Melbourne Metropolitan Voltage Management – Project Assessment Draft Report

26 July 2024

Regulatory Investment Test for Transmission – Victoria

Important notice

Purpose

AEMO has prepared this Project Assessment Draft Report to meet the consultation requirements of clause 5.16.4 of the National Electricity Rules.

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AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024 (scan QR code to read).

Executive summary

Investment is required to maintain Victorian Declared Shared Network (DSN) voltages in the metropolitan Melbourne region within operational and design limits, during both maximum demand and minimum 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 greater need for voltage management support. This is needed in the metropolitan Melbourne area of Victoria to maintain voltages within lower limits during high demand and within upper limits during low demand.

In October 2023, AEMO Victorian Planning (AVP) initiated this Regulatory Investment Test for Transmission (RIT-T) through the publication of a Project Specification Consultation Report (PSCR), the first stage of the RIT-T process, to assess the technical and economic benefits of delivering additional voltage management support in metropolitan Melbourne. 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 PSCR identified a need comprising 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 during high demand periods when voltages are at risk of falling below limits.
- **Identified Need – Pillar 2: the need to manage over-voltages**: the need to maintain the power system in a satisfactory and secure operating state in metropolitan Melbourne during low demand periods when voltages are at risk of rising above limits.

Through publication of the PSCR, AVP sought feedback from stakeholders on the identified need and on the range of credible options being considered. AVP also sought information from providers of potential non-network solutions capable of providing voltage management support.

AVP has now assessed these credible options, and has identified the proposed preferred option, including its optimal size, technology, location, and investment timing and staging, that is projected to meet the identified need while maximising net economic benefits.

This Project Assessment Draft Report (PADR) marks stage two of the RIT-T process. The report reconfirms the nature of the identified need, summarises AVP's technical and economic assessment of the credible options, and justifies selection of the proposed preferred option. Through publication of this PADR, AVP is now seeking feedback on this analysis and recommendation.

The proposed preferred option

The proposed preferred option identified in this PADR is to progressively install or contract the reactive services of:

- 3 x 100 megavolt amperes reactive (MVAr) shunt reactors on the 220 kilovolts (kV) level, one each at South Morang, Thomastown, and West Melbourne Terminal Stations, to be in service by 2029.
- 1 x 100 MVAr shunt capacitor on the 220 kV level at Deer Park Terminal Station to be in service by 2031.
- 2 x 100 MVAr shunt capacitors on the 220 kV level, at Malvern and Tyabb Terminal Stations to be in service by 2034.

The proposed preferred option has a capital cost of approximately $45.6 million (in present value terms) and yields the highest net market benefits when weighted across all reasonable scenarios and sensitivities.

The PADR analysis identifies that investing in this option in a staged manner will deliver a net present economic benefit of approximately $256.4 million, by:

- reducing costs of involuntary load shedding that would otherwise need to occur during high demand periods to manage under voltage risks; and
- reducing fuel, operating and maintenance (O&M) and emission costs that would otherwise be incurred through dispatch of additional thermal generators to manage over-voltages during light load periods.

Procurement of the first stage, being 3 x 100 MVAr shunt reactors on the 220 kV level, needs to commence next year at the latest based on an anticipated lead time of 18-24 months for this option type, to ensure they can be in service by 2029 when required. The subsequent stages of the preferred option will be progressively procured to meet the required in-service dates provided that AVP is satisfied that the identified need still remains and changes in the market have not eroded the net market benefits for consumers.

Other credible options

AVP considered a range of credible network and non-network options with the capability to manage voltages in metropolitan Melbourne during either high demand or low demand periods separately, or high demand and low demand periods together.

These are illustrated in Table 1, along with their estimated capital cost and weighted net market benefits in net present value (NPV) terms across all scenarios. Option 1, the proposed preferred option, is identified as the option with the largest net market benefit.

Table 1 Weighted net market benefits for all options (NPV in real June 2023 dollars)

Option	Description	Capital Cost ($M)	Weighted – net market benefit ($M)
Option 1	• 3 x 100 MVAr shunt reactors on the 220 kV level in 2029 • 1 x 100 MVAr shunt capacitor at Deer Park 220 kV in 2031 • 1 x 100 MVAr shunt capacitor at Malvern 220 kV in 2034 • 1 x 100 MVAr shunt capacitor at Tyabb 220 kV in 2034	45.6	256.4
Option 2	• 3 x 100 MVAr shunt reactors on the 220 kV level • 1 x 100 MVAr shunt capacitor at Deer Park 220 kV in 2031 • 1 x 100 MVAr shunt capacitor at Malvern 220 kV in 2034 • Non-network battery energy storage system (BESS) service in eastern metropolitan Melbourne in 2034	39.2	Confidential[A] (but less than the net market benefits of Option 1)
Option 3	• 3 x 100 MVAr shunt reactors at 220 kV level in 2029 • Non-network BESS option at Deer Park 220 kV in 2031 • 1 x 100 MVAr shunt capacitor at Malvern 220 kV in 2034	301.1	57.0
Option 4	• 2 x 100 MVAr shunt reactors on the 220 kV level in 2029 • 1 x 150 MVAr static VAR compensator (SVC) at Malvern 220 kV in 2029 • 1 x 100 MVAr shunt capacitor at Deer Park 220 kV in 2031	57.3	246.2

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

Scenarios and sensitivities analysed

The RIT-T requires cost-benefit analysis that considers reasonable scenarios of future supply and demand under states of the world where each credible option is implemented, and compared against states of the world 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*[1].

Additional sensitivity analysis was carried out for the PADR to test the robustness of the above results by varying the assumed option cost and discount rate. Other sensitivities have been carried out exploring how future network and generation developments may impact the identified need and therefore the proposed preferred option of this PADR.

[1] Scenario assumptions and narratives are outlined in Section 2.2 of AEMO's 2023 IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Through these sensitivities, this PADR identifies that the proposed preferred option is robust to variations in key assumptions but may vary in response to a variety of network, generation and storage market developments, and other RIT-Ts underway. AVP will continue to monitor these market and RIT-T developments and will include consideration of those that have sufficiently progressed in the next stage of this RIT-T. Further, the proposed preferred solution involves three stages of proposed investment, potentially allowing further consideration for the need for solutions to resolve variations in the identified need as appropriate.

Market benefits

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

- Changes in voluntary/involuntary load curtailment.
- Changes in emissions arising from above changes in load curtailment[2].
- 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[2].

Table 1 above summarises the weighted net market benefit in NPV terms for each credible option. The net market benefit for each credible option reflects the weighted benefit across the three reasonable scenarios considered, considering these market benefit classes.

Next steps

The publication of this PADR commences the next consultation phase of this RIT-T. Following consideration of submissions on this PADR, a Project Assessment Conclusions Report (PACR) will be published in accordance with National Electricity Rules (NER) 5.16.4.

Submissions

AVP received two confidential submissions to the PSCR which are discussed in Chapter 4. AVP welcomes written submissions from all interested parties on this PADR, including comments on the inputs, analysis, and choice of preferred option. AVP also welcomes further submissions of potential non-network options to meet the identified need, to be considered in the PACR.

Submissions should be emailed to AVP_RIT-T@aemo.com.au and are due before 5.00 pm on 6 September 2024.

Submissions will be published on the AEMO website. If you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

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[2] In May 2023, Energy Ministers amended the National Electricity Objective (NEO) to incorporate an emissions reduction objective. In turn, the Australian Energy Market Commission (AEMC) launched a rule change to harmonise the national energy rules with the updated NEO. The updated NEO applies to any RIT-T project required to publish a PADR after 21 November 2023, while the AEMC rule changes finalised as of 1 February 2024 require RIT-T proponents to consider emissions reduction as a market benefit class.

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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 Draft Report (PADR) is stage two of the consultation process in relation to this Metropolitan Melbourne Voltage Management RIT-T.

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 Declared Shared Network (DSN).

In deciding whether a proposed augmentation to the DSN should proceed, AVP is required to undertake a cost -benefit analysis; in this case, a RIT-T. The purpose of a RIT-T is to identify the investment option which meets an identified need while maximising the present value of net economic market benefits to all those who produce, consume, and transport electricity in the market. 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 identifies and seeks feedback on the RIT-T analysis and on the selection of a preferred option that delivers the highest net market benefits.
- The Project Assessment Conclusions Report (PACR), which 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[3], and the RIT-T application guidelines[4].

1.2 Overview of this report

In October 2023, AVP published a PSCR[5] which identified a need for additional support to maintain transmission system voltages in metropolitan Melbourne, and presented credible options for investment to address this need.

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

[4] 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.

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

This PADR represents stage two of the RIT-T process[6], and provides:

- A description of the identified need for investment (Chapter 2).
- A description of each credible option assessed (Chapter 3).
- A summary of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit, for each credible option (Chapter 3).
- A detailed description of the methodologies and assumptions used in quantifying each class of material market benefit and cost (Chapter 5).
- Identification of all material classes of market benefits across the National Electricity Market (NEM) (Chapter 6).
  - Reasons why some classes of market benefit have not been considered as material (Section 6.1).
  - Results from a net present value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results (Sections 6.3 – 6.4).
  - Results from the sensitivity analyses (Section 6.5).
- The proposed preferred option (Chapter 7).

For the proposed preferred option, this PADR also provides:

- Details of its technical characteristics.
- The estimated construction commissioning date (year).
- A statement and accompanying detailed analysis showing that the preferred option satisfies the RIT-T.

1.3 Stakeholder submissions

AVP invites written submissions on this PADR from registered participants and interested parties.

Submissions are due before 5:00 pm on 6 September 2024, and should be emailed to AVP_RIT-T@aemo.com.au.

Submissions will be published on the AEMO website. AVP would prefer public submissions, however if you do not wish for your submission to be publicly available, please clearly stipulate this at the time of lodgement.

1.4 Next steps

The publication of this PADR commences the next consultation phase of the RIT-T process.

Following the consultation, a PACR will be published to finalise the RIT-T assessment process. The PACR will draw a conclusion on the preferred option and provide consideration to any submissions made in response to this PADR.

For further details about this RIT-T, please email AVP_RIT-T@aemo.com.au.

[6] As specified in NER 5.16.4(j) – (s), at https://energy-rules.aemc.gov.au/ner/568.

2 Identified need

The identified need for investment is to maintain transmission system voltages within operational and design limits in the metropolitan Melbourne region in Victoria, during high demand and low demand periods. This investment will:

- address an emerging voltage control network support and control ancillary services (NSCAS) gap at Deer Park Terminal Station on the 220 kilovolts (kV) level;
- ensure the power system remains in a satisfactory and secure operating state; and
- maximise net market benefits primarily through avoided involuntary load shedding, reduced fuel consumption costs, and reduced emissions costs.

2.1 Description of the identified need

The identified need was described in Chapter 2 of the PSCR[5], and is further elaborated in this PADR as the need for investment to maintain DSN 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)[7], during both maximum demand and minimum 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[8] in metropolitan Melbourne by maintaining transmission system voltages within operational and design limits, and to maintain sufficient reactive power margins[7], 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[8] 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.

The identified need has been broken into two pillars because, while the identified need is to manage DSN voltages to within limits for all system conditions, there are two distinct drivers of this need:

- The drivers of the first pillar are 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.
  - These drivers are anticipated to be alleviated to some degree by:

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

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

  - other reactive capacity that is forecast to become available in metropolitan Melbourne in the form of grid-scale storage in the coming years; and
  - a network reconfiguration of the Latrobe Valley that is proposed with the retirement of Yallourn Power Station in mid-2028[9].
- The driver of the second pillar is 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.

Although these drivers may evolve differently in the future, they are considered together in this RIT-T because they both fall under the same identified need to manage DSN voltage levels within limits. That allows the benefits associated with solutions that can address both pillars – such as synchronous condensers, static synchronous compensators (STATCOMS) and static volt ampere reactive (VAR) compensators (SVCs) – to be compared and contrasted with combinations of solutions that can address only one of the identified need pillars, such as capacitors or reactors.

Table 2 and Table 3 list the critical sites where voltage and reactive limit exceedances respectively are forecast to occur under a 'do nothing' scenario, during high demand periods and based on 10% probability of exceedance (POE)[10] forecasts for the 2023 *Electricity Statement of Opportunities* (ESOO) Central scenario[11].

Table 5 similarly lists the over-voltages forecast at critical sites during low demand periods, based on 90% POE forecasts for the 2023 ESOO Central scenario. For this PADR, AVP has conservatively assumed the needs in 2033-34 will be similar to those in 2028-29. While minimum operational demand is forecast to be much lower in 2033-34 than in 2028-29, that is in the absence of any large-scale battery charging or other developments that may help lift operational minimum demand. As the DSN will likely look very different by 2033-34, there is therefore uncertainty around the magnitude of any identified need beyond the next 10 years. AVP does not intend to fully resolve over-voltage issues forecast this far into the future in this PADR, and will continue to monitor minimum demand needs beyond 2028-29 after completion of this RIT-T.

