Capacitors and reactors	600	47.5	285.9	255.1
Option 2	Capacitors and reactors, and non-network service in eastern metropolitan Melbourne	500 + confidential MVAr support	40.8 + confidential cost	284.1	Confidential[A] (but less than the net market benefits of Option 1)
Option 3	Capacitors and reactors, and non-network option at Deer Park	400 + confidential MVAr support	313.7	284.0	68.9
Option 4	Option 1 with one capacitor and one reactor displaced by one SVC in 2029	450	59.7	286.8	244.4

A. Costs are based on information for an eastern metropolitan Melbourne BESS provided on a confidential basis and therefore the net market benefits that use these costs as an input are also confidential.

Non-network options proposed in PADR submissions

AVP has qualitatively assessed non-network option submissions to the PADR, comparing them where appropriate with similar submissions to the PSCR which were assessed in detail in the PADR cost-benefit assessment. Based on the outcomes of this qualitative assessment, non-network options proposed would not economically displace the reactors and capacitors included in Option 1 (the Preferred Option).

Preferred Option

The Preferred Option that addresses both pillars of the identified need and maximises net market benefits for consumers is Option 1, which comprises:

- Stage 1, in 2028-29, to address Pillar 2 needs:
  - 2 x 100 MVAr shunt reactors at Altona 220 kV.
  - 1 x 100 MVAr shunt reactor at Brooklyn 220 kV.
- Stage 2, in 2030-31, to address Pillar 1 needs in western metropolitan Melbourne (namely Deer Park Terminal Station):

  - 1 x 100 MVAr shunt capacitor at Deer Park 220 kV.
- Stage 3, in 2033-34, to address Pillar 1 needs in metropolitan Melbourne more generally:
  - 1 x 100 MVAr shunt capacitor at Malvern 220 kV.
  - 1 x 100 MVAr shunt capacitor at Tyabb 220 kV.

This option is estimated to have a capital cost of $47.5 million, with a 1% of capital annual operating and maintenance cost, and is estimated to deliver $285.9 million in gross market benefits and $255.1 million in net market benefits on a net present value basis.

The Preferred Option comprises three stages of delivery. Procurement of Stage 1 needs to commence immediately after completion of this RIT-T for assets to be delivered by 2028-29 when the investment is needed. Procurement of Stage 2 is expected to commence by July 2027 and procurement of Stage 3 is expected to commence by July 2030. However, supply, demand, and network developments (as detailed in Section 2.5) that may erode the market benefits of stages 2 and 3 and defer the need for investment will be monitored and AVP will adjust course for Stage 2 and Stage 3 as needed.

Table 2 is an indicative timeline of activities from completion of this RIT-T to the delivery of all stages of the Preferred Option, considering a 30-month lead time for 220 kV shunt reactors and a 24-month lead time for 220 kV shunt capacitors, for asset delivery. AVP notes that asset delivery times are subject to change due to future supply chain uncertainty, as well as any project approval, land and environmental constraints not yet understood. AVP will continue to monitor these areas and procurement and delivery timelines will be updated and optimised where required.

Table 2 Indicative procurement and delivery timeline

Activity	Timeline	Duration
PACR published and RIT-T completed	December 2024	
RIT-T dispute period	16 December 2024 – 14 January 2025	30 days
Stage 1 – 3 x reactors delivered by 2028-29:		
• Procurement	January 2025 – January 2026	12 months
• Asset delivery	January 2026 – July 2028	30 months
• Stage 1 delivered	July 2028 (start of FY 2028-29)	
Stage 2 – 1 x capacitor at Deer Park delivered by 2030-31:		
• Monitor supply, demand, and network developments since completion of the RIT-T before commencing procurement.	January 2025 – July 2027 (or until start of procurement)	NA
• Procurement	July 2027 – July 2028	12 months
• Asset delivery	July 2028 – July 2030	24 months
• Stage 2 delivered	July 2030 (start of FY 2030-31)	
Stage 3 – 2 x capacitors delivered by 2033-34:		
• Monitor supply, demand, and network developments since completion of the RIT-T before commencing procurement.	January 2025 – July 2030 (or until start of procurement)	NA
• Procurement	July 2030 – July 2031	12 months
• Asset delivery	July 2031 – July 2033	24 months

Activity	Timeline	Duration
• **Stage 3 delivered (marks completion of delivery of the Preferred Option)**	July 2033 (start of FY 2033-34)	

Next steps

Following conclusion of the RIT-T dispute period which, assuming no dispute is lodged concludes 30 days after publication of this PACR, AVP will commence procurement activities in line with the requirements of the National Electricity Law and National Electricity Rules (NER). AVP will keep stakeholders informed through project updates during the procurement and implementation activities.

Contents

Executive summary		3
1	Introduction	10
1.1	Background to the RIT-T process	10
1.2	Overview of this RIT-T	11
1.3	Identified need	12
2	Methodology and future considerations	14
2.1	Overview	14
2.2	Assumptions	14
2.3	Modelling methodologies	17
2.4	Joint planning and submissions to the PADR	22
2.5	Potential future impacts and material change triggers	22
3	Net market benefit assessment	27
3.1	Classes of market benefits not expected to be material	27
3.2	Quantification of classes of material market benefit for each credible option	28
3.3	The 'do nothing' base case	29
3.4	Credible options assessed	33
3.5	Material inter-network impact	37
3.6	PACR updates to options	37
3.7	Preferred option	39
4	Conclusion and next steps	42
A1.	Checklist of compliance clauses	43

Tables

Table 1	PACR options and weighted assessment outcomes	5
Table 2	Indicative procurement and delivery timeline	6
Table 3	Pillar 1 – possible under-voltages for 2023 *Electricity Statement of Opportunities* (ESOO) Central scenario, 10% POE maximum demand forecast in the next 10 years	12

Table 4	Pillar 2 – possible over-voltages under 2023 ESOO Central scenario, 90% probability of exceedance (POE) minimum demand forecast in the next 10 years (assuming all transmission lines in service)	13
Table 5	Assumptions used in quantifying the identified need	14
Table 6	Assumptions used in quantifying the market benefits	15
Table 7	Possible triggers to a change in investment needs	23
Table 8	'Do nothing' involuntary load curtailment costs ($M)	30
Table 9	'Do nothing' emissions costs ($M)	30
Table 10	'Do nothing' out-of-merit-order annual dispatch costs ($M)	32
Table 11	'Do nothing' emissions costs ($M)	33
Table 12	'Do nothing' total underlying costs ($M)	33
Table 13	PACR options and weighted assessment outcomes	33
Table 14	Option 1 Net Market Benefits delivered in addressing the identified need ($M)	35
Table 15	Option 3 net market benefits delivered in addressing the identified need ($M)	36
Table 16	Option 4 net market benefits delivered in addressing Pillars 1 and 2 of the identified need ($M)	37
Table 17	Sites for new reactors and capacitors	38
Table 18	Cost estimates of individual assets	38
Table 19	Indicative procurement and delivery timeline	40
Table 20	Checklist of compliance clauses	43

Figures

Figure 1	Comparison of 2023 ESOO and 2024 ESOO Central, POE10 maximum operational demand forecasts for Victoria	25
Figure 2	Comparison of 2023 ESOO and 2024 ESOO Central, POE90 minimum operational demand forecasts for Victoria	26
Figure 3	'Do nothing' maximum supportable demand at the critical site Deer Park 220 kV	31
Figure 4	'Do nothing' maximum supportable demand at the critical site Tyabb 220 kV[A]	31
Figure 5	'Do nothing' maximum supportable demand at the critical site Rowville 220 kV[A]	31
Figure 6	Annual gross benefits, investment cost and net market benefits of Option 1 the Preferred Option ($M)	40

1 Introduction

The Regulatory Investment Test for Transmission (RIT-T) is an economic cost-benefit test used to assess and rank different investment options that address an identified need. This Project Assessment Conclusions Report (PACR) is the third and final stage of the consultation process in relation to this Metropolitan Melbourne Voltage Management RIT-T, which identifies the Preferred Option to manage under-voltages and over-voltages on the Victorian Declared Shared Network (DSN) in the metropolitan Melbourne area.

1.1 Background to the RIT-T process

Under the National Electricity Law, AEMO Victorian Planning (AVP) is responsible for planning and directing augmentation on the Victorian electricity transmission DSN. In deciding whether a proposed augmentation to the DSN should proceed, AVP is required to undertake a cost-benefit analysis using a probabilistic approach – in this case the RIT-T – to determine the benefit of an augmentation. The purpose of a RIT-T is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume, and transport electricity in the National Electricity Market (NEM).

This RIT-T has not been triggered through the *Integrated System Plan* (ISP) investment framework, and the project is not an actionable ISP project. The RIT-T process for projects that are not actionable ISP projects involves the publication of three reports, with consultation:

- The Project Specification Consultation Report (PSCR), which seeks feedback on the identified need and credible options to address that need.
- The Project Assessment Draft Report (PADR), which considers feedback on the PSCR and identifies and seeks feedback on the RIT-T analysis and on the selection of a Proposed Preferred Option that delivers the highest net market benefits.
- The Project Assessment Conclusions Report (PACR), which considers feedback on the PADR, presents the final RIT-T analysis and makes a conclusion on the Preferred Option.

The procedures for conducting a RIT-T are provided in clause 5.16.4 of the National Electricity Rules (NER), the Australian Energy Regulator's (AER's) RIT-T[1], and the RIT-T application guidelines[2].

[1] At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

[2] See https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf.

1.2 Overview of this RIT-T

In October 2023, AVP published the PSCR, the first stage of the RIT-T process, which:

- Identified the need for investment.
- Identified credible network options and the requirements for non-network options to meet this need.
- Identified classes of market benefits by which investment could be justified.
- Sought feedback and information from stakeholders on the identified need, the identified credible options, and potential non-network solutions capable of meeting the need.

In July 2024, AVP published the PADR, the second stage of the RIT-T process, which:

- Provided an update to the quantum and location of the identified need based primarily on additional anticipated and committed generator connections.
- Provided the methodology by which credible options were assessed.
- Provided the results of this assessment, including a ranking of credible options and the proposed Preferred Option.
- Assessed two non-network options provided in confidential submissions in response to the PSCR.
- Sought additional feedback to be considered for the third and final stage of the RIT-T process.

This PACR represents stage three of the RIT-T process, and provides:

- A confirmation of the identified need for investment described in previous reports (Section 1.3).
- A description of methodologies and assumptions (Sections 2.2 and 2.3).
- A description of joint planning on the RIT-T and submissions to the PADR (Section 2.4).
- A description of possible future impacts and material change triggers to this RIT-T (Section 2.5)
- A description of classes of market benefit not expected to be material, and the quantification of classes of market benefit that are considered material (Sections 3.1 and 3.2)
- A summary of the costs incurred in the 'do nothing' base case (Section 3.3)
- A summary of credible options assessed and their respective benefits (Section 3.4).
- A note on material inter-network impact (Section 3.5).
- A description of updates to the credible options since the PADR (Section 3.6).
- The final Preferred Option of this RIT-T (Section 3.7).
- Conclusion and next steps (Section 4).

1.3 Identified need

The identified need for investment is to maintain transmission system voltages in the metropolitan Melbourne region within operational and design limits and to meet system and network performance standards required of a network service provider (NSP)[3], during both high demand and low demand periods.