Table 4 and Table 6 provide the equivalent MVAr capacity required at each critical site to bring these voltage exceedances within limits, for high demand and low demand periods respectively, based on the respective POE forecasts shown for the 2023 ESOO Central scenario.

These exceedances have been refined since the PSCR, based on updated information in Section 2.2 below.

In the short term, prior to delivery of solutions identified in this RIT-T, as maximum demand continues to grow and minimum demand continues to fall, AVP and AEMO (as system operator) will efficiently manage voltages within limits through operational measures and through joint planning with distribution network service providers (DNSPs).

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[9] See AVP's 2023 *Victorian Annual Planning Report* (VAPR), at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2023/2023-victorian-annual-planning-report.pdf?la=en.

[10] POE represents the statistical likelihood of the forecast being exceeded. A 10% maximum demand forecast means the forecast level of demand is likely to be exceeded one year in 10, and a 90% minimum demand forecast means demand is likely to be lower than forecast one year in 10; both represent forecast demand in extreme weather conditions.

[11] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Table 2 Pillar 1 – possible under-voltages for 2023 ESOO Central scenario, 10% POE maximum demand forecast in the next 10 years

Critical site	Low voltage limit (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.

Table 3 Pillar 1 – possible reactive margin limits[A] exceedance for 2023 ESOO Central scenario, 10% POE maximum demand forecast in the next 10 years

Critical site		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	Reactive margin	Within limits	Within limits	Within limits	Within limits	Within limits	55.8
	Reactive margin limit	62.0	62.4	62.2	62.4	62.0	62.0
Tyabb 220 kV	Reactive margin	Within limits	Within limits	Within limits	Within limits	Within limits	Within limits
	Reactive margin limit	61.0	61.5	61.2	60.0	61.0	61.0
Rowville 220 kV area[B]	Reactive margin	Within limits	Within limits	Within limits	Within limits	Within limits	Within limits
	Reactive margin limit	101.4	102.3	102.4	97.3	101.4	102.3

A. Refer to Chapter Schedule 5.1.8 for required reactive power margins defined as 1% of maximum fault level in MVA at the connection point.
B. This encompasses Rowville, Springvale, Malvern, Thomastown, Ringwood, Templestowe, Heathrow, Richmond and Brunswick on the 220 kV level, with worst-case reactive margins for this area shown for Rowville 220 kV.

Table 4 Pillar 1 – equivalent generating MVAr capacity required to bring under-voltages within limits and reactive power margins above required levels under 2023 ESOO Central scenario, 10% POE maximum demand forecast in the next 10 years

Critical site	Low voltage limit (kV)	Equivalent absorbing reactive capacity (MVAr) to bring over-voltages within limits					
		2024-25	2025-26	2026-27	2027-28	2028-29	2033-34
Deer Park 220 kV	209	Nil	Nil	Nil	Nil	20	95
Tyabb 220 kV	209	Nil	Nil	Nil	Nil	Nil	30
Rowville 220 kV area	210	Nil	Nil	Nil	Nil	Nil	55

Table 5 Pillar 2 – possible over-voltages under 2023 ESOO Central scenario, 90% 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.

Table 6 Pillar 2 – equivalent absorbing MVAr capacity required to bring all over-voltages within limits under 2023 ESOO Central scenario, 90% POE minimum demand forecast in the next 10 years

Critical site	High voltage limit (kV)	Equivalent absorbing reactive capacity (MVAr) to bring over-voltages within limits					
		2024-25	2025-26	2026-27	2027-28	2028-29	2033-34
South Morang 500 kV	525	15	Nil	Nil	90	215	215

2.2 Key assumptions and new information since the PSCR

Consistent with the requirements of the AER's RIT-T guidelines[12], AVP has adopted the inputs, assumptions and scenarios from the most recent 2023 IASR, except in circumstances where a new, omitted or varied input or assumption has been necessary. The sections below provide an update to Section 2.3 of the PSCR, and include new information or assumptions that have changed since the PSCR and have contributed to changes in quantum and location of the identified need and credible options to meet it. Key inputs and assumptions that do not influence the identified need, but are key to the cost benefit assessment are discussed in Chapter 4.

For the purposes of identifying the need, demand forecasts from only the 2023 ESOO Central scenario have been used. Other scenarios from the most recent 2023 IASR have been tested and weighted in the PADR modelling of option market benefits, which is discussed in Chapter 4.

2.2.1 System standards and voltage limitations

NER clauses S5.1.4 and S5.1a.4 require that AVP must plan and design its transmission system and equipment for voltage control to maintain system normal voltage within 10% of normal voltages; that is, under system normal conditions, both under- and over-voltage levels must be maintained within 10% or normal voltages. Short-term exceedances of this requirement are allowable under contingency events.

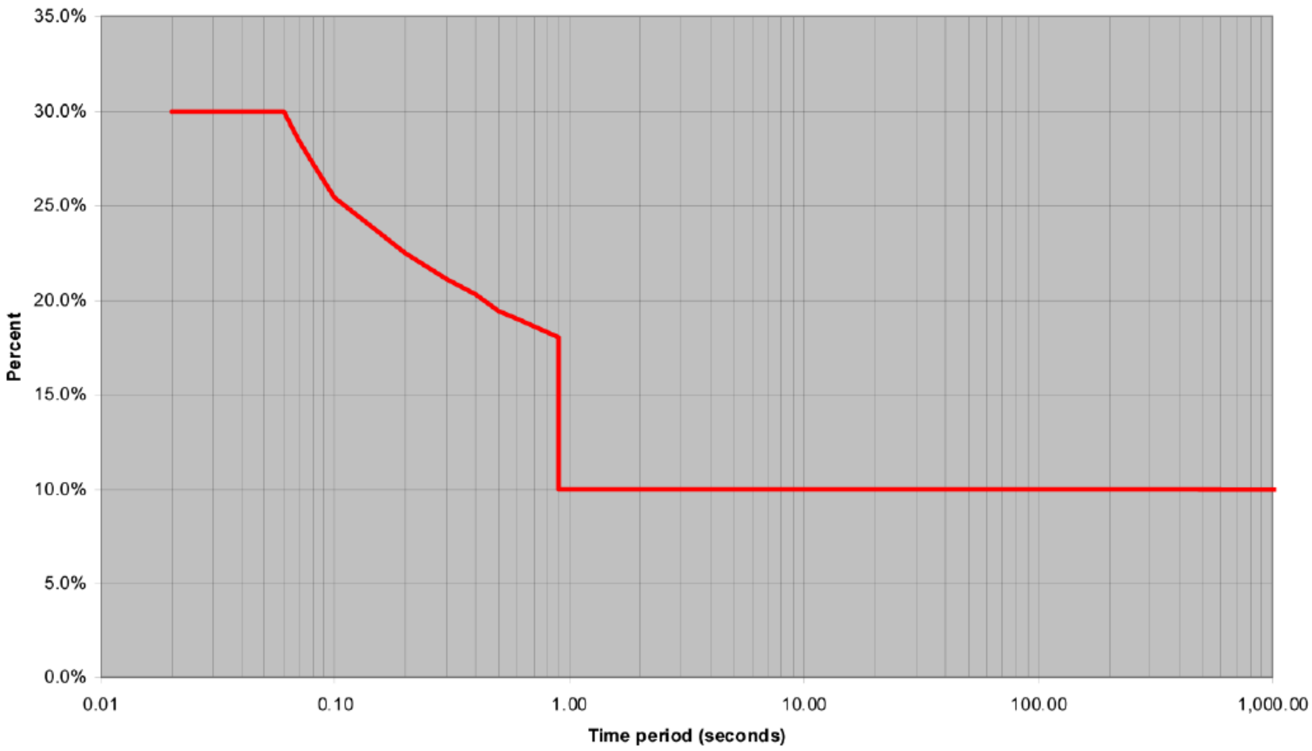
As a consequence of a credible contingency event, the voltage of supply at a connection point should not rise above its normal voltage by more than a given percentage of normal voltage for longer than the corresponding period shown in Figure 1.

In summary, this means that, among other requirements, over-voltages are allowed to rise to 130% of the normal voltage level for up to 60 milliseconds (ms) but must be managed within 10% of the connection point's normal voltage within 900 ms of a credible contingency event.

For under-voltages however, clause S5.1a.4 states that as a consequence of a contingency event, the voltage of supply at a connection point could fall to zero for any period of time. That said, operational measures, such as post-contingent load reduction, would typically be undertaken to restore voltages to within the system normal operating limits to prevent damage to electrical plant.

[12] 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.

Figure 1 Connection point over-voltage of supply requirements (NER figure S5.1a.1)



While the above NER standards must be met as a minimum, some locations within the DSN currently need to be managed to even tighter limits due to site-specific asset limitations and to manage downstream voltage stability. These tighter voltage limitations underpin AEMO's operational procedures for the Victorian DSN.

Existing over and under-voltage limitations at some relevant sites have been updated since the PSCR[13], for reasons noted in Table 7 and Table 8 below.

Table 7 Site specific over-voltage limitations

Location	Continuous voltage limit	Short-term voltage limit	Limitation description	Update from the PSCR
Keilor 500 kV	1.05 per unit of nominal voltage (525 kV)	1.07 per unit of nominal voltage (535 kV)	Keilor 500/220 kV transformer limitation	Post-contingent short-term high voltage limit upgrade has become a committed project since the PSCR, lifting the short-term limit from 1.05 per unit to 1.07 per unit of nominal voltage. See Section 2.2.8 for more information on this change.
South Morang 500 kV	1.05 per unit of nominal voltage (525 kV)	1.1 per unit of nominal voltage (550 kV)	South Morang 500/220 kV transformer and other switchgear limitation[14]	New critical site after increase to Keilor 500 kV short-term limit described above.

[13] See https://aemo.com.au/-/media/files/initiatives/metropolitan-melbourne-voltage-management-rit/metropolitan-melbourne-voltage-management-rit-t---pscr.pdf?la=en.

[14] AVP is aware of AusNet's RIT-T for maintaining reliable transmission network services at South Morang Terminal Station, which may replace the equipment that sets the high voltage limit at South Morang 500 kV. The PSCR for this RIT-T is available at: https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/about/regulatory-investment-test/2024/smts-gis-replacement-pscr_v1.pdf?rev=f8457e3fa8db47febf526f87e030d23c&hash=27D6F2B640A203632C6CD7E56B01694A.

Location	Continuous voltage limit	Short-term voltage limit	Limitation description	Update from the PSCR
Sydenham 500 kV	1.05 per unit of nominal voltage (525 kV)	1.1 per unit of nominal voltage (550 kV)	Sydenham switchgear limitation	Additional information not included in the PSCR
Rowville 220 kV area	1.036 per unit of nominal voltage (228 kV)	1.036 per unit of nominal voltage (228 kV)	Operational limit to maintain acceptable customer voltage. The terminal station equipment voltage ratings are much higher.	Additional information not included in the PSCR

Table 8 Site specific under-voltage limitations

Location	Continuous voltage limit	Short-term voltage limit [A]	Limitation description	Update from the PSCR
Deer Park 220 kV	0.95 per unit of nominal voltage (209 kV)	0.95 per unit of nominal voltage (209 kV)	Operational limit to manage downstream voltage stability	None
Tyabb 220 kV	0.95 per unit of nominal voltage (209 kV)	0.95 per unit of nominal voltage (209 kV)	Operational limit to manage downstream voltage stability	None
Rowville 220 kV area[B]	0.954 per unit of nominal voltage (210 kV)	0.954 per unit of nominal voltage (210 kV)	Operational limit to manage downstream voltage stability	None

A. Under-voltage limits are subject to customer adherence to power flow and power factor limits at the customer's supply point, and only apply while the power system is in a *secure operating state*.
B. This area consists of Rowville, Springvale, Malvern, Thomastown, Ringwood, Templestowe, Heathrow, Richmond and Brunswick on the 220 kV level. The limits provided are the most onerous limits for this area.

2.2.2 Regional maximum demand forecast

Identified Need Pillar 1 – the need to manage under-voltages – has been assessed using AEMO's regional maximum operational demand forecast from the 2023 ESOO Central scenario, consistent with the studies performed in identifying the need and credible options for the PSCR.

As shown in Figure 2, this scenario forecasts a steady increase in maximum operational demand over the next 10 years, largely driven by electrification of industries such as transport, and of residential and commercial gas substitution. As highlighted in the 2023 ESOO, maximum demand periods are forecast to frequently occur outside daylight hours.

Figure 3 shows simulated daily Victorian regional demand profiles, using the 2023 demand profile, for the forecast maximum demand days in 2023-24, 2027-28, and 2032-2033. This figure highlights the continuance of maximum demand periods around sunset.

Figure 2 Maximum operational demand forecast, Central scenario

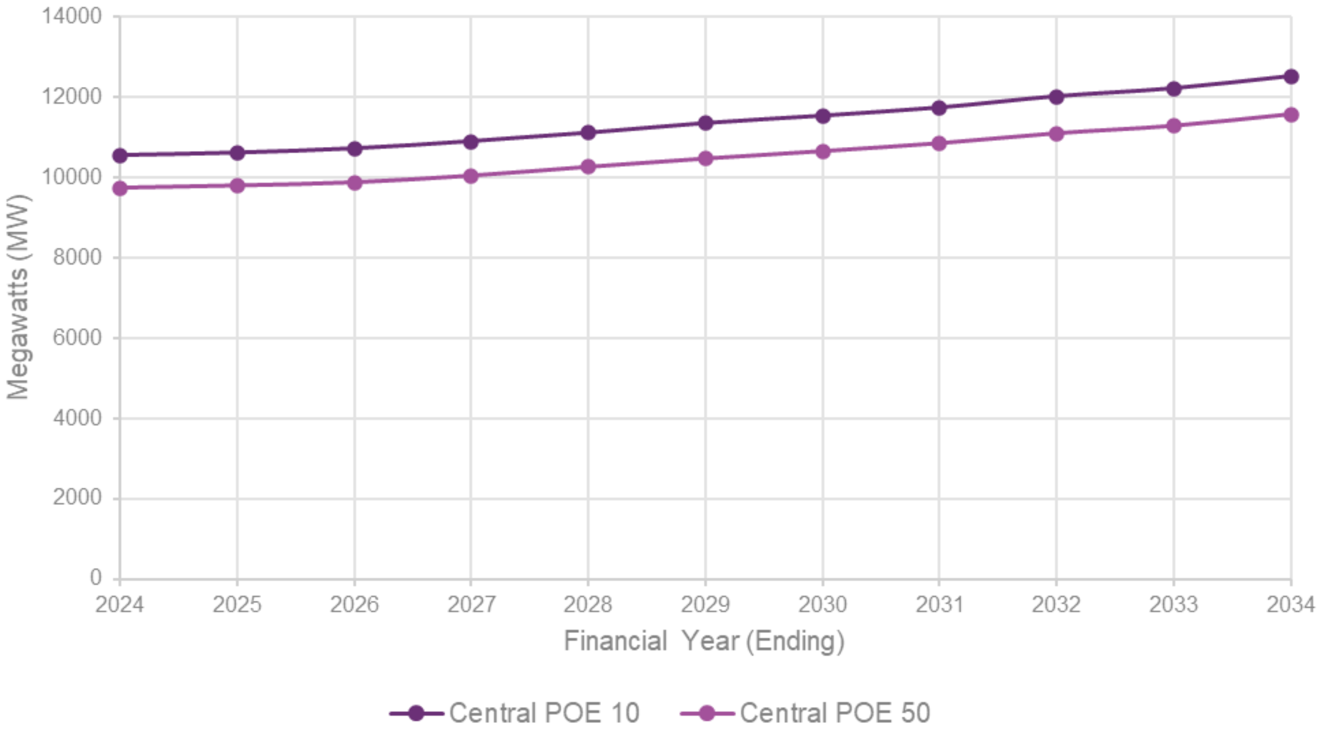
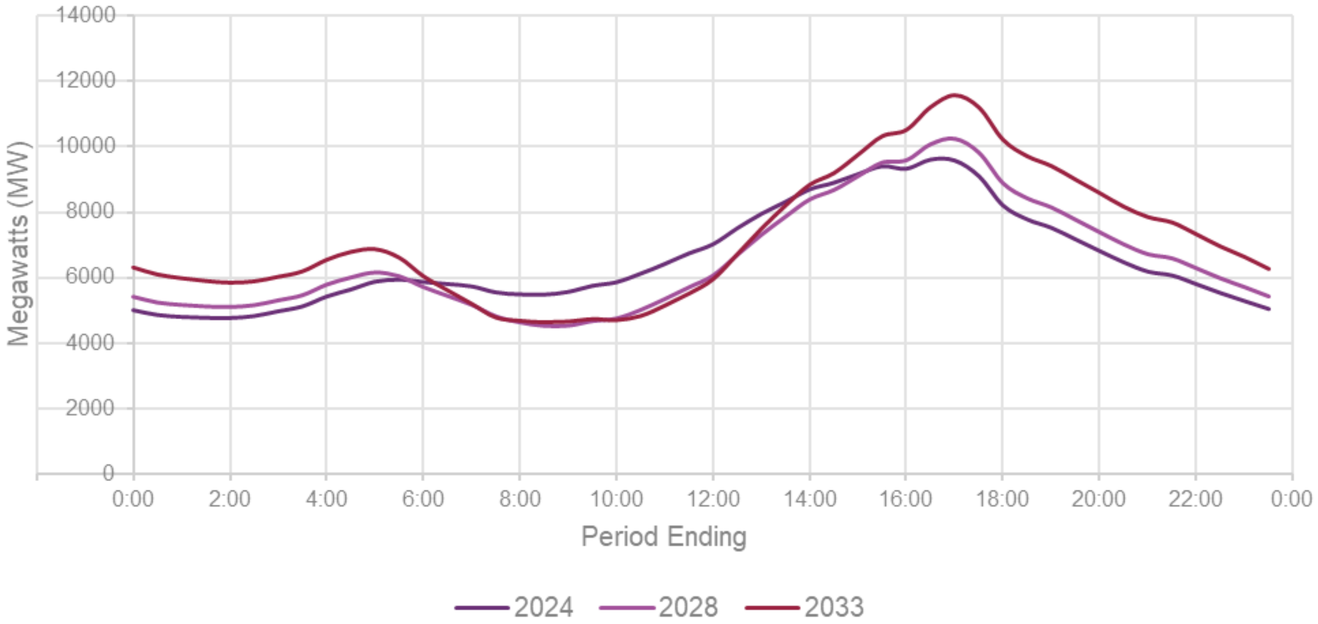


Figure 3 Forecast daily Victorian demand profile (FY2023) of maximum demand days in (FY ending) 2024, 2028, and 2033, Central scenario 50% POE



Notes: Period Ending given in Australian Eastern Standard Time.

2.2.3 Regional minimum demand forecast

Identified Need Pillar 2 – the need to manage over-voltages – has been assessed using AEMO's regional minimum operational demand forecast from the 2023 ESOO Central scenario, consistent with the studies performed in identifying the need and credible options for the PSCR.

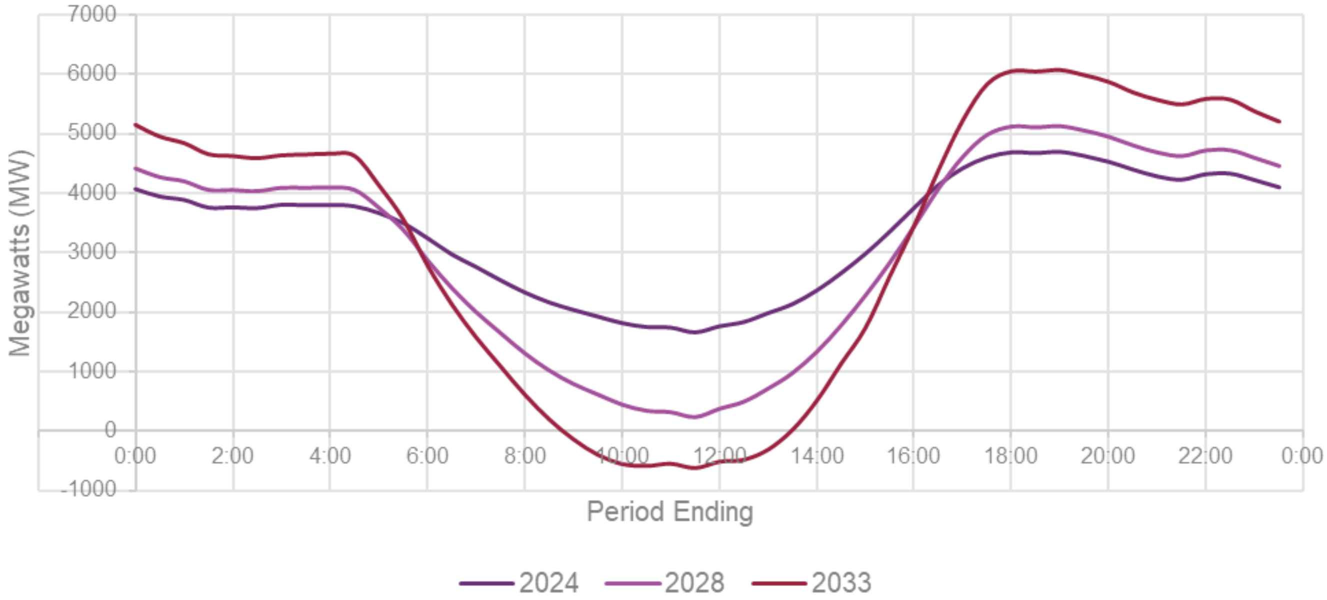
As shown in Figure 4, this scenario forecasts a significant reduction in Victoria's operational minimum demand and a shift to negative operational demand levels from 2029 onwards[15]. This reduction is predominantly driven by a continued forecast increase in distributed PV installations reducing operational demand in the middle of the day.

Figure 4 Minimum operational demand forecast

Figure 5 shows forecast daily Victorian regional operational demand profiles, using the 2023 demand profile, for the forecast minimum demand days in 2024, 2028, and 2033. This figure highlights the continuance of minimum operational demand periods in the middle of the day (as this is operational demand, it does not include the dispatch of market-based solutions such as battery energy storage systems (BESSs) that may take advantage of these low demand periods to charge.)

[15] The minimum operational demand forecasts represent uncontrolled or unconstrained demand, free of operational measures to constrain PV generation and market-based solutions that might increase operational demand in periods of excess supply (including coordinated storage and electric vehicle (EV) charging, scheduled loads such as pumping load, and demand response).

Figure 5 Forecast daily Victorian demand profile (2022-23) of minimum demand days in (FY ending) 2024, 2028, and 2033, Central scenario 50% POE



Notes: Period Ending given in Australian Eastern Standard Time.

2.2.4 Transmission connection point demand forecasts

Individual transmission connection point demand (for both active and reactive power) will have a material influence on the locations and size of the identified shortfalls in metropolitan Melbourne. Connection point maximum demand forecasts have been revised since the PSCR, and so have been used in this RIT-T assessment.

Maximum demand

For the PSCR, AVP preserved the connection point load profile from the most recent actual annual maximum demand period (18:00 on 17 January 2023), while scaling Victorian regional demand to match the 2023 ESOO maximum demand forecasts. Since the PSCR, AEMO developed coincident and non-coincident connection point forecasts for Victoria for both active and reactive power, and AVP used these forecasts for PADR assessments. The power factor at each transmission connection point was derived from the reactive power forecasts.

These coincident and non-coincident maximum operational demand forecasts for individual connection points in Victoria can be found in Attachment A – Maximum Demand Connection Point Forecast[16]. For this PADR, AVP has adopted these forecasts to:

- Improve how the 2023 ESOO regional maximum demand forecast is distributed across connection points in the Victorian DSN.
- Improve the modelled power factor for each connection point in the Victorian DSN.

The coincident connection point forecasts were used to establish maximum demand base cases, then these base cases were used to identify connection points in metropolitan Melbourne with under-voltage exceedances and the

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

corresponding maximum supportable demand for these connection points before these exceedances occur. See Section 5.3.3 for how these maximum supportable demand quantities have been applied in the PADR modelling. See Figure 6, Figure 7, and Figure 8 in Section 6.3.1 for the maximum supportable demand and the non-coincident maximum operational demand forecast annually across the next 10 years for each of the Pillar 1 critical sites.

Minimum demand

There has been no update to the connection point minimum demand forecasts since the PSCR. While there has been a more recent minimum demand event (approximately 13:30 on 31 December 2023), AVP preserved the connection point load profile used in minimum demand studies for the 2023 *Victorian Annual Planning Report* (VAPR) – this being the load profile from the annual minimum demand period for the 2023 VAPR (13:00 on 18 December 2022) – in scaling Victorian regional demand, to match the 2023 ESOO minimum demand forecasts. This is consistent with the PSCR studies.