The identified need is captured in the following two pillars:

- **Identified Need Pillar 1 – the need to manage under-voltages:** the need to maintain the power system in a satisfactory and secure operating state[4] in metropolitan Melbourne by maintaining transmission system voltages within operational and design limits, and to maintain sufficient reactive power margins[3], during high demand periods when voltages are at risk of falling below limits or becoming unstable.
- **Identified Need Pillar 2 – the need to manage over-voltages:** the need to maintain the power system in a satisfactory and secure operating state[4] by maintaining transmission system voltages within operational and design limits, in metropolitan Melbourne during low demand periods when voltages are at risk of rising above limits.

As detailed in Section 2 of the PADR[5], the key drivers of the identified need are:

- For the first pillar, increasing operational demand levels during high demand periods in the general metropolitan Melbourne area, coupled with the retirement of synchronous generation in the Latrobe Valley in 2028, and the retirement of 650 megavolt amperes reactive (MVAr) of reactive support from capacitor banks in metropolitan Melbourne in 2027-28.
- For the second pillar, decreasing operational demand levels during low operational demand periods in the general metropolitan Melbourne area, coupled with fewer generators capable of absorbing reactive power being online as consumer energy resources (CER) such as distributed photovoltaic (PV) generators and batteries increasingly displace grid-scale generators.

Table 3 and Table 4 show the minimum and maximum forecast voltage levels if no action was taken to manage under-voltages and over-voltages within limits.

Table 3 Pillar 1 – possible under-voltages for 2023 *Electricity Statement of Opportunities* (ESOO) Central scenario, 10% POE maximum demand forecast in the next 10 years

Critical site	Low voltage limit (kilovolts (kV))	Possible post-contingent voltage level (kV) in next 10 years					
		2024-25	2025-26	2026-27	2027-28	2028-29	2033-34
Deer Park 220 kV	209	Within limits	Within limits	Within limits	Within limits	209	194
Tyabb 220 kV	209	Within limits	Within limits	Within limits	Within limits	Within limits	209
Rowville 220 kV area[A]	210	Within limits	Within limits	Within limits	Within limits	Within limits	204

A. This encompasses Rowville and Thomastown on the 220 kV level, with worst-case voltage levels for this area shown for Rowville 220 kV.

[3] Refer to Chapter Schedule 5.1 for network performance requirements to be provided by an NSP, including system stability.

[4] Refer to Chapter 4 of the NER for definitions of a satisfactory or secure operating state.

[5] At https://aemo.com.au/-/media/files/initiatives/metropolitan-melbourne-voltage-management-rit/melbourne-metropolitan-voltage-management-project-assessment-draft-report.pdf?la=en.

Table 4 Pillar 2 – possible over-voltages under 2023 ESOO Central scenario, 90% probability of exceedance (POE) minimum demand forecast in the next 10 years (assuming all transmission lines in service)

Critical site	System condition	High voltage limit (kV)[A]	Possible over-voltage level (kV) in next 10 years					
			2024-25	2025-26 [B]	2026-27	2027-28	2028-29	2033-34
South Morang 500 kV	System normal	525	525	Nil	Nil	526	530	530
Keilor 500 kV	System normal	525	Nil	Nil	Nil	Nil	526	526
Sydenham 500 kV	System normal	525	Nil	Nil	Nil	Nil	526	526
East metropolitan area 220 kV[C]	Post-contingency	228	Nil	Nil	Nil	Nil	229	229

A. For the respective system condition shown.
B. Over-voltage is forecast to reduce from 2024-25 to 2025-26 due to Melbourne Renewable Energy Hub being commissioned in 2025-26.
C. Includes sites such as Templestowe, Heatherton, Springvale, Malvern, Rowville, Ringwood, Richmond, Yallourn, Thomastown, East Rowville, and Tyabb. The 228 kV high voltage limit is the most onerous limit for this group. Some sites in this group have a higher limit.

While the quanta and locations of the identified need have not changed compared to those presented in the PADR, Chapter 2 of this PACR presents a qualitative assessment of inputs and assumptions that have evolved since the PADR, and those that have potential to evolve prior to AVP commencing procurement of Stage 2 and Stage 3 of the Preferred Option.

2 Methodology and future considerations

The methodology and inputs and assumptions used in assessing the market benefits outlined in this PACR are consistent with the PADR and based on AEMO's most recently published *Inputs, Assumptions and Scenarios Report* (IASR) with system and planning developments since PADR publication considered where appropriate. However, with a rapidly changing energy system, some future developments are unpredictable and could result in material changes to the investment need. AVP will monitor for such changes and consider their materiality to the investment need and timing prior to commencing procurement of Stage 2 and Stage 3 of the Preferred Option.

2.1 Overview

Consistent with the requirements of the AER's RIT-T guidelines[6], AVP has adopted the inputs, assumptions and scenarios from the most recent 2023 IASR (the same IASR adopted for the PADR). The PADR adopted inputs, assumptions and scenarios from the Draft 2024 ISP and its accompanying 2024 ISP Inputs and Assumptions workbook. The final 2024 ISP and its accompanying 2024 ISP Inputs and Assumptions Workbook were published shortly before the PADR publication and not incorporated in the PADR assessment. However, the changes between these IASR versions are not material to the outcomes of this RIT-T and the inputs, assumptions and scenarios adopted for this PACR are therefore consistent with the PADR. This section describes these key inputs, assumptions and scenarios, summarises the assessment methodology and outlines potential future impacts that could trigger a material change.

2.2 Assumptions

Consistent with Section 2.2 of the PADR, Table 5 summarises key inputs and assumptions used to quantify the identified need.

Table 5 Assumptions used in quantifying the identified need

Assumption category	Assumption description
System standards and voltage limitations	System voltages are maintained within site-specific limitations where specified (in AEMO operational procedures) for system normal and post-credible contingency conditions. Where not available, system voltages adhere to NER standards specified in NER S5.1.4 and S5.1a.4. That is, system voltages: • Are maintained within +/-10% of normal voltages for system normal conditions. • As a consequence of a credible contingency event: – Do not rise above normal voltages by more than a given percentage of normal voltage for longer than the corresponding period as shown in NER Figure S5.1a.1. – Are allowed to fall to zero for any period of time.

[6] See https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf.

Assumption category	Assumption description
Transmission connection point demand forecasts	For maximum demand studies, AVP continues to use 2023 coincident connection point maximum demand forecasts for Victoria (developed by AEMO and available in *Attachment A – Maximum Demand Connection Point Forecast* published as part of the PADR[A]) to distribute the 2023 ESOO regional maximum demand forecasts across connection points in the Victorian DSN, and to model the power factor for each connection point in the Victorian DSN. For minimum demand studies, the connection point load profile is based on the 2022-23 minimum demand day profile (13:00 on 18 December 2022), with Victorian regional demand scaled to match the 2023 ESOO regional minimum demand forecasts. A qualitative comparison of the 2023 ESOO and 2024 ESOO regional demand forecasts is discussed in Section 2.5.1.
Forecast of generation expansion and withdrawals	AVP incorporated committed and anticipated projects listed in the May 2024 Generation Information update, as well as generator withdrawals, in Victoria. The July 2024 Generation Information update released after the PADR resulted in no changes in the list of committed and anticipated connections, or generator withdrawals, that may materially affect the identified need or options to meet it.
Dispatch	Dispatch assumptions remain as described in Table 10 (Section 2.2.5) of the PADR, for maximum demand and minimum demand periods: • Grid-scale solar farms are offline for maximum demand and at 50% of maximum capacity for minimum demand. • Wind farms are online at 30% of maximum capacity for maximum demand and online with 0 MW output for minimum demand. • BESSs are online with 0 MW output at maximum demand and minimum demand. • Synchronous generators are online with MW output up to maximum rated capacity for maximum demand. For minimum demand, synchronous generators are online if able to be dispatched above their minimum stable level, and are otherwise offline.
Reactive power support from large-scale inverter-based resources	AVP is continuing to consider reactive power support availability from large inverter-based resources (IBR) in line with respective performance standards and dispatch levels noted above and in Table 10 (Section 2.2.5) of the PADR, where reactive power support is assumed available when generation has been assumed online, or unavailable when generation has been assumed offline. Reactive support has not been considered from future uncommitted generation and storage projects which are not yet guaranteed.
Reactive power support from distributed PV	AVP has assumed no reactive power support from distributed PV because the impact of volt-var response capability of distributed PV on the transmission level is under ongoing investigation but is currently not well known.

A. At https://aemo.com.au/initiatives/major-programs/metropolitan-melbourne-voltage-management-regulatory-investment-test-for-transmission.

Consistent with Section 5.2 of the PADR, Table 6 summarises the key inputs and assumptions used in quantifying the market benefits.

Table 6 Assumptions used in quantifying the market benefits

Assumption category	Assumption description	Information source
Analysis period	Analysis has been undertaken over a 10-year period from 2024-25 to 2033-34. To capture overall market benefits of a credible option with asset life extending past 2033-34: • For Identified Need Pillar 1 (need to manage under-voltages), the benefits associated with reducing involuntary load curtailment for the final (tenth) year have been extrapolated across the life of the asset on the basis that increases in maximum demand beyond this tenth year will be addressed through future planning exercises. • For Identified Need Pillar 2 (need to manage over-voltages), the changes in fuel, operating and maintenance, and emission costs calculated for the final three years of the modelling period relative to the counterfactual were averaged, and this average value was extrapolated across the life of the asset under that credible option.	AVP internal methodology
Asset life	• 20 years for capacitors. • 30 years for reactors.	• Industry knowledge for network options.

Assumption category	Assumption description	Information source
	• 30 years for dynamic plant such as a static VAR compensator (SVC). • For generator and battery energy storage system (BESS) non-network options, aligned with economic and technical life of new entrant generators included in the 2024 ISP Inputs and Assumptions workbook (for example, 20 years for new entrant battery storage).	• 2024 ISP Inputs and Assumptions workbook for non-network options.
Discount rate	7% base discount rate (real, pre-tax). 3% and 10.5% discount rate for sensitivity studies.	2023 IASR and 2024 ISP
Reasonable scenarios and weightings	Three ISP scenarios were assessed and weighted in accordance with the ISP weightings: *Step Change* (43%), *Progressive Change* (42%) and *Green Energy Exports* (15%)	2023 IASR and 2024 ISP Delphi Panel
Regional demand and distributed PV	Three probability-of-exceedance (POE) half-hourly demand profiles were assessed and weighted in accordance with the 2023 ESOO: POE10 (30.4%), POE50 (39.2%) and POE90 (30.4%)	2023 IASR (2023 ESOO)
Generator assumptions	• New generic generation and storage investment in line with outcomes for the different scenarios from the 2024 ISP, to meet future demand needs. • Renewable generator half-hourly output traces from the 2024 ISP to calculate renewable generator dispatch. • Generator fuel costs, emissions intensity, and variable and fixed operating and maintenance costs (OPEX) from the 2023 IASR. • Reduced requirements for Victorian system strength minimum generator combinations (for Pillar 2), on the basis that future system strength needs will be met separately through delivery of the preferred solution of the currently ongoing System Strength RIT-T. • Synchronous generator minimum output levels from the 2023 IASR. • Synchronous generator start-up times estimated based on operational experience. • Synchronous generator start-up fuel usage at 10% of fuel usage at full generator capacity.	• 2024 ISP • 2023 IASR • AEMO transfer limit advice for system strength
Transmission development	AVP considered all committed, anticipated, and actionable ISP projects impacting the Victorian region from AEMO's August 2024 NEM Transmission Augmentation Information Page and in line with the 2024 ISP. Additionally, AVP included the proposed Latrobe Valley network reconfiguration following retirement of Yallourn Power Station in 2028, consistent with the proposal presented in the 2024 VAPR and the 2024 ISP.	• AEMO NEM Transmission Augmentation Information Page • 2024 VAPR and 2024 ISP
Interconnector transfers during maximum demand conditions	For maximum demand power flow studies, the following interconnector transfers were assumed for existing, committed and actionable interconnector corridors during high demand periods: • Low imports (approximately 250 megawatts (MW)) from South Australia to Victoria via Heywood and Murraylink. • Low exports from South Australia/Victoria to New South Wales (approximately 250 MW) via Project EnergyConnect (from 2027-28, once fully commissioned) and Red Cliffs to Buronga corridor. • High imports from New South Wales to Victoria (approximately 500 MW) via Victoria – New South Wales Interconnector East (VNI East) corridor. High imports from New South Wales to Victoria (approximately 1,600 MW) via Victoria – New South Wales Interconnector West (VNI West) corridor and VNI East corridor (from 2029-30, once VNI West is fully in service). • High imports from Tasmania to Victoria (approximately 470 MW) via Basslink. High imports from Tasmania to Victoria (approximately 1,200 MW) via Basslink and Marinus link (from 2030-31 for Marinus Link Stage 1 and 2032-33 for Marinus Link Stage 2, once fully in service).	AVP internal assumption utilising historical data
Interconnector transfers during minimum demand conditions	For minimum demand power flow studies and the benefits assessment, the following interconnector transfers have been assumed for existing, committed and actionable interconnector corridors during low demand periods: • Close to zero flow across Victoria to South Australia via Heywood and Murraylink.	AVP internal assumption utilising historical data

Assumption category	Assumption description	Information source
	• Low exports from South Australia/Victoria to New South Wales (approximately 250 MW) via Project EnergyConnect (from years where it is commissioned) and Red Cliffs to Buronga corridor. • Medium exports from Victoria to New South Wales (approximately 800 MW) via VNI East corridor. • High exports from Victoria to Tasmania (approximately 470 MW) via Basslink.	
Cost estimate methodology	Cost estimates are class 5A (+/- 30%) and were developed for new plant using AEMO's latest Transmission Cost Database (TCD).	TCD for new plant.

2.2.1 Input and assumption changes since the PADR

Consistent with the requirements of the AER's RIT-T guidelines[7], AVP has adopted the inputs, assumptions and scenarios from the most recent 2023 IASR (the same IASR adopted for the PADR), except in circumstances where new, omitted, or varied inputs or assumptions have been necessary. Although the final 2024 ISP and its accompanying 2024 ISP Inputs and Assumptions Workbook was not considered in the PADR publication, it has been considered for this PACR, however the changes between these IASR versions are not material to the outcomes of this RIT-T and the inputs, assumptions and scenarios adopted for this PACR are therefore consistent with the PADR.

Below is an update on any changes in inputs and assumptions since the PADR for identifying and quantifying the need.

2.2.2 Operational measures

Since the PADR, the project to make the Keilor over-voltage scheme operationally available has been completed, and Keilor 500 kV now has a continuous high voltage limit of 525 kV and a short-term high voltage limit of 535 kV.

There have been no other changes since the PADR regarding operational measures considered for this RIT-T. See Section 2.2.8 of the PADR for the latest information on these.

2.3 Modelling methodologies

Consistent with the PADR, AVP used a combination of power system studies and analysis of ISP market development modelling to estimate the market benefits associated with each credible option.

2.3.1 Power system studies

Power system studies were undertaken with a PSS®E[8] model of the Victorian transmission network to determine the voltage exceedances under a range of scenarios for a 'do nothing' future, where no investment is made to meet the identified need, and to determine the requirements of credible options to manage voltages within operational and design limits and to meet system and network performance standards required of an NSP (such as minimum required reactive power margins).

[7] See https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf.

[8] Power System Simulator for Engineering, software developed by Siemens PTI.

Identified Need Pillar 1

For Identified Need Pillar 1, AVP undertook steady-state and Reactive Voltage (QV) stability power system studies focusing on high demand periods to identify individual transmission connection points or groups of individual connection points with low voltage limit exceedances and/or reactive margin shortfalls for a range of scenarios for a 'do nothing' future. Studies were also then undertaken to determine, for the transmission connection points at risk of voltage limit exceedance or reactive margin shortfall in future, the maximum supportable demand, up to the non-coincident maximum demand forecast from the AEMO connection point forecast for the respective transmission connection point or connection points group.

This maximum supportable demand was further revised to consider thermal limitations as well, to be the lesser of:

- The maximum supportable demand due to low voltage limits or voltage stability.
- The maximum supportable demand due to thermal limitations.

One such example is Deer Park 220 kilovolts (kV), which has thermal limitations on the local Deer Park – Keilor and Deer Park – Geelong 220 kV lines that can bind before Deer Park load can reach the maximum demand forecast in the AEMO connection point forecast, and before Deer Park low voltage limits or reactive margin limits are exceeded.

Studies were then also undertaken to determine the requirements of credible options to manage voltages within limits, and what the maximum supportable demand at each transmission connection point would be lifted to with these credible options in place.

These maximum supportable demand levels, for both a 'do nothing' case and for each credible option, were then used as inputs into the gross market benefit analysis.

Identified Need Pillar 2

For Identified Need Pillar 2, power system studies focusing on low demand periods were undertaken to identify transmission connection points with high voltage limit exceedances for a range of scenarios for a 'do nothing' future, and to determine the requirements of credible options to manage voltages within limits.

Studies were also undertaken to quantify the sensitivity of voltage exceedances and the equivalent reactive shortfall (for both a 'do nothing' case and for each credible option) against the following factors:

- Operational demand level.
- Number of coal units online (and subsequently the total megawatts (MW) and megavolt amperes reactive (MVAr) output provided by coal units).
- Critical contingencies.
- Location of credible options.

The outcomes of these studies were then used as inputs into the market benefit analysis.

2.3.2 Benefits assessment methodology

The market development modelling and time-sequential modelling outcomes from the 2024 ISP have been leveraged in assessing the gross market benefits under each scenario, with and without each credible option. This has avoided the need for separate detailed market modelling while still allowing for quantification of the relevant classes of market benefit. The following section outlines how changes in costs for each relevant market benefit class have been assessed.

2.3.3 Comparing states of the world with and without the credible option in place

Identified Need Pillar 1

Calculating changes in involuntary load curtailment

During high demand periods AEMO's system operators may need to intervene, or automatic schemes may need to be activated, to curtail load to maintain voltage stability and to manage voltages within operational and design limits.

To assess the magnitude and cost of involuntary load curtailment, the following steps were undertaken for each half-hour in the modelling period with and without the credible options in place:

- Step 1 – for each transmission connection point or connection point group with an identified maximum supportable demand, an estimate of the half-hour demand level was created based on historical patterns and AEMO's non-coincident maximum demand forecast for the relevant year for the connection point.
- Step 2 – if the connection point's demand is above the respective maximum supportable demand, curtail the amount of load needed to bring the connection point's demand back to the maximum supportable level.
- Step 3 – calculate the cost associated with load that is curtailed according to Steps 1 and 2 above using a pre-determined value of customer reliability.

Calculating changes in emissions

Involuntary load curtailment during high demand periods would result in the MW output of the highest-cost dispatched generation for these periods to also being run-back. Where this generation has some level of emissions intensity, this load curtailment would also then result in overall reduced emissions compared with a world where the load is not curtailed.

To assess the magnitude and benefit of emission reduction, the following steps were undertaken for each half-hour in the modelling period with and without the credible options in place:

- Step 1 – take the involuntary load curtailment for the half-hour calculated in the previous subsection.
- Step 2 – identify the highest cost dispatched generation (Victorian gas generators) for the period and its corresponding emissions intensity from the 2023 IASR.
- Step 3 – use the involuntary load curtailment and the emissions intensity to calculate total emissions reduction for the half-hour.
- Step 4 – calculate the cost of this using the value of emissions reduction (VER)[9] and the total emissions reduction identified in Step 3.

Gross market benefits

The annual gross market benefits of each credible option were calculated by comparing the costs of involuntary load curtailment and benefits of associated emissions reduction with and without the credible option in place. Pillar 1 credible

[9] In this PADR, AVP adopted the interim VER published by the AER at https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf.

options that reduce overall involuntary load curtailment compared with a 'do nothing' world will inversely result in higher overall emissions compared with that world.

Identified Need Pillar 2

During low demand periods, AEMO's system operators may need to intervene in the market to maintain voltages within operational and design limits. This intervention, which would occur via a direction in the absence of a non-market ancillary service (NMAS) contract, involves AEMO dispatching a generator online 'out-of-merit' order, or in other words running a more expensive generator than would be dispatched without the intervention.

To capture the market cost of this intervention, the following steps were undertaken for each half-hour in the modelling period with and without the credible options in place:

- Step 1 – calculate the reactive power shortfall using operational demand and renewable and thermal generation online as derived using generator assumptions from Table 6. For a non-zero reactive power shortfall, determine the number of additional generators (as described in the Representative generators sub-section below) required to be online to remove the reactive power shortfall, and subsequently the generation originally online that would be displaced by this additional generation (where renewables are displaced first and then thermal generation second).
- Step 2 – calculate the additional cost of starting-up and dispatching the additional generators brought online in Step 1 (including any change in emission costs).

Representative generators

Combinations of Victorian grid-connected gas generators that could deliver at least 100 MVAr absorbing reactive capability were developed to form a representative generator with average:

- Absorbing reactive capability.
- Minimum dispatch levels.
- Dispatch costs (fuel plus variable operating and maintenance costs).
- Start-up time.
- Start-up cost.

These representative generators were then dispatched as required to remove the reactive power shortfall.

Cost of dispatching representative generators

The cost of dispatching the representative generators was calculated using the following:

Dispatch cost ($) = (Generator start-up costs ($) + minimum generation (MWh) x *generator dispatch cost ($/MWh))* – *(minimum generation (MWh)* x *displaced generator cost ($/MWh))*.

The dispatch cost includes the fuel costs and the variable operating and maintenance costs.

Emission costs

The emissions benefits associated with Pillar 2 for each credible option are the benefits of not needing to dispatch emissions-intensive representative generators (which also provide voltage management support in the needed locations) that would otherwise be dispatched in a 'do nothing' world.

The emissions cost associated with dispatching the representative generators was calculated using the following:

Total emissions (kg) = minimum generation (megawatt hours (MWh)) x *representative generator emissions intensity (kg/MWh)*

Cost of emissions ($) = (total emissions of directed generation (kg) x *VER*[10] *($/kg)) – (total emissions of displaced generation (kg)* x *VER ($/kg))*

Gross market benefits

The annual gross market benefits of each credible option were calculated by comparing the costs of dispatching the representative generators and emissions reduction with the credible option in place with these costs in the 'do nothing' case (no credible options in place).

2.3.4 Emissions reduction objective and subsequent rule changes

In May 2023, Energy Ministers amended the National Electricity Objective (NEO) to incorporate an emissions reduction objective[11]. In turn, the Australian Energy Market Commission (AEMC) launched a rule change to harmonise the national energy rules with the updated NEO.