Given that over-voltage challenges during minimum demand periods are due to low demand across the system rather than any particular connection point, AVP considers that adopting a different connection point load profile would result in immaterial changes to the identified need.

AVP used the distributed PV forecasts from the 2023 ESOO, and applied the following assumptions relevant to this voltage management RIT-T, consistent with the PSCR:

- Changes in underlying connection point demand (for both active and reactive power demand) for future annual minimum operational demand periods will remain relatively fixed.
- Distributed PV will contribute active power output only[17]

Due to the above assumptions, only the active power (megawatts (MW)) component of load is forecast to decrease in future annual minimum operational demand periods. Therefore, AVP preserved the reactive (MVAr) component of loads in Victoria from the actual annual minimum operational demand period of 2022 in scaling Victorian regional demand to the 2023 ESOO minimum operational demand forecasts.

2.2.5 Forecast of generation expansion, withdrawals, and dispatch pattern

In this PADR assessment, AVP has incorporated newly committed and anticipated projects listed in the latest May 2024 Generation Information update[18]. Changes that are expected to have a material effect on the voltage management support needs in metropolitan Melbourne are listed in 0.

Table 9 Anticipated or committed connection projects considered in determining size of identified need

Project Name	Type	Capacity	Full commercial use date	Update since PSCR
Ryan Corner Wind Farm	Wind farm	218 MW	Mar 2024	No change

[17] Provision of reactive power from distributed PV has been identified as a non-network option for this RIT-T.

[18] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. AVP will continue to monitor the progression of future connections and include all future committed and anticipated projects listed in any Generation Information Page update later than the May 2024 update in analysis for the PACR.

Project Name	Type	Capacity	Full commercial use date	Update since PSCR
LaTrobe Valley BESS	BESS	100 MW / 200 megawatt hours (MWh)	Jul 2024	Newly anticipated
Golden Plains Wind Farm East	Wind farm	756.4 MW	Aug 2025	No change
Rangebank BESS	BESS	200 MW / 400 MWh	Oct 2024	No change
Koorangie BESS	BESS	185 MW / 370 MWh	Apr 2025	Updated from anticipated to committed
Hawkesdale Wind Farm	Wind farm	96.6 MW	Apr 2024	No change
Melbourne Renewable Energy Hub – Side A	BESS	600 MW /1,600 MWh	Nov 2025	Updated from anticipated to committed
Terang BESS	BESS	101.5 MW / 200 MWh	Dec 2025	Newly anticipated
Gnarwarre BESS Facility	BESS	290 MW / 550 MWh	Jan 2026	No change. Not considered in the PSCR[A].
Wooreen BESS	BESS	350 MW / 1,400 MWh	Dec 2026	No change but was not considered in the PSCR[A].
Mortlake Battery	BESS	300 MW / 600 MWh	Mar 2027	Newly anticipated

A. Anticipated projects were excluded from the base case in the PCSR but have been included in the PADR base case. Including anticipated projects in the base case is consistent with the requirements of the AER's RIT-T guidelines (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).

Relevant generation withdrawal forecasts (including retirement of Yallourn Power Station in 2028) have not changed since the PSCR and are consistent with the latest IASR.

The dispatch assumptions described in the PSCR have been retained in this PADR, provided below in Table 10. Note that regarding dispatch assumptions for minimum demand (Pillar 2), Loy Yang units were prioritised for dispatch over other synchronous generation in Victoria due to them being the most effective synchronous units (except for gas) at alleviating Pillar 2 needs. Table 10 summarises the dispatch assumptions used for maximum demand and minimum demand studies, which are considered to have a material effect on the voltage management support needs in metropolitan Melbourne.

Table 10 Dispatch assumptions

	Maximum demand	Minimum demand
Grid-scale solar farms	Offline (no reactive support available) [A]	Online with output up to 50% of maximum capacity [B]
Wind farms	Online with output up to 30% of maximum capacity [C]	Online with 0 MW output
BESSs	Online with 0 MW charge or discharge [D]	Online with 0 MW charge or discharge [E]
Synchronous generation (coal, gas, and hydro)	Online with MW output up to maximum rated capacity.	Online if able to be dispatched with MW output above minimum stable operating levels, otherwise offline.

A. Given that maximum demand is forecast to continue to occur in the early evening, around sunset, studies assumed that solar farms would be offline.
B. In line with expected capacity factors during daytime minimum demand periods as derived from AEMO's 2023 ESOO market modelling solar output profiles, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.
C. In line with expected capacity factors during evening maximum demand periods as derived from AEMO's 2023 ESOO market modelling wind output profiles
D. Based on the average of all solutions and iterations in the ESOO market modelling for BESS dispatch during peak demand periods.
E. BESSs have been assumed with 0 MW output, because BESS charging cannot be guaranteed at times of minimum demand. Making this assumption allows BESS charging to be reserved as a non-network credible option or as an operational measure to use if needed.

AVP has also considered different operating behaviours of battery energy storage systems (BESS) as the BESS fleet grows in accordance with the scenario specific Draft 2024 ISP capacity projections. The impact of different operating behaviours has been explored in a sensitivity study that assesses the identified need and credible options against a future where the BESS fleet charges at 25% of its charging capacity, to investigate the robustness of credible options and the proposed preferred option of this RIT-T. See Section 6.5 for outcomes of this and other sensitivities.

AVP also notes that there are a number of connection projects that are publicly announced and/or progressing connection applications in areas that would effectively contribute to meeting the identified need of this RIT-T (see Table 12 and Table 13 in Section 3.1 below for a list of such areas for each Pillar), but do not satisfy all RIT-T criteria[19] to be considered anticipated or committed. AVP has considered the impact of these projects in sensitivity studies, to investigate the robustness of credible options and the proposed preferred option of this RIT-T. See Section 6.5 for outcomes of this and other sensitivities.

2.2.6 Reactive power support from inverter-based resources (IBR)

Large-scale inverter-based resources

AVP has considered reactive power support availability from large IBR consistent with assumptions in the PSCR – in line with respective performance standards and dispatch levels noted in Section 2.2.5. This reactive support consistent with respective performance standards and dispatch levels has been assumed as available where generation has been assumed online as shown in Table 10, or unavailable where generation has been assumed offline as in Table 10. Reactive support from future, uncommitted, generation and storage projects was not considered, as these connections are not yet guaranteed.

See Section 6.5 for outcomes of a sensitivity study that explored the impact on the identified need and subsequently credible options of reactive support from future connections that are currently neither committed nor anticipated.

Distributed PV installations

As mentioned in Section 2.2.4 above, in calculating connection point reactive power demand, AVP assumed that distributed PV installations would not provide any reactive power support at transmission level. 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 to an estimated 75-80%[20], the impact of a volt-var response delivered at 240 volts (V) has on transmission connection points is still unknown. AVP has therefore taken a conservative approach, assuming no support from distributed PV. AVP will continue to monitor progress in this space, and assumptions will be updated in the PACR if appropriate.

[19] The criteria are included the RIT-T Glossary, at https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

[20] See *Compliance of Distributed Energy Resources with Technical Settings: Update*, Section 2.2, at https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6.

2.2.7 Aging equipment

Services agreements expiring within the next 10 years have been considered in this RIT-T, specifically, a reactive power services agreement relating to 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.

2.2.8 Operational measures

The operational measures outlined in this section are considered as potential short-term mechanisms to manage transmission system voltages. These measures may need to be relied on to manage voltages in metropolitan Melbourne when required, until such time as investment in reactive support is economically feasible[21] to replace them. Some of these measures are most appropriately used as a last resort in rare emergency situations that are not forecast or have a probability of occurrence that is too low to justify investment.

More standard operational measures, such as transformer tapping, the use of available reactive plant, reactive capabilities in line with generator connection agreements and existing contracts with generators or NSPs for voltage support have all been assumed as available in this PADR assessment.

500 kV line de-energisation for minimum demand reactive needs

The level of absorbing reactive power compensation required to meet the identified need was calculated assuming no de-energisation of single 500 kV lines. De-energisation of one or more 500 kV lines may result in other adverse impacts for the power system and may only be suitable for managing voltages at the discretion of Operations teams at the time of the event.

Distributed PV curtailment

Refer to the PSCR for assumptions regarding distributed PV curtailment.

Keilor over-voltage control scheme

The Keilor 500 kV over-voltage protection scheme is an automatic tripping scheme to manage voltages at Keilor 500 kV. When this scheme is operationally available, the Keilor 500 kV short-term high voltage limit increases from 525 kV to 535 kV. Currently, due to the need for manual oversight of this scheme, it is used as an emergency management measure, operationally unavailable for normal operating conditions and reserved for extreme and unexpected operating conditions. Since the PSCR, an upgrade to make this scheme always operationally available has been progressed, and is scheduled to be completed by spring 2024. The cost of this upgrade is well below the RIT-T cost threshold so has been able to progress without the need for a RIT-T. The committed upgrade will result in a permanent increase in the Keilor 500 kV short-term rating to 535 kV. This increase in short-term rating

[21] As outlined in NER 5.15A.1, the purpose of the 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 market. Since this RIT-T is not being assessed as a reliability corrective action RIT-T, the preferred option must also have a positive net economic benefit to be considered economically justified.

has been included in this PADR and contributed to some of the changes in quantum and location of the identified need highlighted in Table 7.

Status of capacitor banks installed within distribution networks

The reactive power loads being supplied through the DSN will change based on assumptions for capacitors installed within the distribution network. Unlike capacitors installed in the transmission network, which would already be switched on if low voltage issues in the DSN were observed, or switched off if high voltage issues in the DSN were observed, some distribution network connected capacitors may be switched differently during these periods.

For maximum demand conditions studied, distribution voltages were observed as reaching low levels as well as transmission voltages, hence these distribution capacitors were assumed to be online.

For minimum demand conditions studied, distribution voltages were not observed as reaching low levels and therefore these distribution capacitors were assumed to be offline.

These assumptions are consistent with the PSCR.

2.2.9 Network support and control ancillary services (NSCAS) gap

The 2023 NSCAS report, delivered by AEMO (as the system planner) in December 2023, identified a reliability and security ancillary services (RSAS) gap for thermal overloading and voltage control following credible contingencies on the 220 kV network near Deer Park from 2023-24 onward[22].

AVP is addressing the voltage control component of this gap through this Metropolitan Melbourne Voltage Management RIT-T.

A RIT-T is presently underway for the thermal overloading component of this gap, with the PSCR planned to be published later this year.

[22] See Chapter 2.5 of https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-nscas-report.pdf?la=en.

3 Credible options included in the RIT-T analysis

Analysis has considered all credible network and non-network options to address the identified need. The options described cover a range of potential solution sizes, technologies, locations, and timings. These combinations have been refined to identify those likely to maximise the net market benefits through a full cost-benefit assessment.

3.1 Types of potential options

As described in Chapter 3 of the PSCR, a credible network option in this RIT-T should have the capability to:

- maintain voltage stability; and
- maintain voltages within limits or, in the case of both over- and under-voltages, widen existing operational and/or site-specific equipment limits such that operating at voltages up to the requirements outlined in NER clauses S5.1.4 and S5.1a.4 is made possible.

Following the PSCR, AVP sought submissions from providers of potential non-network options with these capabilities. AVP received submissions, and the assessment of credible options has therefore focused on combinations of both network and non-network assets.

Technically feasible network and non-network options that have been considered in this PADR are summarised in Table 11.

Information on the characteristics and considerations of these options is presented further in this chapter. While there are many options that can be considered technically capable of contributing to meeting the identified need, AVP has undertaken initial screening of these options to refine the list to those it considers likely to deliver positive net market benefits and be sufficiently cost-competitive to plausibly become part of the preferred option.

The options that AVP considers both technically and economically feasible are detailed in Section 3.5. Section 3.8 details other credible options that AVP considered in this RIT-T but assessed as not technically or economically feasible for further consideration beyond the screening process.

Overall, combinations of these network and/or non-network options at varying locations, voltage levels, and of varying technologies, capacities, and connection arrangements are needed to form credible options that meet the identified need.

The identification and refinement of these credible options is discussed in the following sections.