Transitional provisions in the *Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Act 2023* (Emissions Act), which received royal assent on 21 September 2023, clarified that the updated NEO applies to any RIT-T project that is required to publish a PADR where the deadline for doing so was after 21 November 2023.

The AEMC rule changes were finalised as of 1 February 2024, requiring RIT-T proponents to consider emissions reduction as a market benefit class.

AVP has considered emissions reduction as a class of benefit for Pillars 1 and 2 as discussed in Section 3.2.4.

AVP has not quantified the cost of emissions associated with the potential leakage of sulphur hexafluoride (SF6) – an inert insulating gas often used in transmission switchgear – from substation equipment. While these emissions are expected to marginally reduce the net market benefits of the credible options assessed, SF6 leakage is only expected from the circuit breakers connecting the credible options plant. Since all options will require a transmission connection circuit breaker the cost of emissions are expected to be in the same order for each credible option assessed and are marginal relative to other estimated costs and benefits. As such the inclusion or omission of emission costs from SF6 leakage is considered immaterial to the ranking, timing and size of options.

2.3.5 Investment timing methodology

The timing of the individual components in each of the credible options was developed by assessing when each individual component first delivers positive net benefits. Procurement lead times allowing, this was then set as the individual components' preferred timing.

[10] In this PADR, AVP adopted the interim VER published by the AER at https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf.

[11] See https://www.aer.gov.au/system/files/2023-09/AER%20-%20Guidance%20on%20amended%20National%20Energy%20Objectives%20-%20Final%20guidance%20note%20-%20September%202023.pdf.

Where the year that individual components first deliver positive net benefits is earlier than the earliest possible delivery date due to lead times, the timing is then set according to these procurement lead times instead.

For credible options with more than one component at the same terminal station, investments are generally timed together if the increase in net benefits from staging is less than $0.5 million, due to expected efficiencies in combining the components. This did not result in any changes to the timing of individual components for this PACR.

2.4 Joint planning and submissions to the PADR

2.4.1 Joint planning on aging assets and the preferred option

Consistent with the PADR, AVP has considered service agreements expiring within the next 10 years (that is, until 2033-34) – notably a reactive power services agreement relating to several capacitor banks in metropolitan Melbourne that expires in 2027-28. These capacitor banks have an aggregate generating reactive power capacity of 650 MVAr and will have reached end of technical life at that point[12].

AVP has undertaken joint planning with AusNet Services on the retirement of these capacitors in 2027-28, as well as on the preferred option to meet the Identified Need of this RIT-T which considers this retirement. Joint planning on the preferred option primarily involved input from AusNet Services on the feasibility of establishing new reactors, that constitute Stage 1 of the Preferred Option, and new capacitors, that constitute Stage 3 of the Preferred Option, within existing terminal station sites owned by AusNet Services.

This joint planning has resulted in an update to the locations identified for reactors included in the Preferred Option as detailed in Section 3.6.2.

2.4.2 Submissions to the PADR

The PADR (second stage of the RIT-T) was published in July 2024 and invited interested parties to make written submissions. AVP received four submissions in response to the PADR, all of which were confidential. While the detail of the submissions cannot be shared due to their confidential nature, the majority of these submissions involved non-network option proposals. Each of these were in similar locations, and of similar size, to the non-network options assessed in the PADR. As such, each of these options were considered to provide similar benefits to options assessed in the PADR and have not resulted in changes to the ranking of options or to the final Preferred Option.

Any submissions or submission components not directly relating to a non-network option proposal were discussed with the submitting party and have been considered in developing this PACR and determining the final Proposed Option of this RIT-T.

2.5 Potential future impacts and material change triggers

With a rapidly changing energy system, some future developments are unpredictable and could result in material changes to the investment need. These potential future developments that AVP considers could trigger a change in the investment needs are summarised in Table 7. These investment need change triggers build on the sensitivities explored in Section 6.5 of

[12] See Section 4.6.2 of the 2024 VAPR for more information on asset retirements across the Victorian Declared Shared Network (DSN).

the PADR (some that the Preferred Option was found to be robust against and some that were found to potentially have a material impact on the Preferred Option).

Given the lead time for asset delivery, procurement for Stage 1 of the Preferred Option will commence immediately after completion of this RIT-T and its dispute period to ensure the Stage 1 assets can be delivered when required. Therefore, while some of the below future developments may have an impact on the Stage 1 investment needs, certainty around their development will not occur until after procurement has commenced, and these are noted in this section for information only.

Some future developments may also have an impact on the Stage 2 and Stage 3 investment needs, for which procurement is not expected to commence until around July 2027 and July 2030 respectively. AVP will monitor these developments and consider their materiality to the Stage 2 and Stage 3 investment needs and timing prior to commencing procurement.

Table 7 Possible triggers to a change in investment needs

Sensitivity	Outcome
Sensitivities tested in the PADR	
Change in cost	Preferred Option is robust against changes in cost within ±30% of the costs outlined in this PACR.
Change in discount rate	Preferred Option is robust against discount rates ranging from 3% to 10.5%.
Impact of publicly announced projects	The size and timing of the Preferred Option is subject to additional connection projects becoming committed or anticipated. Progression of connection projects has the potential to defer components or decrease the size of the Preferred Option. While they may have an impact on all three stages of the Preferred Option, procurement of Stage 1 will need to commence prior to any development in this space.
Impact of ongoing system strength RIT-T	Procurement of services under AVP's system strength RIT-T has potential to defer components or decrease the size of the Preferred Option. Any impacts will be considered as the system strength RIT-T progresses. While outcomes of the system strength RIT-T may have an impact on all three stages of the Preferred Option, procurement of Stage 1 will need to commence prior to any development on the system strength RIT-T.
Impact of possible network upgrades due to thermal limitations between eastern and western metropolitan Melbourne and significant supply hubs in Victoria	Procurement of services under AVP's other RIT-Ts has potential to defer components or decrease the size of the Preferred Option. Any impacts to Stage 2 or Stage 3 of the Preferred Option will be considered as the other investment cases are progressed.
Other sensitivities	
Any notable changes to the post-YPS operating configuration that may alter power flows	AVP will monitor and revisit procurement requirements for Stage 2 and Stage 3 of the Preferred Option if any changes to the post-Yallourn retirement network reconfiguration occur, which could increase or bring forward investment need.
Changes in demand forecasts **(refer to section 2.5.12.5.1 for how changes in demand forecasts between the 2023 ESOO and the 2024 ESOO have impacted the need and timing for investment).**	An increase in maximum demand forecasts could increase and bring forward the investment need for Pillar 1. A decrease would do the opposite. Procurement of investment for Pillar 2 (Stage 1) needs to occur immediately after this RIT-T to meet the investment timing requirement. Therefore, any future changes in minimum demand forecasts will be addressed through a separate assessment to this RIT-T.
Change in general power system operations for negative demand levels	While periods with sustained negative demand levels are relatively uncharted territory, as the power system nears periods where we expect this, we expect to gain further insights to the typical operating behaviour of the power system generally as well as any demand, BESS, or generator responses to help manage such conditions. Any evolution on this would likely curb negative impacts on the system from negative demand. Given procurement of investment for Pillar 2 (Stage 1) needs to occur immediately after this RIT-T, any developments in this space will be assessed through a separate assessment.
Progression of understanding of distributed PV volt-var capability impact on transmission network	While the rate of compliance to AS/NZS4777.2:2020 requiring distributed PV to provide a volt-var response under certain conditions has increased considerably in recent years, the impact, at transmission network levels, of volt-var responses delivered at the 240 V residential level is currently

Sensitivity	Outcome
	not well known. AVP has undertaken a conservative approach for this RIT-T and assumed this volt-var response has no impact on the transmission network (same impact as assuming distributed PV does not provide volt-var responses from a transmission network point of view). AVP will continue to monitor progress in this space and will consider this impact on the transmission network in future, separate assessments when understood and quantifiable.

2.5.1 Changes in demand forecasts

The 2024 ESOO published new regional operational demand forecasts in August 2024. While AVP's assessment in this PACR of the preferred option is based on the 2023 ESOO demand forecasts, this section provides a qualitative assessment of the impact of changing demand forecasts. AVP will continue to monitor changes in demand forecasts and will assess the materiality of change prior to commencing procurement of Stage 2 and Stage 3 of the Preferred Option.

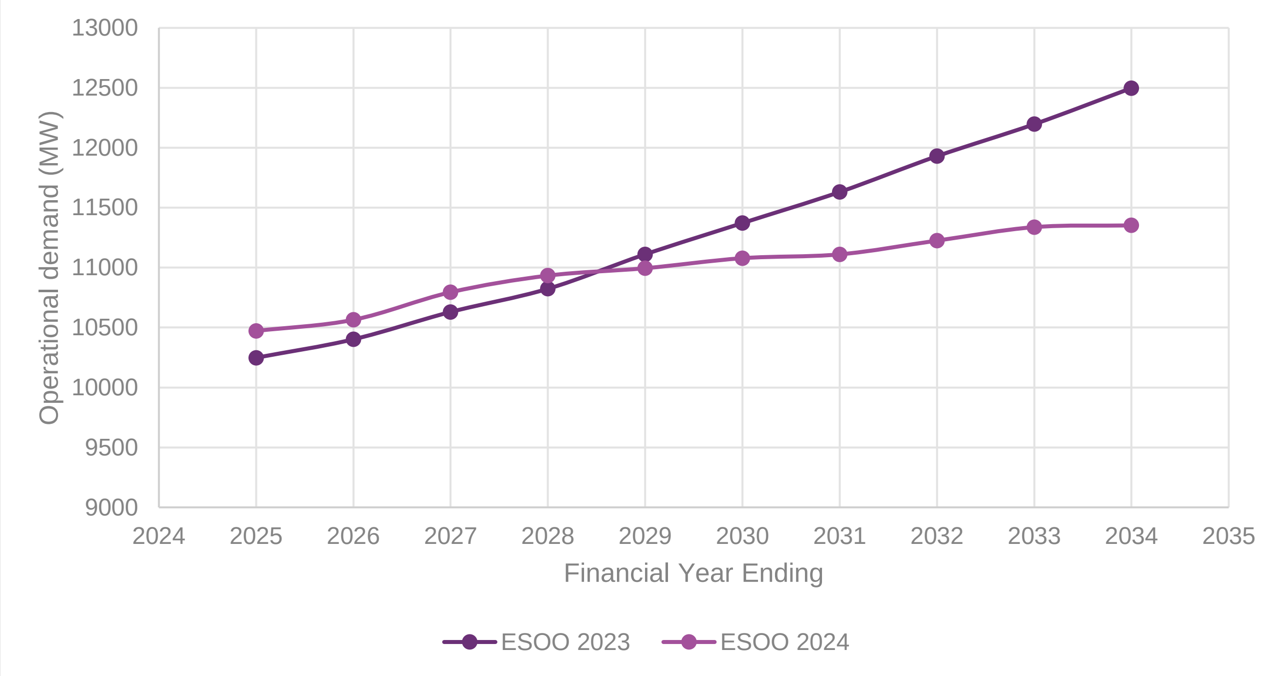
Regional maximum demand forecast

Figure 1 provides a comparison of the 2023 ESOO (used in assessing the Identified Need) and the 2024 ESOO (the latest ESOO) POE10, Central scenario maximum operational demand forecasts for Victoria.

This shows that demand forecasts have increased between 2024-25 and 2027-28, but have decreased between 2028-29 and 2033-34 (the end of the 10-year forecast horizon). Given that the PADR identified a need for voltage management support for Pillar 1 from 2028-29 onwards – when the regional demand forecast in the 2024 ESOO is comparatively lower – the new forecasts have potential to decrease or defer the need for investment in capacitors in the later years of the planning period assessed.

While the change in forecast demand between the 2023 ESOO and the 2024 ESOO somewhat reduces the identified need in later years, demand forecasts may change in future ESOOs and AVP has therefore not assessed in detail the impact of these forecast demand changes. AVP will instead monitor future demand forecast changes and consider the materiality of them closer to when procurement of any capacitor banks is expected to commence.

Figure 1 Comparison of 2023 ESOO and 2024 ESOO Central, POE10 maximum operational demand forecasts for Victoria



Regional minimum demand forecast

Figure 2 compares the 2023 ESOO (used in assessing the Identified Need) and the 2024 ESOO (the latest ESOO publication) POE90, Central scenario minimum operational demand forecasts for Victoria.

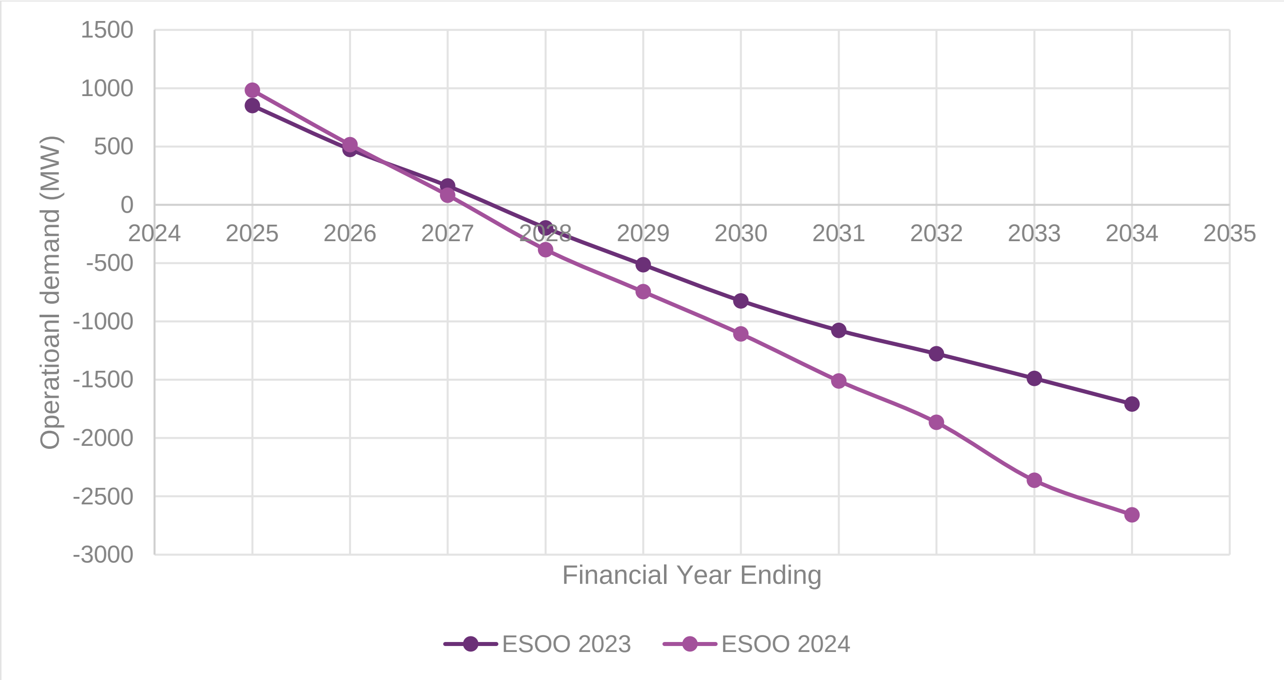
This shows that demand forecasts are largely similar for 2024-25 to 2026-27, with more notable differences from 2027-28. This coincides with years where minimum operational demand forecasts are negative and, as shown in Chapter 2 of the PADR, the identified need remains fixed at an equivalent absorbing MVAr capacity requirement of 215 MVAr at South Morang 500 kV for negative demand levels.

While the new forecasts would not increase the size of investment required, they would result in a change to the market benefits accrued with options due to lower demand forecasts inherently resulting in more periods where voltage management support is needed. A qualitative assessment of Figure 2 shows that the optimal timing of investment of Stage 1 Pillar 2 investment could be brought forward from 2028-29 to 2027-28 (where the 2024 ESOO minimum demand forecast for 2027-28 is at a similar level to the 2023 ESOO minimum demand forecast for 2028-29).

While this is the case, AVP has not performed an updated cost-benefit assessment considering these new forecasts given that:

- These new forecasts would not result in a change in ranking of options, nor would they change the Preferred Option.
- AVP has identified that procurement activities for Stage 1 Pillar 2 investment should commence immediately after this RIT-T to enable delivery of the Stage 1 investment by 2028-29; hence identifying a need for investment in 2027-28 is unlikely to result in any sooner option delivery.

Figure 2 Comparison of 2023 ESOO and 2024 ESOO Central, POE90 minimum operational demand forecasts for Victoria



3 Net market benefit assessment

AVP has assessed four credible options in this PACR.

The preferred option identified in this PACR is Option 1 and includes installing three 100 MVAr reactors on the 220 kV level, two at Altona Terminal Station and one at Brooklyn Terminal Station, by 2028-29, one 100 MVAr capacitor on the 220 kV level, at Deer Park Terminal Station, by 2030-31 and two 100 MVAr capacitors on the 220 kV level, one at Malvern Terminal Station and one at Tyabb Terminal Station, by 2033-34. The total capital cost of the preferred option is $47.5 million and is expected to deliver $255.1 million in net market benefits over the life of the assets.

The preferred option presented in this PACR differs slightly from the proposed preferred option presented in the PADR. In refining the preferred option, the terminal station sites for the Stage 1 reactors were revised following joint planning with AusNet Services to determine the most economically and technically feasible location of assets to meet the identified need.

3.1 Classes of market benefits not expected to be material

A class of market benefit is not expected to be material if:

- the class is likely not to affect materially the assessment outcome of the credible options for this RIT-T; or
- the estimated cost of undertaking the analysis to quantify market benefits of the class is likely to be disproportionate to the scale, size, and potential benefits of each credible option being considered.

AVP has identified that the following classes of market benefits are not expected to be material to this RIT-T (consistent with the PADR) include:

- **Some wholesale electricity market benefits** – the credible options considered in this PACR are intended to provide voltage support in the metropolitan Melbourne region of Victoria during maximum and minimum demand periods, and as such, are not expected to have a material impact on the following classes of market benefit that are associated with the wholesale electricity market:
  - Changes in price-responsive voluntary load curtailment, since there is no material impact on wholesale electricity market prices.
  - Changes in ancillary services costs.
  - Competition benefits.

- **Changes in network losses** – while augmentation options to support voltages at times of high and low demand could marginally impact network losses, it is not expected the increase, beyond that inherently captured in the power system analysis modelling, will be material in relation to the RIT-T assessment for a specific option, as all options which can support voltages will have a similarly small impact on network losses.
- **Any additional option value** – option value for this RIT-T is already inherently considered through the staged timing of investment in the portfolio of options needed to form the credible option, and in part through the various scenarios considered. No additional option value has been explicitly determined for this PACR due to the complexity of doing so outweighing any potential benefits.

3.2 Quantification of classes of material market benefit for each credible option

Consistent with the PADR, the classes of market benefits and costs that are considered material to this RIT-T include:

- Changes in voluntary/involuntary load curtailment.
- Changes in emissions arising from changes in load curtailment.
- Changes in fuel consumption arising through different patterns of generation dispatch.
- Changes in costs for parties, other than for AVP, due to differences in the operational and maintenance costs of different plant.
- Changes in emissions arising through different patterns of generation dispatch.

The next sections further describe the main market benefits of each credible option.

3.2.1 Changes in voluntary/involuntary load curtailment

Changes in load curtailment are the primary source of market benefits identified for Pillar 1 in this RIT-T. For all credible options, this market benefit has been captured via the reduction in the amount of expected unserved energy (EUSE). The market benefit value was then quantified using the calculated EUSE and the Value of Customer Reliability (VCR)[13].

3.2.2 Changes in fuel consumption

Changes in fuel consumption through different patterns of generation dispatch are the primary source of market benefits identified for Pillar 2 in this RIT-T. For all credible options, this market benefit has been captured via the reduction in the need for AEMO as system operator to intervene in the market via directing generators online, which can be quantified using:

- Fuel costs of generators dispatched through market intervention.
- Start-up fuel costs of generators dispatched through market intervention.

[13] VCR used was $48,512 as outlined in Table 32 of the 2023 IASR, at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf.

3.2.3 Changes in costs to other parties

Changes in costs to other parties is the other class of market benefits quantified for Pillar 2 in this PADR. 'Other parties' in this context refers to costs incurred by market participants due to:

- Differences in variable operating and maintenance costs of generators dispatched through market intervention.
- Start-up operating and maintenance costs of generators dispatched through market intervention.

3.2.4 Emissions reduction

Following an amendment to the NEO to incorporate an emissions reduction objective[14] and subsequent NER rule changes (see more in Section 2.3.4), emissions reduction is a class of market benefit quantified in this PADR.

For Pillar 1, this market benefit has been captured for credible options via an increase in emissions due to increased supply to meet avoided EUSE.

For Pillar 2, this market benefit has been captured for credible options via the reduction in the need for AEMO as system operator to intervene in the market via directing generators online which might displace less emissions-intensive generation otherwise dispatched.

The benefit can be quantified for either Pillar using:

- Emissions intensity of generators dispatched or runback as a result of credible options, compared with emissions intensity of generators that they displace, if any, as provided in the 2023 IASR.
- The value of emissions reduction.

3.3 The 'do nothing' base case

The 'do nothing' base case is the case where the RIT-T proponent does not implement a credible option to meet the identified need. The benefit of each credible option is assessed relative to this 'do nothing' base case.

3.3.1 Managing under-voltages in the 'do-nothing' case

For this RIT-T, if AVP does not implement a credible option to manage under-voltages, then AEMO as system operator would need to pre-contingently curtail load to maintain the power system in a satisfactory and secure operating state, and to maintain sufficient reactive power margins.

The underlying involuntary load curtailment costs calculated as EUSE for the 'do nothing' base case over the 10-year modelling period are illustrated in Table 8 below. These are derived from periods where forecast demand exceeds the maximum supportable demand or results in thermal loading that exceeds a relevant thermal limit. See Figure 3, Figure 4 and Figure 5 for annual maximum demand forecasts for the 2023 ESOO Central scenario for 10% POE, and the respective maximum supportable demand for the relevant load areas for Pillar 1 across the modelling period for the 'do nothing' base

[14] See https://www.aer.gov.au/system/files/2023-09/AER%20-%20Guidance%20on%20amended%20National%20Energy%20Objectives%20-%20Final%20guidance%20note%20-%20September%202023.pdf.

case. The load areas shown in these figures were determined as those that are most effective to curtail load and to relieve under-voltage exceedances.

In these figures, where the connection point forecast exceeds the maximum supportable demand is where EUSE is expected in that year during high demand periods, and these are the years where investment in this RIT-T, where economic, would be required. Where not economic (that is, where the EUSE costs are not enough to justify the cost of investment), load curtailment or other operational measures available would be required to manage under-voltage exceedances during these high demand periods.