Table 11 Short-listed feasible network and non-network options assessed to meet the identified need

Need	Type of option	High-level description of option to address the need
Identified Need Pillar 1 (Under-voltages during high demand)	Network option	Investment sufficient to allow transmission system under-voltages to be managed, such as additional generating reactive support in the form of capacitors or dynamic reactive plant such as synchronous condensers, STATCOMs or SVCs.
	Network option	Investment to widen existing voltage limits at sites to levels stipulated in NER clauses S5.1.4 and S5.1a.4, such as replacing aging assets with uprated equipment, increasing redundancy to remove critical voltage stability constraints.
	Non-network option	Further BESS grid connections in the right locations with available reactive support.
	Non-network option	Demand side participation in the form of voluntary load reduction.
	Non-network option	Pre- or post-contingent load reduction control schemes – these schemes would need to strategically comprise load blocks that relieve low voltages where there is a risk of limits being exceeded.
	Network option	Other control schemes initiated by AVP to enhance DSN performance.
Identified Need Pillar 2 (Over-voltages during low demand)	Network option	Investment sufficient to allow transmission system over-voltages to be managed, such as additional absorbing reactive support (in the form of reactors or dynamic reactive plant such as synchronous condensers, STATCOMs or SVCs).
	Network option	Investment to widen existing voltage limits (for example, to upgrade existing transmission assets, such as 500/220 kV transformers that currently limit over-voltages at a number of 500 kV locations) to levels below those stipulated in NER clauses S5.1.4 and S5.1a.4).
	Non-network option	Further BESS grid connections in the right locations with available reactive support.
	Non-network option	Demand side participation in the form of increasing load or curtailing distributed PV/CER.
	Network option	Other control schemes initiated by AVP to enhance DSN performance.

Location and voltage level

The more electrically separated network and non-network options are from the critical sites identified in Section 2.1, the less effective they become. Electrical separation can occur if the network or non-network option is located away from the terminal station in need of voltage management support, or even if it is located at the terminal station but at a voltage level different to that which needs support (in the latter case, the local transformers would be the cause of electrical separation). This electrical separation becomes more pronounced under credible contingency events, particularly if the credible contingency is loss of the single element that connects the network or non-network option to the site that requires support.

While sites that are electrically separated are less effective at addressing the identified need, it may be less costly or more practical to build there than at sites that are more effective at addressing the identified need. This is therefore a trade-off that this PADR will explore in assessing options and proposing a preferred option.

Studies conducted for this PADR have built on work undertaken for the PSCR, to test and refine the equivalent effectiveness of options at different sites under a number of study cases with different system conditions. Where for the PSCR, the solution sites' percentage effectiveness at addressing the critical site's gap was based on a single study snapshot, the credible solution sites (based on technical merit) and their percentage effectiveness have been updated for this PADR based on a suite of snapshots with different load levels and generator dispatch outcomes.

For all sites tested in this PADR where network or non-network options may feasibly be located, the equivalent effectiveness in managing voltages at a critical site is reported below.

Identified Need Pillar 1 (need to manage under-voltages within limits)

Table 12 shows the potential terminal stations and accompanying voltage levels where additional generating reactive power support or load reduction may be reasonably effective at addressing Identified Need Pillar 1, for any one or more of the critical sites needing voltage management support.

Table 12 Possible solution sites to address largest forecast generating reactive shortfall in next 10 years

Solution site	Solution site's effectiveness at addressing shortfall at the critical sites[A]		
	Critical site: Deer Park 220 kV	Critical site: Tyabb 220 kV	Critical site: Rowville B 220 kV
Deer Park 66 kV	114%	0%	0%
Deer Park 220 kV	100%	0%	29%
Geelong 220 kV	13%	0%	0%
Geelong 66 kV	12%	0%	0%
Moorabool 220 kV	9%	0%	0%
Tyabb 66 kV	2%	103%	0%
Tyabb 220 kV	2%	100%	0%
Cranbourne 220 kV	2%	82%	0%
Malvern 66 kV	2%	0%	105%
Springvale 220 kV	2%	0%	102%
Malvern 220 kV	2%	0%	101%
Springvale A 66 kV	2%	0%	100%
Rowville B 220 kV	2%	0%	100%
Springvale B 66 kV A	2%	0%	100%
Ringwood 66 kV	2%	0%	95%
Ringwood 220 kV	2%	0%	91%
Templestowe 66 kV	2%	0%	88%
Templestowe 220 kV	2%	0%	83%
Thomastown 220 kV C	2%	0%	73%
Thomastown 66 kV	2%	0%	68%
Thomastown 220 kV A	2%	0%	66%
Brunswick 220 kV	2%	0%	66%
South Morang 220 kV	2%	0%	62%

A. A % effectiveness of greater than 100% for any solution site indicates that addressing the gap here may be more effective than addressing it at the identified transmission level critical site.

Identified Need Pillar 2 (need to manage over-voltages within limits)

Table 13 shows the potential terminal stations and accompanying voltage levels where additional absorbing reactive power support or equivalent may be reasonably effective at addressing Identified Need Pillar 2, for South Morang 500 kV (being the most onerous critical site).

Table 13 Possible solution sites to address largest forecast absorbing reactive shortfall in next 10 years

Solution site	Solution site's effectiveness at addressing shortfall at the critical site
	Critical site: South Morang 500 kV[A]
South Morang 500 kV	100%
Hazelwood 500 kV	90%
Rowville 500 kV	85%
Keilor 500 kV	81%
Cranbourne 500 kV	81%
South Morang 330 kV	80%
Sydenham 500 kV	76%
South Morang 220 kV	67%
Thomastown 220 kV	63%
West Melbourne 220 kV	62%
Altona 220 kV	62%
Brooklyn 220 kV	62%
Keilor 220 kV	60%
Templestowe 220 kV	59%
Hazelwood 220 kV	58%
Malvern 220 kV	58%
Rowville 220 kV	57%
Deer Park 220 kV	56%
Brunswick 220 kV	51%
Yallourn 220 kV	50%
East Rowville 220 kV	33%
Moorabool 500 kV	33%
Geelong 220 kV	29%
Moorabool 220 kV	26%
Tyabb 220 kV	18%
Cranbourne 220 kV	17%

A. Other critical sites included in Table 5 sit behind South Morang 500 kV and their voltage exceedances are resolved when addressing South Morang 500 kV as the critical site. For this reason, the percentage effectiveness of solution sites is only included for addressing South Morang 500 kV voltage exceedances.

3.2 Land, environmental and social considerations

AVP undertook desktop investigations since the PSCR to identify and understand land assembly options, environment, planning and social constraints for credible solution sites and identify relevant cost factors to achieve planning and environment regulatory obligations for credible options.

A desktop review of technically effective solution sites included in Section 3.1 indicated which of these has sufficient (brownfield) land capable of accommodating new network options (such as capacitors, reactors, and dynamic plant such as SVCs) and their necessary connection arrangements. Standard connection arrangements assumed for this analysis are described in Section 3.3.2 below. This review helped identify the credible solution sites considering technical effectiveness at meeting the identified need while reducing the need for land in greenfield areas for new infrastructure. This review also identified any additional costs of new station arrangements or equipment needed to connect a credible option. See Section 3.6 for cost estimates of the credible options described in Section 3.5. See Section 5.4 for more information on the cost estimate methodology applied in this PADR.

As part of this desktop assessment, AVP also estimated the maximum hostable MVAr investment in network options for each credible solution site, and accordingly developed the credible options described in Section 3.5 based on this shortlist of candidate solution sites. AVP notes that while a shortlist of sites for new network options has been presented as part of the credible options described in Section 3.5, other sites with similar technical effectiveness and similar ability to host new network options could form part of the credible options instead. Therefore, if any complexities arise from further analysis for the PACR of these shortlisted sites, other sites with good technical effectiveness from Section 3.1 may be selected instead as part of the credible options and the final preferred option.

The siting of capacitors and reactors should carefully consider ways to minimise potential environmental and social impacts. There may be other requirements that may need to be considered as part of planning and environment approval processes. AVP has estimated costs of planning and environmental approval processes in Section 3.6.

The credible options are not anticipated to have the potential to cause significant impact to communities as credible solution sites operate in parts of metropolitan Melbourne with limited interface to sensitive land uses.

The analysis contained in this PADR is based on desktop available information only, is subject to change, and has not been informed by any field investigations, community or landholder engagement, or the specific requirements of any planning and environmental approval processes relevant at the time. Further detailed studies assessing the potential environmental and planning impacts will form part of the relevant planning and approval processes for the credible options.

For non-network options considered in this PADR, AVP has assumed each option has achieved land acquisition and environmental and planning approvals necessary to permit the start of construction. If this assumption does not hold, the non-network option costs will be higher than assumed in this PADR.

3.3 Network options assessed

3.3.1 Widening operational limits

Keilor 500 kV high voltage limits

Bringing forward the replacement projects for Keilor 500/220 kV transformers to increase their continuous voltage capability when voltage management support is needed was considered a credible option in the PSCR, on the basis that AVP would engage with AusNet Services regarding:

- Its plans for retiring and replacing the Keilor No.4 750 megavolt amperes (MVA) 500/220 kV transformer in 2028.

- The feasibility of bringing forward the replacement of the remaining Keilor 500/220 kV transformers that limit the upper voltage limit at Keilor 500 kV to 1.05 per unit of the nominal voltage (500 kV) – that is, to 525 kV.

Due to the recent commitment to upgrade the Keilor 500 kV high voltage limits by spring this year, bringing forward this transformer replacement project no longer addresses the voltage management need identified in this PADR. See Section 2.2.8 for more information on the over-voltage control scheme upgrade and Section 2.2.1 for the new limit that Keilor 500 kV will be able to operate to.

Deer Park 220 kV low voltage limits

Based on feedback from the PSCR, AVP considered the feasibility of a paper uprate of the Deer Park 220 kV low voltage limit to manage voltages during high demand periods at Deer Park 220 kV. The existing low voltage limit of 210 kV was established to ensure voltage stability downstream of Deer Park 220 kV (that is, in the distribution network connected at Deer Park Terminal Station (DPTS)). A paper uprate would mean a change to this limit without any physical upgrades of infrastructure, and is applicable when power system conditions have changed such that this downstream voltage stability can be maintained at even lower Deer Park 220 kV voltages.

AVP conducted voltage stability assessments and engaged with relevant NSPs to determine what an appropriate revised limit would be, based on how low the voltage can go before the system is no longer secure. AVP determined that the Deer Park low voltage limit is currently limited due to a credible loss of a Deer Park 220/66 kV transformer, and it may only be upgraded if the existing transfer capacity through the Deer Park 220/66 kV transformers is also upgraded in line with the options presented in the 2023 Transmission Connection Planning Report (TCPR). The proposed revised low voltage limit associated with this option following commitment of a Deer Park 220/66 kV upgrade is 198 kV. CitiPower/Powercor is currently undertaking pre-feasibility studies to assess options for the upgrade of the transfer capacity through the Deer Park 220/66 kV and will work with AVP to progress a RIT-T if necessary. Given a Deer Park 220/66 kV upgrade is currently not committed, AVP does not consider this paper uprate as a credible option in this PADR, and will provide an update in the PACR if required. In the event a Deer Park low voltage limit paper uprate becomes feasible, it would likely form part of the preferred option of this RIT-T.

AVP only considered a paper uprate of 220 kV low voltage limits for Deer Park because Deer Park voltage needs are localised. Other Pillar 1 critical sites (Tyabb 220 kV and Rowville 220 kV areas) represent a voltage management need for the broader eastern metropolitan Melbourne network, and therefore upgrading the low voltage limit at these specific sites will not defer the need for additional investment.

3.3.2 Installing additional reactive compensation capability

Technology type

Capacitors, reactors, and dynamic-type reactive plant can be used to meet the identified need. Dynamic plant includes SVCs, synchronous condensers, and any other plant able to provide continuously varying reactive power support.

Dynamic reactive plant is more expensive than capacitors or reactors (see Section 3.6 for a comparison of costs of individual equipment), but can provide benefits that capacitors and reactors cannot, such as improving system strength. Dynamic plant typically also offers continuously varying reactive power output, whereas capacitors and reactors provide discrete reactive output amounts. It is a common industry practice to maintain a reasonable amount of dynamic reactive plant in a highly compensated network (that is, a network like the DSN with a significant number of reactors and capacitors) to manage operational issues such as large step voltage changes following switching of large reactors or capacitors.

While the benefits of dynamic reactive plant of meeting both Pillar 1 and Pillar 2 needs are the only benefits that have been explored in this PADR, AVP will assess whether other benefits associated with their provision of system strength and continuously varying reactive output should be considered in the PACR.

Standard reactive plant sizes (MVAr)

A given reactive power shortfall can be met using a few high MVAr capacity reactive plant, or numerous low MVAr capacity reactive plant. The use of high MVAr capacity plant is typically more cost-effective than the use of low MVAr capacity plant if only considering system normal conditions. However, considering operational issues associated with switching high MVAr capacity plant, such as large step voltage changes, and the need for maintenance, the MVAr capacity of reactive plant needs to be carefully selected to achieve the most cost -effective outcome to meet the identified need.

In this PADR, the following have been considered as the possible capacities for capacitors and reactors for the purpose of developing cost estimates for the network options, considering an assessment of the maximum allowable reactive plant sizes to stay within step voltage change requirements[23]:

- 50 MVAr at 66 kV.
- 100 MVAr at 220 kV.
- 100, 150, and 200 MVAr at 500 kV.

The following have been considered as possible capacities for dynamic reactive plant such as SVCs and synchronous condensers:

- ±100, ±150, and ±200 MVAr at 220 kV.
- ±100, ±150, and ±200 MVAr at 500 kV.

These capacities have been selected to largely align with existing or retired reactive plant in the DSN, given certainty on their technical feasibility, as well as known voltage step change limitations associated with large capacity reactors and capacitors. Other capacities may be assessed in the PACR if proven beneficial, and if proven possible based on more rigorous step voltage change analysis.

Connection arrangements

The standard arrangement for connecting capacitors or reactors to support voltage levels at terminal stations is a single switched arrangement, where the capacitor or reactor is connected to a bus with a single circuit breaker. AVP considers this standard arrangement to be the most efficient and it has therefore been assumed for capacitor or reactor options assessed in this PADR.

[23] Requirements for voltage fluctuation are defined by NER S5.1a.5 and refer to Table 1 of Standard AS/NZS 61000.3.7:2001. To facilitate application, NSPs must establish "planning levels" for their networks as provided for in the Australian Standard.

3.4 Non-network options assessed

The PSCR listed three alternative non-network options that may meet the identified need:

- Demand response and decentralised storage.
- Additional reactive power support from grid-connected generators and BESS beyond that provided as part of the conditions for connection (see NER S5.2.5.1)[24].
- Distributed PV reactive power support.

More information on the requirements of these three types of options is included in Section 3.3 of the PSCR.

AVP received confidential submissions to the PSCR from two potential non-network service providers, and subsequently considered these in forming the credible options tested in this PADR.

AVP also welcomes further submissions of potential non-network options to meet the identified need, to be considered in the PACR.

3.5 Option portfolios assessed

Credible option portfolios for additional voltage management support that have been considered have consisted of a number of combinations of any one or more of the following network and non-network options:

- Static reactive plant such as capacitors (+) and reactors (-).
- Dynamic reactive plant such as SVCs (±).
- Upgrades to existing voltage limits.
- Non-network voltage management services such as:
  - Reactive generating and absorbing capability (±).
  - Demand response (±).

As noted in the PSCR, there are a large number of possible location combinations for the options above, given that investment in reactive support does not necessarily need to occur at the direct sites where the voltage management issues have been identified.

In this PADR, AVP has further refined the credible locations for investment from those included in Section 3.1 of the PSCR, based on technical merit, to those included in Table 12 and Table 13, and then conducted a detailed site assessment to further shortlist the preferred candidates.

AVP also welcomed submissions to the PSCR and considered the locations proposed for non-network options in this shortlist.

AVP then developed a list of credible options that underwent rigorous testing to determine a proposed preferred option that meets both pillars of the identified need.

[24] See https://energy-rules.aemc.gov.au/ner/572/447081#S5.2.5.1.

3.5.1 Credible options

Option 1 – Portfolio of 220 kV capacitors and reactors

Option 1 consists of shunt capacitors at Deer Park, Malvern, and Tyabb and shunt reactors distributed across South Morang, Thomastown, West Melbourne, Altona, Brooklyn, and Keilor, all on the 220 kV level and up to the optimal MVAr capacity identified in Section 6.3.

These sites were selected in line with locations that most effectively address the identified need and considering land, environmental and social constraints as discussed earlier in this chapter. While addressing the location with the greatest voltage exceedance and hence greatest voltage management shortfall, installing reactors across various sites also results in an outcome that is more robust to changes in network conditions, and will assist voltages in areas other than South Morang.

This option only consists of individual capacitor and reactor sizes of 100 MVAr, based on standard reactive plant sizes described above, known limitations regarding voltage step change requirements, and other known operational limitations with large capacitor step sizes. They are all assumed with a single circuit breaker connection arrangement.

See Section 6.3 for the optimal overall MVAr capacity, timing, and staging of individual components, which was tested as part of the cost benefit assessment, and for the estimated capital cost, and the gross and net market benefits accrued with this option.

Option 2 – Portfolio of 220 kV capacitors and reactors and non-network BESS voltage management services in eastern metropolitan Melbourne

Option 2 consists of shunt capacitors at Deer Park, Malvern and Tyabb and shunt reactors distributed across South Morang, Thomastown, West Melbourne, Altona, Brooklyn, and Keilor, all on the 220 kV level and up to the optimal MVAr capacity identified in Section 6.3, plus a non-network BESS service in eastern metropolitan Melbourne that provides both generating and absorbing reactive power capabilities.

The sites were selected in line with locations that most effectively address the identified need and considering land, environmental and social constraints as discussed earlier in this chapter. While addressing the location with the greatest voltage exceedance and hence greatest voltage management shortfall, installing reactors across various sites and contracting an additional reactive non-network service also results in an outcome that is more robust to changes in network conditions, and will assist voltages in areas other than South Morang.

This option consists of individual capacitor and reactor sizes of 100 MVAr only, based on standard reactive plant sizes described above, known limitations regarding voltage step change requirements, and other known operational limitations with large capacitor step sizes. They are all assumed with a single circuit breaker connection arrangement.

The non-network voltage management service considered in this option portfolio reduces the total network MVAr investment required and provides diversity of location (resulting in greater option robustness) and dynamic voltage support (resulting in smoother voltage adjustments) compared with the equivalent portfolio with only network options (Option 1).

See Section 6.3 for the optimal overall MVAr capacity, timing, and staging of individual components, which was tested as part of the cost benefit assessment, and for the estimated capital cost, and gross and net market benefits accrued with this option.

Option 3 – Portfolio of 220 kV capacitors and non-network BESS voltage management services at Deer Park 220 kV

Option 3 consists of shunt capacitors at Deer Park, Malvern and Tyabb and shunt reactors distributed across South Morang, Thomastown, West Melbourne, Altona, Brooklyn, and Keilor, all on the 220 kV level and up to the optimal MVAr capacity identified in Section 6.3, plus a non-network BESS service at Deer Park 220kV that provides both generating and absorbing reactive power capabilities.

The sites were selected in line with locations that most effectively address the identified need and considering land, environmental and social constraints as discussed earlier in this chapter.

This option consists of individual capacitor and reactor sizes of 100 MVAr only, based on standard reactive plant sizes described above, known limitations regarding voltage step change requirements, and other known operational limitations with large capacitor step sizes. They are all assumed with a single circuit breaker connection arrangement.

The non-network voltage management service considered in this option portfolio reduces the total network MVAr investment required compared with the equivalent portfolio with only network options (Option 1), and provides diversity of location (resulting in greater option robustness) and dynamic voltage support (resulting in smoother voltage adjustments).

See Section 6.3 for the optimal overall MVAr capacity, timing, and staging of individual components, which was tested as part of the cost benefit assessment, and for the estimated capital cost, and gross and net market benefits accrued with this option.

Option 4 – Option 1 plus the displacement of capacitors and reactors with one SVC

Option 4 consists of:

- Shunt reactors on the 220 kV level distributed across South Morang, Thomastown, West Melbourne, Altona, Brooklyn, and Keilor up to the optimal MVAr capacity identified in Section 6.3.
- Shunt capacitors at Deer Park and Tyabb 220 kV.
- One 150 MVAr SVC at Malvern 220 kV.

This option explores whether there is a net benefit to displacing capacitors and reactors with a single piece of equipment with both generating and absorbing reactive capability (in this example an SVC), where the SVC considered reduces the overall MVAr capacity investment needed to address both pillars compared with Option 1 above.

AVP tested a number of SVC sizes (in line with standard sizes included in Section 3.3.2) across a number of sites that are effective at addressing both pillars (in line with Table 12 and Table 13 in Section 3.1) and found that a 150 MVAr SVC at Malvern 220 kV is most effective at displacing both reactors and capacitors. See Section 6.3 for the optimal overall MVAr capacity, timing, and staging of individual components considering this SVC, which was tested as part of the cost benefit assessment, and for the estimated capital cost, and gross and net market benefits accrued with this option.

3.6 Cost estimates of credible options assessed

Class 5A (+/- 30%) cost estimates for individual equipment that the above network and non-network options are comprised of are presented in Table 14. These have been developed using the AEMO 2023 Transmission Cost Database (TCD) with appropriately set TCD known and unknown risk allowances. The costs also consider outcomes of individual site assessments to identify individual site constraints and complexities, and are based on standard capacities of reactive power plant and standard connection arrangements described in Section 3.3.2. Costs are presented in real 2023 dollars.

Overall investment costs for the different investment sizes tested for each credible option presented in Section 3.5 are included in Chapter 5, alongside the gross and net market benefits provided by each of them.

Table 14 Cost estimates of credible options' individual equipment

Component Description	Estimated capital cost ($M)
Options that contribute to Pillar 1 identified need only	
220 kV 100 MVAr shunt capacitor at Deer Park	6.93
220 kV 100 MVAr shunt capacitor at Malvern	6.39
220 kV 100 MVAr shunt capacitor at Tyabb	6.39
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 / Keilor	8.62
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	268.8[A,B]
220 kV 150 MVAr SVC at Malvern	33.08

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.

Operating and maintenance costs are in addition to the capital costs shown in Table 14, and were:

- For network options, estimated as 1% of the capital costs, aligned with the 2023 *Transmission Expansion Options Report* (TEOR)[25].
- 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.

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

Anticipated lead times are 18-24 months for capacitors and reactors, and 18-36 months for SVCs. Lead times for non-network generator and BESS options are aligned with the lead times specified in the 2024 ISP Inputs and Assumptions workbook.

3.7 Material inter-network impact

Neither the reactor, capacitor, nor non-network options have material inter-network impact, since they do not materially impact interconnector limits. See Section 3.3.4 of the PSCR for more information on what qualifies options as having a material inter-network impact.

3.8 Other options considered

As discussed already, AVP gave due consideration to other options in the PSCR, and in PADR analysis, but following the screening phase, not all options were assessed in the cost benefit assessment. For reasons outlined below, the following options were considered unlikely to form part of the preferred option, and therefore did not pass the screening phase in this PADR:

- **66 kV capacitors to address Pillar 1 needs** – AVP assessed the feasibility of both 220 kV and 66 kV capacitors at each of the critical sites for Pillar 1, and found that capacitors on the 66 kV side of a transformer would not always be suitable to address Pillar 1 needs at Deer Park, Tyabb, and the Rowville area on the 220 kV level, and this suitability would depend on the tap position of the transformer between the 66 kV capacitor and the 220 kV voltage being managed. For this reason, AVP did not further consider 66 kV capacitors at these specific sites as technically feasible for this PADR.
- **Option portfolios with two or more dynamic reactive power devices** – combined Pillar Option 2 explored the potential benefits of network dynamic reactive plant (such as SVCs) of addressing both Pillar 1 and Pillar 2 using a single piece of equipment, thereby – in principle – resulting in less overall MVAr investment compared with an option consisting only of reactors and capacitors. However, based on the significant difference in price between options consisting of reactors and capacitors and options including dynamic devices (as indicated by the cost difference between Option 1 and Option 4 of this PADR), AVP found that the increased cost of an SVC compared with the equivalent reactor and capacitor combination outweighs this benefit. Option portfolios with two or more dynamic reactive power devices were therefore not considered economically feasible. Another benefit, if the dynamic plant were to be a synchronous condenser, would be an increase to transient export limits from Victoria to New South Wales. However, there is not currently a need to increase the export limit.
- **Bring forward of Keilor 500/220 kV transformer replacement** – bringing forward the replacement projects of Keilor 500/220 kV transformers to increase their continuous and short-term voltage capability was considered a credible option in the PSCR, on the basis that AVP would engage with AusNet regarding its plans for replacing the existing Keilor 750 MVA 500/220 kV transformers, and the potential and associated costs to bring these replacement projects forward. Given the committed separate project to increase the Keilor 500 kV short-term high voltage limit (see Section 2.2.8), a bring-forward of these transformer replacements no longer helps addressed the identified voltage management needs in this RIT-T.