In Figure 3, the maximum supportable demand decreases due to increased loading in the western metropolitan Melbourne area, in particular at Geelong. The load at Geelong impacts the maximum supportable demand at Deer Park but load curtailment at Deer Park is much more effective than at Geelong. As the loads at both these terminal stations have historically been highly correlated, this is reflected in the decreasing trend of supportable demand post-2030.

In Figure 4, the maximum supportable demand drastically dips in 2028 due to the retirement of the 45 MVAr 66 kV capacitor at Tyabb in December 2027. It increases in 2029, as the voltage needs at Tyabb are alleviated due to a change in the network configuration in Latrobe Valley following retirement of Yallourn, but further increases in 2030 due to VNI West. However as loading in the eastern metropolitan area increases, the loading of the Cranbourne transformer increases and therefore max supportable demand in Cranbourne and Tyabb decreases throughout the early 2030s. Tyabb and Cranbourne load blocks were found to be most effective in alleviating the voltage constraint at Tyabb.

The maximum supportable demand at Rowville dips in 2028 due to the retirement of the 200 MVAr 220 kV capacitor at Rowville on the No. 1-2 220 kV bus group and 50 MVAr 66 kV capacitor at Templestowe, as shown in Figure 5. After Yallourn retires in 2028-29, switching arrangements alleviate the voltage needs at Rowville. The maximum supportable demand further increases in 2030 due to VNI West. However, as loading in the eastern metropolitan area increases, the loading of the Rowville A1 transformer increases and therefore the maximum supportable demand in Malvern, Heatherton and Springvale decreases. Malvern, Heatherton and Springvale load blocks were found to be most effective in alleviating the voltage constraint at Rowville on the No. 3-4 220 kV bus group.

Table 8 'Do nothing' involuntary load curtailment costs ($M)

Option	Weighted outcomes [B]									
	2025[A]	2026	2027	2028	2029	2030	2031	2032	2033	2034
Do nothing ($M)	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.3
USE (MWh)	0.0	0.0	0.3	1.2	2.3	7.5	16.9	42.3	224.9	483.7

A. Financial year ending.
B. Involuntary load curtailment costs and MWh arising after weighting of scenarios.

The subsequent cost of emissions due to involuntary load curtailment (in this case negative costs) are shown for the 'do nothing' base case for the 10-year modelling period in Table 9.

Table 9 'Do nothing' emissions costs ($M)

Option	Weighted – underlying costs $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Do nothing	0.00	0.00	-0.00[A]	-0.00[A]	-0.00[A]	-0.00[A]	-0.00[A]	-0.00[A]	-0.02	-0.04

A. Negative emissions costs exist however are too small to show to two decimal places.

Figure 3 'Do nothing' maximum supportable demand at the critical site Deer Park 220 kV

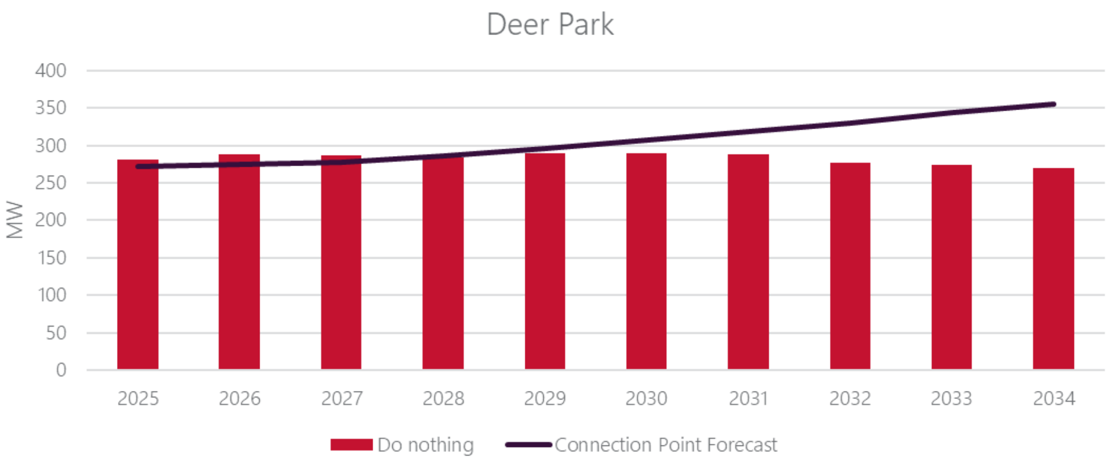
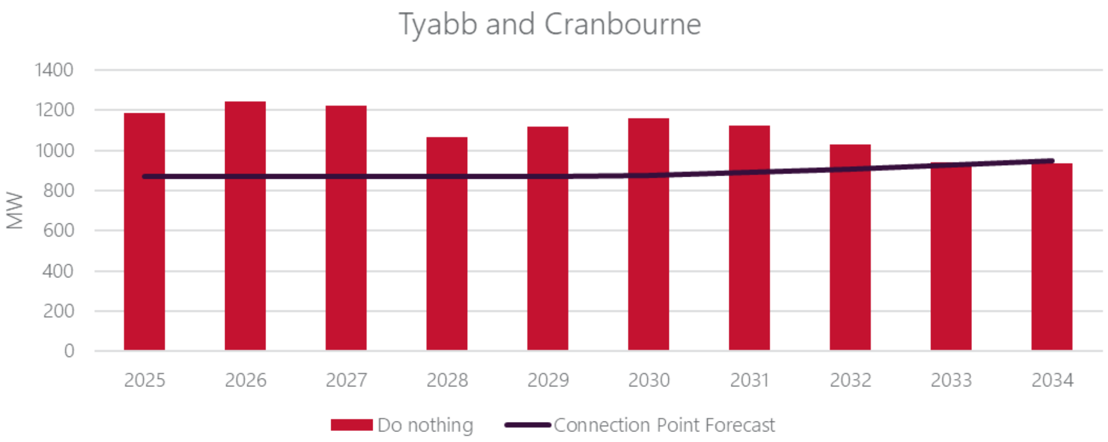
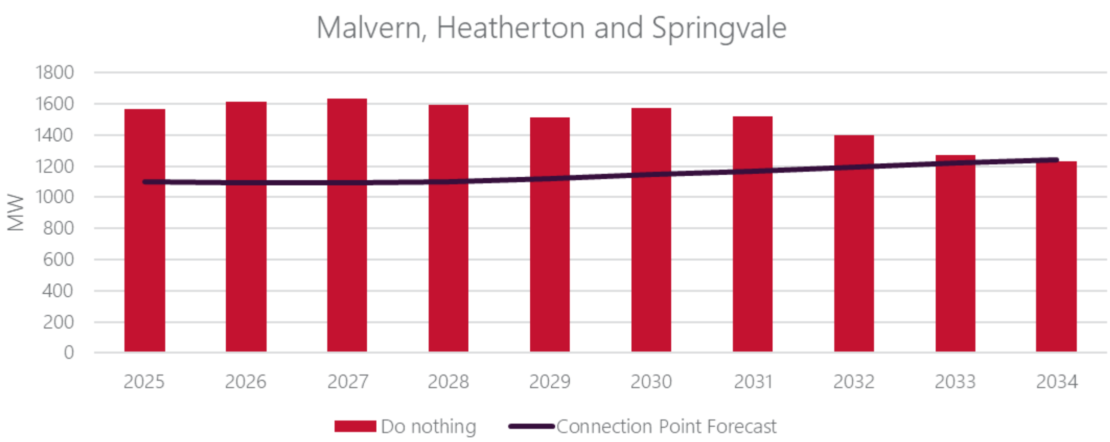


Figure 4 'Do nothing' maximum supportable demand at the critical site Tyabb 220 kV[A]



A. Tyabb and Cranbourne load blocks are shown as they were found to be most effective in alleviating the voltage constraint at the critical site Tyabb 220 kV.

Figure 5 'Do nothing' maximum supportable demand at the critical site Rowville 220 kV[A]



A. Malvern, Heatherton and Springvale load blocks are shown as they were found to be most effective in alleviating the voltage constraint at the critical site Rowville 220 kV.

3.3.2 Managing over-voltages in the 'do-nothing' case

For this RIT-T, if AVP does not implement a credible option to manage over-voltages, AEMO as system operator would be required to intervene in the market, either by directing generators or entering into an NMAS contract, to maintain the power system in a satisfactory and secure operating state.

The cost of directing generators or activating an NMAS contract (if one was entered into)[15] has been calculated using generator fuel costs (including fuel used in start-up) and operating and maintenance costs. These costs are shown for the 'do nothing' base case for the 10-year modelling period in Table 10. The total cost associated with this intervention is a sum of the out of merit order dispatch costs and start-up costs of the generators directed online, and a deduction of the dispatch costs of generation that is subsequently displaced in the market. The displaced generation is variable renewable energy (VRE) where dispatched online and available for curtailment, or otherwise coal-fired synchronous generation where dispatched online.

Table 10 'Do nothing' out-of-merit-order annual dispatch costs ($M)

Option	Weighted outcomes									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Gas gen fuel cost ($/MWh)	223	193	172	170	169	170	172	172	173	176
Opex ($/MWh)	10	10	10	10	10	10	10	10	10	10
Out of merit order dispatch (MWh)	0	0	606	6,978	21,739	41,389	65,120	64,814	83,334	89,280
Out of merit order start-up costs ($M)	0	0	0.00	0.04	0.13	0.26	0.41	0.40	0.52	0.57
Out of merit order dispatch costs ($M)	0	0	0.11	1.24	3.82	7.25	11.46	11.39	14.65	16.11
Displaced gen dispatch costs ($M)	0	0	0.00	0.02	0.08	0.15	0.24	0.24	0.30	0.31
Total costs associated with out of merit order dispatch of gas gen ($M) [A]	0	0	0.11	1.26	3.87	7.35	11.63	11.55	14.87	16.37

A. Total costs = "out of merit order start-up costs" + "out of merit order dispatch costs" – "displaced gen dispatch costs"

The subsequent cost of emissions due to directing generators or activating a NMAS contract are shown for the 'do nothing' base case for the 10-year modelling period in Table 11.

Combining the costs from both pillars of the identified need, the total costs associated with managing voltages in the 'do nothing' base case are shown in Table 12.

[15] Assumed to have the same underlying costs (based on fuel and operating and maintenance costs) as directing generators.

Table 11 'Do nothing' emissions costs ($M)

Option	Weighted outcomes									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Out of merit order dispatch emissions (tonne)	0	0	409.9	4,664.3	14,473.1	27,499.0	43,118.8	42,683.1	54,586.8	58,301.4
Displaced gen dispatch emissions (tonne)	0	0	178.3	1,884.1	6,730.7	12,868.7	20,142.2	20,073.4	24,974.8	25,935.9
VER ($/kg)	0.075	0.080	0.084	0.089	0.095	0.105	0.114	0.124	0.135	0.146
Emissions costs associated with out of merit order dispatch of gas gen ($M)	0.00	0.00	0.02	0.25	0.74	1.54	2.62	2.80	4.00	4.73

Table 12 'Do nothing' total underlying costs ($M)

Option	Weighted – underlying costs $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Pillar 1	0	0	0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
Pillar 2	0	0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1
Total	**0**	**0**	**0.1**	**1.6**	**4.7**	**9.3**	**15.0**	**16.4**	**29.7**	**44.3**

3.4 Credible options assessed

This PACR considered four credible options, as summarised in Table 13 and further detailed in this section, that are considered capable of meeting the identified need.