- **Paper uprate of the DPTS 220 kV lower voltage limit –** while upgrading the Deer Park 220 kV lower voltage limit would defer the need for further investment to support voltages at Deer Park, it is currently limited due to voltage instability for a credible loss of a Deer Park 220/66 kV transformer. AVP will continue engaging with CitiPower/Powercor regarding how future plans may impact this voltage stability limitation, and will provide any further update in the PACR.
- **Paper uprate of other 220 kV sites** – AVP is not exploring a paper uprate of the low voltage limit for other Pillar 1 critical sites because these other critical sites represent a voltage management need for the broader eastern metropolitan Melbourne network, and therefore upgrading the low voltage limit at these specific sites will not defer the need for additional investment.

- **Other combinations of capacity, voltage, location, and connection arrangement** – performing detailed network and economic studies against all possible combinations would be impractical and unnecessary. As described in Sections 3.1, 3.2, and 3.3, AVP has assessed the relative merits of these technical parameter combinations when identifying the credible options included in Section 3.5.

4 Submissions to the PSCR

4.1 Stakeholder submissions to the PSCR

The Metropolitan Melbourne Voltage Management PSCR was published in October 2023. It presented the technical requirements of network and non-network solutions, and invited interested parties to make written submissions.

AVP received two submissions (both being confidential) in response to the PSCR, proposing non-network options involving the development of BESSs at locations around Melbourne.

AVP subsequently engaged directly with the submitters to obtain the information necessary to assess these non-network solutions, and has included the non-network options in this PADR (based on generic information where necessary) to ensure a robust assessment of all potential solutions to the identified need.

5 Description of methodology and scenario assumptions

The modelling carried out in this PADR is based on detailed power flow studies used to estimate the identified need and the impact that credible options have on it. Economic assessments have been used to rank credible options and identify the preferred option that delivers the highest net market benefits. Where possible, all inputs and assumptions have been based on AEMO's most recently published planning datasets, including the latest IASR.

5.1 Overview

The assessments in this PADR are based on the RIT-T application guidelines published in October 2023 by the AER[26].

This chapter describes the key assumptions and methodologies applied in the power flow studies and economic assessment for this PADR. Key assumptions that have informed the identified need and credible options have already been discussed in Section 2.2.

5.2 Assumptions

5.2.1 Analysis period and asset life

The PADR analysis has been undertaken over a 10-year period from 2024-25 to 2033-34.

To capture the 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 has been extrapolated across the life of the asset under that credible option.

Asset life of credible options was assumed to be:

[26] 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.

- 20 years for capacitors.
- 30 years for reactors.
- 30 years for dynamic plant such as an SVC.
- For generator and 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).

5.2.2 Discount rate

The RIT-T requires a base discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.

A base discount rate of 7% (real, pre-tax) has been used in the NPV analysis. This discount rate is sourced from the 2023 *Inputs, Assumptions and Scenarios Report* (IASR)[27] and Appendix 6 of the 2024 ISP[28].

Sensitivity testing has been conducted on the base discount rate, with a lower bound discount rate of 3.0% and an upper bound discount rate of 10.5%, as included in both the 2023 IASR and Appendix 6 of the 2024 ISP.

5.2.3 Reasonable scenarios

The RIT-T requires a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand if each credible option were implemented, compared to the situation where no option is implemented.

A reasonable scenario represents a set of variables or parameters that are not expected to change across each of the credible options or the base case.

Except for specific circumstances, RIT-T proponents must adopt the inputs, assumptions and scenarios from AEMO's most recent IASR.

This RIT-T analysis included three reasonable scenarios from the 2023 IASR, these being the ***Step Change*** scenario, the ***Progressive Change*** scenario, and the ***Green Energy Exports*** scenario. See Section 2.2 of the 2023 IASR for a description of these scenarios and their narratives[29], and Table 2 of the 2023 IASR for the federal and state public policies included in all three scenarios, which include but are not limited to:

- **Emissions reduction targets** for Victoria of 28-33% below 2005 levels by 2025, 50% by 2030, 75-80% by 2035 and net zero by 2050.
- **Victorian Renewable Energy Target (VRET)** of 40% by 2025, 50% by 2030, and intentions to update the VRET with 65% by 2030 and 95% by 2035.
- **Storage targets** for Victoria of 2.6 gigawatts (GW) by 2030 and 6.3 GW by 2035.

[27] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en.

[28] At https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a6-cost-benefit-analysis.pdf?la=en.

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

5.2.4 Weightings applied to each scenario

The cost benefit analysis in this RIT-T has applied the following weightings to each scenario as determined from the 2024 ISP Delphi Panel[30]:

- *Step Change*: 43%.
- *Progressive Change*: 42%.
- *Green Energy Exports*: 15%.

5.2.5 Demand and distributed PV

The RIT-T PADR analysis applied the regional demand and distributed PV forecasts from the 2023 ESOO.

Half-hourly demand traces for each scenario were based on the Draft 2024 ISP. These included the 90% POE, 50% POE, and 10% POE demand conditions with weightings consistent with the *ESOO and Reliability Forecast Methodology Document*[31] as indicated in Table 15.

Table 15 POE weightings

POE	Weighting
10%	30.4%
50%	39.2%
90%	30.4%

Pillar 1 analysis also applied the non-coincident maximum demand forecasts for individual connection points from the AEMO connection point forecasts to traces of these connection points' historical demand to develop future year demand traces for the Pillar 1 modelling. See Section 5.3.3 for a more detailed description.

5.2.6 Generator assumptions

The PADR benefits assessment assumptions (beyond those used in quantifying the identified need as discussed in Section 2.2) included:

  – Draft 2024 ISP scenario-specific development opportunities (that is, new generic generation and storage investment).

- Renewable generator half-hourly output traces from the Draft 2024 ISP.
- Generator fuel costs, emissions intensity, and variable and fixed operating and maintenance costs (OPEX) from the 2023 IASR.

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[30] At https://aemo.com.au/-/media/files/major-publications/isp/2023/2024-isp-delphi-panel---overview.pdf.

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

- Reduced requirements for Victorian system strength minimum generator combinations[32] (for Pillar 2), on the basis that 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.
- Where not available in 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.

5.2.7 Transmission development

Consistent with the PSCR, AVP considered all committed, anticipated, and actionable ISP projects impacting the Victorian region from AEMO's 2023 NEM Transmission Augmentation Information page[33] and in line with the Draft 2024 ISP.

Additionally, AVP assumed a reconfiguration of the Latrobe Valley network following retirement of Yallourn Power Station in 2028, consistent with a draft proposal from the 2023 VAPR and the 2024 ISP.

AVP is also in early stages of preparing two RIT-Ts to address forecast limitations in the western corridors and eastern corridors between metropolitan Melbourne and key Victorian supply hubs, and has considered possible solutions to address these limitations in sensitivity studies, to investigate the robustness of credible options and the proposed preferred option of this RIT-T. See Section 6.5 for outcomes of this sensitivity.

5.2.8 Interconnector transfers in maximum and minimum demand conditions

For maximum demand power flow studies, the following interconnector transfers have been assumed for existing and committed interconnector corridors during high demand periods:

- Low imports (approximately 250 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 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 Stage 1 and 2032-33 for Stage 2, once fully in service).

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[32] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

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

For minimum demand power flow studies and the benefits assessment, the following interconnector transfers have been assumed for existing and committed interconnector corridors during low demand periods[34]:

- Close to zero flow across Victoria to South Australia via Heywood and Murraylink.
- 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.

5.3 Modelling methodologies

AVP used a combination of power system studies and analysis of the Draft 2024 ISP market development modelling to estimate the market benefits associated with each credible option.

5.3.1 Power system studies

Power system studies were undertaken with a PSS®E[35] model to determine the voltage exceedances under a range of scenarios for a ‘do nothing’ future, 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).

Identified Need Pillar 1

For Identified Need Pillar 1, steady-state and Reactive Voltage (QV) stability power system studies focusing on high demand periods were undertaken 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[36] 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.

[34] Noting that power flow studies were only conducted out to 2028-29, and needs in 2033-34 have conservatively been assumed as similar to those in 2028-29, as discussed in Section 2.1.

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

[36] Sensitivities have been conducted to test Identified Need Pillar 1 in a world where some thermal limitations in east and west metropolitan Melbourne are upgraded. More on these sensitivities is included in Section 6.5.

One such example is Deer Park 220 kV, which has thermal limitations on the local Deer Park – Keilor and Deer Park – Geelong 220 kV lines that may 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 MW and 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. Sensitivity analysis was also conducted to test impact of changing in BESS charging behaviours.

5.3.2 Benefits assessment methodology

As this RIT-T is not assessing an actionable ISP project, detailed market modelling has not been necessary to assess the gross benefits of the credible options compared against a 'do nothing' base case. Instead, the market development modelling and time-sequential modelling outcomes from the Draft 2024 ISP have been used as the starting point for assessment of the gross market benefits under each scenario, with and without the credible option. The following section outlines how changes in costs for each relevant market benefit class have been assessed.

5.3.3 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 operator may need to intervene, or automatic schemes may need to be activated, to shed load to maintain voltage stability and to maintain 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 a maximum supportable demand, an estimate of the half-hour demand level was created based on historical patterns and AEMO CPF non-coincident maximum demand forecast for the relevant year.
- Step 2 – if the connection point's demand is above the respective maximum supportable demand, shed 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 runback. Where this generation has some level of emissions intensity, this load shedding would also then result in overall reduced emissions compared with a world where the load is not shed.

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)[37] 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 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 operator 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.

[37] 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.

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 Section 5.2.6. For a non-zero reactive power shortfall, determine the number of additional generators required to be online to remove the reactive power shortfall, and subsequently the generation online that would be displaced (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 the 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 hours.
- 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:

> *(Generator start-up costs + minimum generation* x *generator dispatch cost) – (minimum generation* x *displaced generator cost)*.

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 (MWh)* x *representative generator emissions intensity (kg/MWh)*

> *Cost of emissions ($) = (total emissions of directed generation (kg)* x *VER*[38] *($/kg)) – (total emissions of displaced generation (kg)* x *VER ($/kg))*

[38] 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.

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).

5.3.4 Emissions reduction objective and subsequent rule changes

In May 2023, Energy Ministers amended the National Electricity Objective (NEO) to incorporate an emissions reduction objective[39]. 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. Further information on this market benefit class and how it has been applied in this PADR is discussed in Section 6.1 and Section 6.2.

5.4 Cost estimate methodology

Consistent with information provided in Section 3.6, costs were developed to a class 5A (+/- 30%) estimate using AEMO's latest TCD. Site assessments have been used to first identify credible solution sites that are both technically effective at meeting the Identified Need and have sufficient (brownfield) land capable of accommodating new network options. These site assessments were then used to appropriately inform TCD known and unknown risk allowances unique to each credible solution site that equipment has been costed for, and to identify individual site constraints and complexities that would require new station arrangements or equipment needed for delivering solutions other than the standard reactive equipment and connection assets. Costs are presented in this PADR in real 2023 dollars.

For more information on the selection of credible solution sites, see Section 3.2.

The cost of each option includes the following components:

- Project management.
- Engineering support.
- Equipment and services procurement.
- Installation.

[39] 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.

- Commissioning and testing.
- Project management risk allowance.

Cost estimates are based on the practical capacities of reactive power plant and standard connection arrangements (single-switching) described in Section 3.3.2.

Refer to Section 3.6 for more information on costs and option lead times.

5.5 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. Lead times allowing, this was then set as the individual components' preferred timing. See Chapter 5 where this method is used in identifying preferred timings and staging for the various credible options.

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 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 particular PADR.

6 Detailed cost benefit assessment

6.1 Classes of market benefits not expected to be material

Chapter 4 of the PSCR identified classes of market benefits that were not expected to be material. A class of market benefit is considered immaterial 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.

Classes of market benefits AVP identified as immaterial in the PSCR but has reviewed and identified as material in this PADR include:

- 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.

These and all other classes of market benefits identified as material are discussed in the next section.

AVP has identified that the following classes of market benefits are not expected to be material to this RIT-T:

- **Some wholesale electricity market benefits** – the credible options considered in this PADR 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 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. No additional option value has therefore been explicitly determined for this PADR, although it may be introduced through further analysis of the potential interactions with other RIT-Ts prior to the PACR, as discussed in "differences in the timing of expenditure" above.

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

The classes of market benefits/costs that are material in the case of this RIT-T are:

- Changes in voluntary/involuntary load curtailment.
- Changes in emissions arising from above 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.

6.2.1 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 necessary amount of unserved energy (USE) (see Figure 10 in Section 6.4 for a comparison of USE between the 'do nothing' base case and the proposed preferred option, showing the reduction in USE from this proposed preferred option). The market benefit value was then quantified using the calculated USE and the Value of Customer Reliability (VCR)[40].

6.2.2 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.

6.2.3 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.

[40] 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.