The four options assessed are the same as those assessed in the PADR, albeit with refinement of the terminal station sites for the Stage 1 reactors, which were revised following further joint planning with AusNet Services to determine the most economically and technically feasible location of assets to meet the identified need.

The assessment found Option 1 to have the highest weighted net market benefits under the assessed scenarios by more than $10 million compared with the option that yields the second highest net market benefits (Option 4).

Table 13 PACR options and weighted assessment outcomes

Option	Description	Total network MVAr invested	Capital cost ($M)	Combined pillars weighted gross market benefit in NPV ($M)	Combined pillars weighted net market benefit in NPV ($M)
Option 1 (Preferred)	Capacitors and reactors	600	47.5	285.9	255.1
Option 2	Capacitors and reactors, and non-network service in eastern metropolitan Melbourne	500 + confidential MVAr support	40.8 + confidential cost	284.1	Confidential[A] (but less than the net market benefits of Option 1)

Option	Description	Total network MVAr invested	Capital cost ($M)	Combined pillars weighted gross market benefit in NPV ($M)	Combined pillars weighted net market benefit in NPV ($M)
Option 3	Capacitors and reactors, and non-network option at Deer Park	400 + confidential MVAr support	313.7	284.0	68.9
Option 4	Option 1 with one capacitor and one reactor displaced by one SVC in 2029	450	59.7	286.8	244.4

A. Costs are based on information for an eastern metropolitan Melbourne BESS provided on a confidential basis and therefore the net market benefits that use these costs as an input are also confidential.

In the PADR, prior to the detailed cost-benefit assessment of credible options, AVP performed an initial, qualitative screening of a suite of potentially feasible network and non-network options as identified in the PSCR. Those which were identified as being technically and economically feasible were tested in the detailed cost-benefit assessment of credible options. Those which were identified as not being technically or economically feasible enough for further consideration in the RIT-T, detailed in Section 3.8 of the PADR, included options to widen the operational voltage limits in areas needing voltage management support, including Keilor 500 kV and Deer Park 220 kV. More information on these options and why they were not pursued further is in Section 3.3.1 of the PADR.

AVP only assessed non-network options that were provided in submissions to the consultation on the PSCR and subsequently made known to AVP as being available as a credible option. More non-network options were provided in submissions to the consultation on the PADR; these are discussed in Section 3.6.1 below.

3.4.1 Option 1 description and market benefit

Credible Option 1 consists of shunt capacitors to address Deer Park and eastern metropolitan Melbourne voltage support needs during high demand, and shunt reactors to address general metropolitan Melbourne voltage support needs during low demand, at sites that effectively address these needs and can accommodate new plant considering land, environmental and social constraints. The location of reactors, to be procured in Stage 1, have been revised since the PADR following further joint planning with AusNet Services investigating the sites most feasibly able to host new assets, as described in section 2.4.1.

The optimal investment size, locations, and timing identified for credible Option 1 are:

- 3 x 100 MVAr reactors, two at the Altona Terminal Station 220 kV and one at the Brooklyn Terminal Station 220 kV, in 2028-29 (to address Pillar 2).
- 1 x 100 MVAr capacitor at Deer Park Terminal Station 220 kV in 2030-31 (to address Pillar 1).
- 2 x 100 MVAr capacitors in eastern metropolitan Melbourne in 2033-34 (to address Pillar 1).

Table 14 shows the annual net market benefits of Option 1 across the 10-year assessment period considering the staged delivery of reactors and capacitors in line with the optimal sizes and timings above.

Table 14 Option 1 Net Market Benefits delivered in addressing the identified need ($M)

Stage	Capital cost (cumulative)	Annualised cost (cumulative)	Weighted – net benefits $M										
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Assumed benefit until staged end of life
1 (2029)	27.0	2.1					3 x 100 MVAr reactors						
2 (2031)	34.2	2.7							1 x 100 MVAr capacitor at Deer Park				
3 (2034)	47.5	3.9										2 x 100 MVAr in East Metro	
Total	47.5	3.9					2.6	6.8	12.4	13.7	26.2	40.4	37.4

A. Annualised cost represents the annualised capital cost plus operating and maintenance costs.

3.4.2 Option 2 description and market benefit

Credible Option 2 consists of:

- shunt capacitors to address Deer Park and eastern metropolitan Melbourne voltage support needs during high demand and shunt reactors to address metropolitan Melbourne voltage support needs during low demand, at sites that effectively address these needs and can accommodate new plant considering land, environmental and social constraints.
- A non-network BESS service in eastern metropolitan Melbourne that provides both generating and absorbing reactive power capabilities to reduce the size of network investment needed in shunt capacitors and shunt reactors above.

As detailed in the PADR, the optimal investment size and timing for credible Option 2 is:

- 3 x 100 MVAr reactors on the 220 kV level in 2028-29 (to address Pillar 2).
- 1 x 100 MVAr capacitor for Deer Park 220 kV in 2030-31 (to address Pillar 1).
- 1 x 100 MVAr capacitor in eastern metropolitan Melbourne in 2033-34 (to address Pillar 1).
- Non-network BESS service in eastern metropolitan Melbourne in 2033-34 (to address Pillars 1 and 2).

Given the confidential nature of the non-network BESS service, a table equivalent to Table 14 is not possible for Option 2.

3.4.3 Option 3 description and market benefit

Credible Option 3 consists of:

- shunt capacitors to address Deer Park and eastern metropolitan Melbourne voltage support needs during high demand and shunt reactors to address metropolitan Melbourne voltage support needs during low demand, at sites that effectively address these needs and can accommodate new plant considering land, environmental and social constraints.
- A non-network BESS option at Deer Park Terminal Station 220 kV that provides both generating and absorbing reactive power capabilities to reduce the size of network investment needed in shunt capacitors and shunt reactors above.

As detailed in the PADR, the optimal investment size and timing for credible Option 3 is:

- 3 x 100 MVAr reactors on the 220 kV level in 2028-29 (to address Pillar 2).

- Non-network BESS option at Deer Park 220 kV in 2030-31 (to address Pillars 1 and 2).
- 1 x 100 MVAr capacitor in eastern metropolitan Melbourne in 2033-34 (to address Pillar 1).

Table 15 shows the annual net market benefits of Option 3 across the next 10 years considering the staged delivery of this option in line with the optimal sizes and timings above.

Table 15 Option 3 net market benefits delivered in addressing the identified need ($M)

Stage	Capital cost (cumulative)	Annualised cost (cumulative)	Weighted – net benefits $M										
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Assumed benefit until staged end of life
1 (2029)	27.0	2.1					3 x 100 MVAr reactors						
2 (2031)	307.0	29.3							Deer Park non-network service				
3 (2034)	313.7	29.9										1 x 100 MVAr in East Metro	
Total	313.7	29.9					2.6	6.8	-14.2	-12.9	-0.2	14.2	11.2

A. Annualised cost represents the annualised capital cost plus operating and maintenance costs.

3.4.4 Option 4 description and market benefit

Credible Option 4 consists of:

- shunt capacitors to address Deer Park and eastern metropolitan Melbourne voltage support needs during high demand and shunt reactors to address metropolitan Melbourne voltage support needs during low demand, at sites that effectively address these needs and can accommodate new plant considering land, environmental and social constraints.
- A single dynamic plant (in this example an SVC) that provides both generating and absorbing reactive power capabilities to reduce the size of network investment needed in shunt capacitors and shunt reactors above.

The PADR demonstrated that establishing an SVC defers the need for one of the three reactors included in Option 1 when maximising net benefits, resulting in a benefit in bringing forward the SVC from 2033-34 when it displaces the need for the eastern metropolitan Melbourne capacitors.

As detailed in the PADR, the optimal investment size and timing for credible Option 4 is:

- 2 x 100 MVAr reactors on the 220 kV level in 2028-29. (to address Pillar 2).
- 1 x 150 MVAr SVC at Malvern 220 kV in 2028-29. (to address Pillar 1 and 2).
- 1 x 100 MVAr capacitor at Deer Park 220 kV in 2030-31. (to address Pillar 1).

Table 16 shows the annual net market benefits of Option 4 across the next 10-year assessment period considering the staged delivery of reactors, capacitors, and an SVC in line with the optimal sizes and timings above.

Table 16 Option 4 net market benefits delivered in addressing Pillars 1 and 2 of the identified need ($M)

Stage	Capital cost (cumulative)	Annualised cost (cumulative)	Weighted – net benefits $M										
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Assumed benefit until staged end of life
1 (2029)	52.4	4.0					2 x 100 MVAr reactors and 1 x 150 MVAr SVC in East Metro						
2 (2031)	59.7	4.6							1 x 100 MVAr capacitor at Deer Park				
Total	57.3	4.4					0.6	4.9	10.4	11.8	24.9	39.2	36.2

A. Annualised cost represents the annualised capital cost plus operating and maintenance costs.

3.5 Material inter-network impact

Consistent with the PADR, neither the reactor, capacitor, nor non-network options have a material inter-network impact, since they do not materially impact interconnector limits.

3.6 PACR updates to options

3.6.1 Non-network options proposed in PADR submissions

AVP has qualitatively assessed non-network option submissions to the PADR, comparing them where appropriate with similar submissions to the PSCR which were assessed in detail in the PADR cost-benefit assessment. Based on the outcomes of this qualitative assessment, non-network options proposed would not economically displace the reactors and capacitors included in Option 1 (the Preferred Option).

3.6.2 Reactor locations refined

AVP has engaged with AusNet Services and subsequently reviewed the locations for new reactors that were identified in the PADR following desktop reviews undertaken to identify and understand land assembly options, environment, planning, and social constraints, and relevant cost factors to achieve planning and environment regulatory obligations[16].

Following this review, AVP has revised the optimal sites for new reactors (considering locations that can better accommodate new equipment, while maintaining similar technical effectiveness at meeting the Identified Need).

AVP completed additional desktop analysis since the PADR and subsequently does not expect the new preferred sites to have the potential to cause significant environmental or social impacts. Achievement of delivery timeframes is subject to further detailed studies, investigations and stakeholder engagement that may be required to obtain all necessary planning and environmental approvals.

In addition to revising the optimal reactor locations, AVP has also updated the net market benefits based on updated cost estimates as presented in Section 3.6.33.6.3 below.

[16] See Section 3.2 of the PADR for more information.

Table 17 below compares the PADR and PACR Option 1 sites, noting:

- The locations for the 3 x 100 MVAr reactors of Stage 1 have been amended considering joint planning outcomes with AusNet Services.

Table 17 Sites for new reactors and capacitors

Equipment	Procurement stage (Timing)	PADR Option 1 sites	PACR Option 1 sites
100 MVAr Reactor no1	Stage 1 (2028-29)	South Morang 220 kV	Altona 220 kV
100 MVAr Reactor no2	Stage 1 (2028-29)	Thomastown 220 kV	Altona 220 kV
100 MVAr Reactor no3	Stage 1 (2028-29)	West Melbourne 220 kV	Brooklyn 220 kV
100 MVAr Capacitor no1	Stage 2 (2030-31)	Deer Park 220 kV	Deer Park 220 kV
100 MVAr Capacitor no2	Stage 3 (2033-34)	Malvern 220 kV	Malvern 220 kV
100 MVAr Capacitor no3	Stage 3 (2033-34)	Tyabb 220 kV	Tyabb 220 kV

3.6.3 Option costs

Class 5A (+/- 30%) cost estimates for individual equipment and the likely build components were developed using the AEMO 2023 Transmission Cost Database (TCD) and the 2024 ISP Inputs and Assumptions Workbook, and have been escalated to real 2024 dollars as presented in Table 18. Each credible option cost estimate has been built up from the individual asset costs outlined in this section.

The TCD is substantially based on the Association for Advancement of Cost Engineering (AACE) international classification system commonly used in many industries[17]. The cost estimates include known and unknown risk allowances, in line with the TCD, which is presented as a proportion ($ million) of the total option cost in Table 18 and is considered a contingency in line with AEMO's Mott MacDonald: Transmission Cost Database Update final report released in July 2023[18].

Table 18 Cost estimates of individual assets

Asset Description	Estimated capital cost ($M)
Options that contribute to Pillar 1 identified need only	
220 kV 100 MVAr shunt capacitor at Deer Park	7.22
220 kV 100 MVAr shunt capacitor at Malvern	6.66
220 kV 100 MVAr shunt capacitor at Tyabb	6.66
Deer Park low voltage limit paper uprate	0
Options that contribute to Pillar 2 identified need only	
220 kV 100 MVAr shunt reactor at South Morang, Thomastown, West Melbourne, Altona, Brooklyn or Keilor terminal stations	8.98
Options that contribute to both Pillar 1 and Pillar 2 identified needs	
Non-network voltage management services in eastern metropolitan Melbourne	0[A]
Non-network voltage management services at Deer Park 220 kV	280.10[A,B]

[17] 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.

[18] 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.

Asset Description	Estimated capital cost ($M)
220 kV 150 MVAr SVC at Malvern	34.47

A. Excludes annual contract costs of non-network options.
B. Based on new entrant build costs included in the 2024 ISP Inputs and Assumptions Workbook.

Annual operating and maintenance costs are in addition to the capital costs shown in Table 18, and are:

- For network options, estimated as 1% of the capital costs, aligned with the 2023 *Transmission Expansion Options Report* (TEOR)[19].
- For uncommitted non-network generator and BESS options, aligned with the fixed and variable operating and maintenance costs (FOM and VOM) included in the 2024 ISP Inputs and Assumptions Workbook.
- For committed non-network generator and BESS options, a fixed confidential amount based on information provided to AVP on a confidential basis.

3.7 Preferred option

The Preferred Option that addresses both pillars of the identified need and maximises net market benefits for consumers, is Option 1, which comprises:

- Stage 1, in 2028-29 (earliest possible investment), to address Pillar 2 needs:
  - 2 x 100 MVAr shunt reactors at Altona Terminal Station 220 kV.
  - 1 x 100 MVAr shunt reactor at Brooklyn Terminal Station 220 kV.
- Stage 2, in 2030-31, to address Pillar 1 needs in western metropolitan Melbourne (namely Deer Park Terminal Station):
  - 1 x 100 MVAr shunt capacitor at Deer Park Terminal Station 220 kV.
- Stage 3, in 2033-34, to address Pillar 1 needs in metropolitan Melbourne more generally:
  - 1 x 100 MVAr shunt capacitor at Malvern 220 kV.
  - 1 x 100 MVAr shunt capacitor at Tyabb 220 kV.

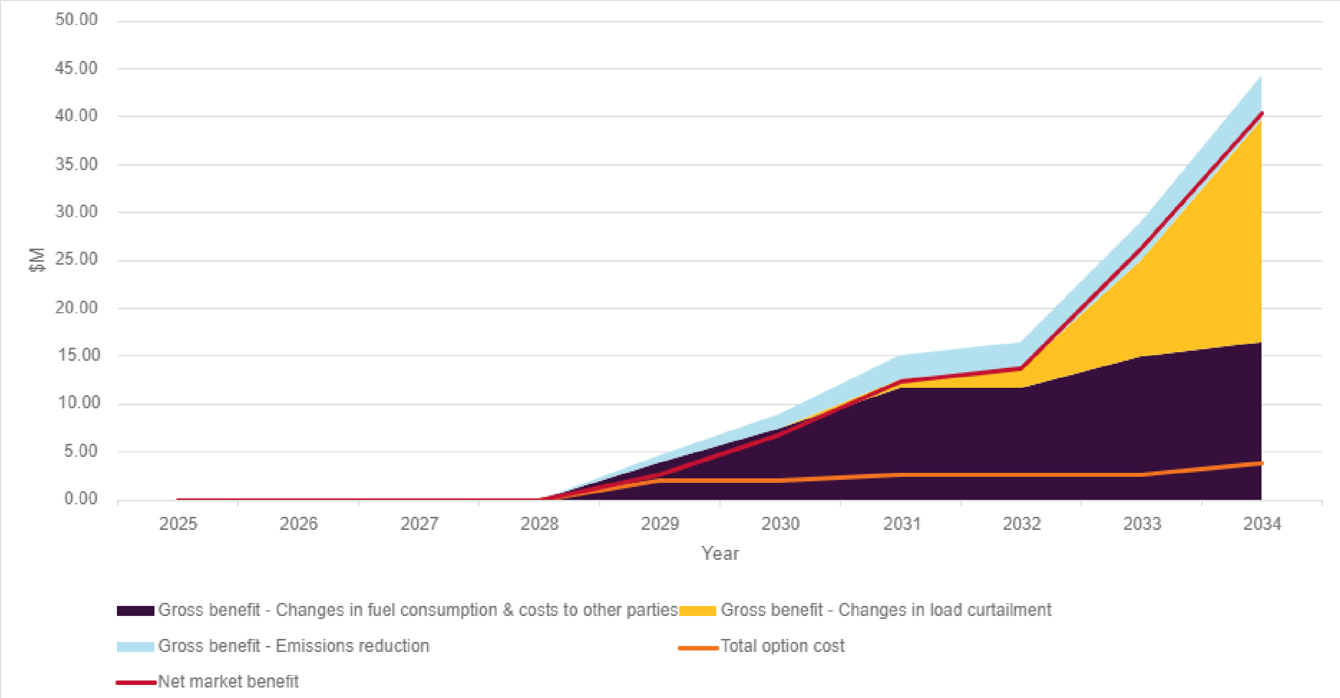
This option is estimated to have a capital cost of $47.5 million, with a 1% of capital annual operating and maintenance cost.

It is estimated to deliver $285.9 million in gross market benefits and $255.1 million in net market benefits on a net present value basis, through classes of material market benefits quantified in the cost-benefit assessment as detailed in Sections 2.3 and 3.2.

Figure 6 shows the annual gross market benefits by material market benefits class, as well as the investment cost and net market benefits of the Preferred Option. The market benefits reflect reductions in generator fuel and start-up costs, reductions in involuntary load curtailment costs, and changes in emissions costs (noting that benefits from emissions reduction for Pillar 1 are too small to be visible on the graph).

[19] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-transmission-expansion-options-report.pdf.

Figure 6 Annual gross benefits, investment cost and net market benefits of Option 1 the Preferred Option ($M)



The Preferred Option comprises three stages of delivery. Procurement of Stage 1 will commence immediately after completion of this RIT-T and its associated dispute period to enable assets to be delivered by 2028-29 when the investment is needed. Procurement of Stage 2 is expected to commence around July 2027 and procurement of Stage 3 is expected to commence around July 2030. However, supply, demand, and network developments (as detailed in Section 2.5) that may erode the market benefits of Stage 2 and Stage 3 and defer the need for investment will be monitored and AVP will adjust course for Stage 2 and Stage 3 as needed.

Table 19 is an indicative timeline of activities from completion of this RIT-T to the delivery of all three stages of the Preferred Option, considering a 30-month lead time for 220 kV shunt reactors and a 24-month lead time for 220 kV shunt capacitors, for asset delivery. AVP notes that asset delivery times are subject to change due to future supply chain uncertainty, as well as any project approval, land and environmental constraints not yet understood. AVP will continue to monitor these areas and procurement and delivery timelines will be updated and optimised where required.

Table 19 Indicative procurement and delivery timeline

Activity	Timeline	Duration
PACR published and RIT-T completed	December 2024	
RIT-T dispute period	December 2024 – January 2025	30 days
Stage 1 – 3 x reactors delivered by 2028-29:		
• **Procurement**	January 2025 – January 2026	12 months
• **Asset delivery**	January 2026 – July 2028	30 months
• **Stage 1 delivered**	July 2028 (start of FY 2028-29)	
Stage 2 – 1 x capacitor at Deer Park delivered by 2030-31:		

Activity	Timeline	Duration
• **Monitor supply, demand, and network developments since completion of the RIT-T before commencing procurement.**	January 2025 – July 2027 (or until start of procurement)	NA
• **Procurement**	July 2027 – July 2028	12 months
• **Asset delivery**	July 2028 – July 2030	24 months
• **Stage 2 delivered**	July 2030 (start of FY 2030-31)	
Stage 3 – 2 x capacitors delivered by 2033-34:		
• **Monitor supply, demand, and network developments since completion of the RIT-T before commencing procurement.**	January 2025 – July 2030 (or until start of procurement)	NA
• **Procurement**	July 2030 – July 2031	12 months
• **Asset delivery**	July 2031 – July 2033	24 months
• **Stage 3 delivered (marks completion of delivery of the Preferred Option)**	July 2033 (start of FY 2034)	

4 Conclusion and next steps

This PACR identifies the preferred option to manage metropolitan Melbourne voltages within limits to be installing three 100 MVAr reactors on the 220 kV level, two at Altona Terminal Station and one at Brooklyn Terminal Station, by 2028-29, one 100 MVAr capacitor on the 220 kV level, at Deer Park Terminal Station, by 2030-31, and two 100 MVAr capacitors on the 220 kV level, one at Malvern Terminal Station and one at Tyabb Terminal Station, by 2033-34.

AVP will soon commence procurement of the preferred option, which has an estimated total capital cost of $47.5 million and expected net market benefits over the life of the assets of $255.1 million.

The augmentations listed in Section 3.7 above constitute the Preferred Option and satisfy the RIT-T.

AVP will undertake the process set out in the National Electricity Law and the NER to procure the required voltage management services under this RIT-T, and AVP will keep stakeholders informed through project updates during the procurement and implementation activities.

A1. Checklist of compliance clauses

Table 20 sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of NER 5.16.4 (v).

Table 20 Checklist of compliance clauses

NER clause	Summary of requirements	Relevant section(s) in the PACR
5.16.4 (v)	The project assessment conclusions report must set out:	
	(1) the matters detailed in the project assessment draft report as required under NER 5.16.4 (k)	See below
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties	Section 2.4.2
5.16.4 (k)	The project assessment draft report must include:	
	(1) A description of each credible option assessed	Section 3.4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Section 2.4.2
	(3) quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option	Sections 3.2 and 3.6.3
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost	Section 2
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material	Section 3.1
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions)	N/A
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	Sections 3.3 and 3.4
	(8) the identification of the proposed preferred option	Section 3.7
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission	Sections 3 and 4
	(10) if each of the following apply to the RIT-T project: (i) the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination); and (ii) AEMO is not the sole RIT-T proponent, the RIT reopening triggers applying to the RIT-T project	Although not applicable, because the capital cost of the preferred option is less than $100 million and AEMO is the sole RIT-T proponent, key potential future impacts and material change triggers have been included in section 2.5.