6.2.4 Emissions reduction

Since publication of the PSCR, following an amendment to the NEO to incorporate an emissions reduction objective[41] and subsequent NER rule changes (see more in Section 5.3.4), 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 USE.

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[37].

6.3 Net market benefit assessment

All years presented in remaining sections of this report (in tables, figures, and associated commentary) represent the respective financial-year ending. Costs and benefits are reported in real June 2023 dollars.

6.3.1 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.

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 shed 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 USE for the 'do nothing' base case over the 10-year modelling period are illustrated in Table 16 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 6, Figure 7 and Figure 8 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 case. The load areas shown in these figures were determined as those that are most effective to shed load and to relieve under-voltage exceedances included in Section 2.1.

[41] 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.

In these figures, where the connection point forecast exceeds the maximum supportable demand is where USE 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 USE 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 6, the maximum supportable demand decreases due to increased loading in the western metropolitan area, in particular at Geelong. The load at Geelong impacts the maximum supportable demand at Deer Park but load shedding 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 7, 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 metro 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 A and 50 MVAr 66 kV capacitor at Templestowe, as shown in Figure 8. After Yallourn retires in 2029, 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 metro increases, the loading of the Rowville A1 transformer increases and therefore max 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 B.

Table 16 '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 17.

Table 17 '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 6 'Do nothing' maximum supportable demand at the critical site Deer Park 220 kV

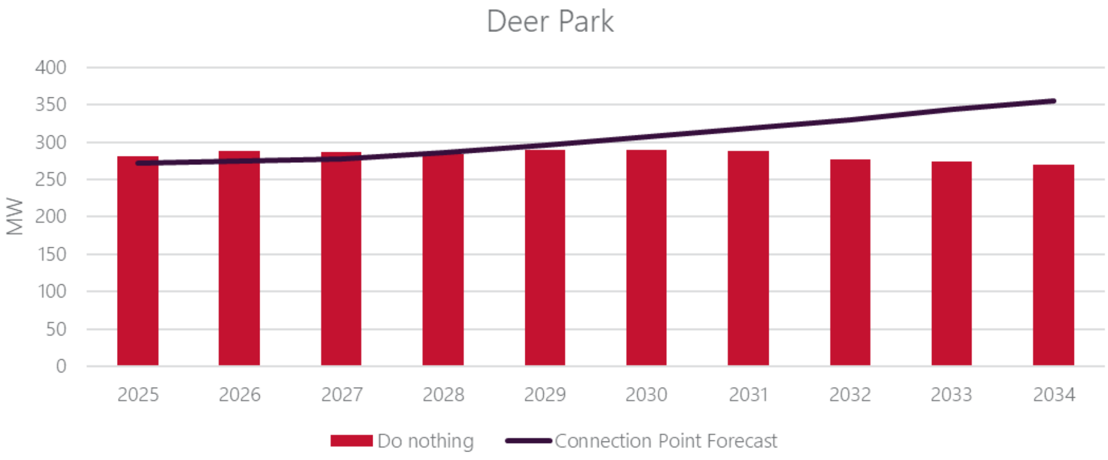
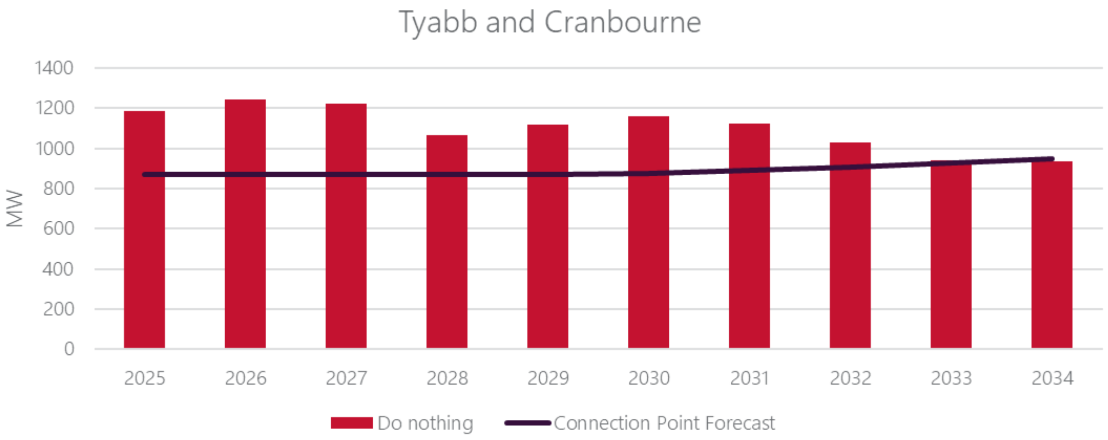
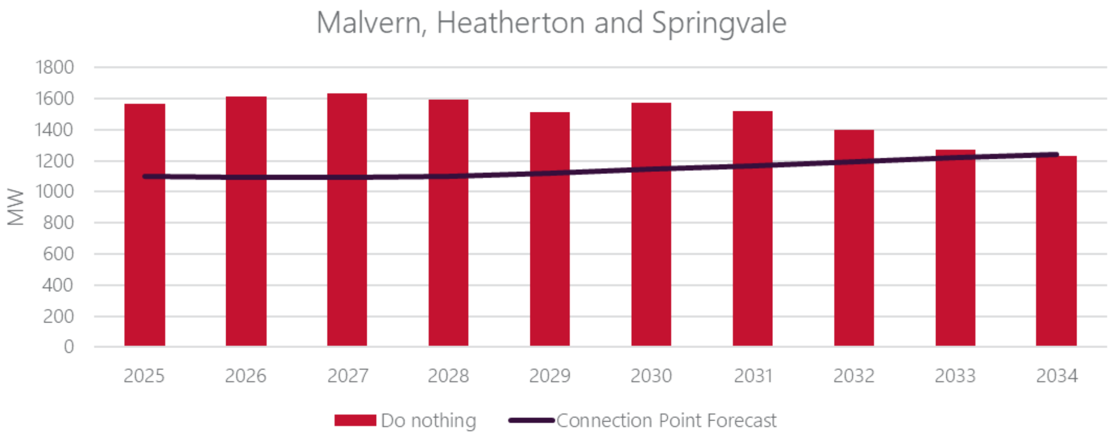


Figure 7 'Do nothing' maximum supportable demand at the critical site Tyabb 220 kV[A]



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 8 '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.

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 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)[42] has been calculated using generator fuel costs (including fuel used in start-up) and operating and maintenance costs, as discussed in Section 5.3.3.

These are shown for the 'do nothing' base case for the 10-year modelling period in Table 18. The total cost associated with this intervention is a sum of the out of merit order dispatch costs and start-up costs of these generators directed online, and a deduction of the dispatch costs of generation that is subsequently displaced in the market. This displaced generation is variable renewable energy (VRE) where dispatched online and available for curtailment, or otherwise coal-fired synchronous generation where dispatched online.

Table 18 '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 0**Error! Reference source not found.**.

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 20.

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

Table 19 '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 20 '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**

6.3.2 Optimal size, timing and staging for each credible option

Optimal size

As described in Section 2.1, the critical sites which require voltage management support during high demand periods are Deer Park 220 kV, Tyabb 220 kV, and the Rowville 220 kV area. Therefore, any credible solution to address Pillar 1 of the identified need effectively needs to address any reactive shortfall at these sites, and should be sized accordingly taking into account the effectiveness of the solution site(s) (see Table 12 in Section 3.1 for a shortlist of candidate solution sites).

The optimal size of investment correlates with the amount of reactive shortfall to be addressed at these sites. As discussed in Section 2.1, the largest generating reactive requirement at each site over the forecast is 95 MVAr, 55 MVAr, and 30 MVAr for Deer Park, Rowville, and Tyabb respectively[43]. Reactive solutions placed at Tyabb 220 kV and/or in the Rowville 220 kV area are summarised in option assessments below as East Metro.

The critical site that requires voltage management support during low demand periods is South Morang 500 kV. Engineering studies have indicated that providing voltage support for this site results in sufficient voltage support for all sites in metropolitan Melbourne at risk of over-voltage exceedances in the next 10 years. Therefore, any

[43] Based on power system studies assuming 10% POE maximum Victorian operational demand for the 2023 ESOO *Central* scenario

credible solution to address Pillar 2 of the identified need effectively needs to address any reactive shortfall at South Morang 500 kV, and should be sized accordingly taking into account the effectiveness of the solution site(s) to meet this shortfall (see Table 13 in Section 3.1 for a shortlist of candidate solution sites). In the option assessments below, solutions have been placed on the 220 kV network, as 220 kV-connected solutions have proven more economically viable for this RIT-T than 330 kV- or 500 kV-connected solutions, due to comparatively higher connection costs on the 330 kV and 500 kV level. The 220 kV solution sites tested in the option assessments below are in line with sites that have good technical effectiveness at meeting the identified need and have sufficient (brownfield) land capable of accommodating new network options (as discussed in Section 3.2).

The optimal size of investment correlates with the amount of reactive shortfall to be addressed at South Morang 500 kV. As discussed in Section 2.1, the largest absorbing reactive requirement at South Morang 500 kV for the next 10 years is 215 MVAr.

Optimal timing and staging

As discussed in Section 2.1, the largest generating reactive requirement at the critical sites changes annually over the modelling period. The largest absorbing reactive requirement at South Morang 500 kV also changes annually over the modelling period. It is therefore likely to be beneficial to stage the solution in a progressive build-out to address the increasing reactive support requirements over the ten-year period.

To determine the optimal timing and staging for each credible options, analysis focused on the optimal timing and number of capacitors and reactors to the identified need, and then considered the value of substituting some capacitors and/or reactors with technology solutions that can help manage both under- and over-voltages.

Optimal size and timing for credible Option 1

Credible Option 1 comprises a portfolio of 220kV capacitors and reactors, with the standard size per unit assumed to be 100 MVAr (see Section 3.3.2).

Table 21 and Table 22 below show the different capacitor sizes considered for Option 1, and the gross and net benefits they would provide each year over the next 10 years to address Pillar 1 of the identified need, through reducing the ‘do nothing’ involuntary load curtailment costs shown in Table 16 and increasing the ‘do nothing’ emissions costs shown in Table 17.

In Table 22, the optimal investment size is indicated by the investment size that yields the highest positive net market benefits across the 10 years (see values shaded purple). The optimal timing for each component of the investment (up to the optimal investment size) is determined by the first occurrence of positive net market benefits (see values in blue text). This indicates the optimal investment size and timing for capacitors in Option 1 is:

- 1 x 100 MVAr capacitor for Deer Park 220 kV in 2031; and
- 2 x 100 MVAr capacitors for East Metro[44] in 2034,

where Deer Park investment marginally supports East Metro and vice versa.

[44] Throughout this section, east metro represents the two optimal investment sites (Tyabb 220 kV and Malvern 220 kV) to address voltage management needs in eastern metropolitan Melbourne for Pillar 1. The investment size for East metro represents total MVAr combined across these two investment sites.

It is not until 2034 that the additional East Metro capacitors provide a higher net market benefit than the Deer Park capacitor alone, and the Deer Park capacitor provides enough support to eastern metropolitan Melbourne in 2033 such that the remaining need does not justify the additional East Metro capacitors in this year. The net market benefit of the second capacitor at East Metro is also marginal, with annual net market benefits for the option with only one capacitor being within $100,000 of the net benefits yielded by the option with two East Metro capacitors in 2034.

Table 21 Option 1 gross benefits delivered in addressing Pillar 1 of the identified need ($M)

Investment size	Weighted – gross benefits $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS 1 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.0	20.9
DPTS 2 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.3	21.7
DPTS 3 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.5	22.1
East Metro 1 x 100 MVAr	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	2.1	3.8
East Metro 2 x 100 MVAr	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	2.5	6.1
East Metro 3 x 100 MVAr	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	3.6	7.5
East Metro 4 x 100 MVAr	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	3.6	7.5
DPTS 1 x 100 MVAr & East Metro 1 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.6	22.5
DPTS 2 x 100 MVAr & East Metro 1 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.6	22.6
DPTS 1 x 100 MVAr & East Metro 2 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 2 x 100 MVAr & East Metro 2 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 1 x 100 MVAr & East Metro 3 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 2 x 100 MVAr & East Metro 3 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2

Table 22 Option 1 net benefits delivered in addressing Pillar 1 of the identified need ($M)

Investment size	Capital cost ($M)	Annualised cost ($M) [A]	Weighted – net benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS 1 x 100 MVAr	6.9	0.6	-0.6	-0.6	-0.6	-0.6	-0.5	-0.3	0.2	1.4	9.4	20.3
DPTS 2 x 100 MVAr	13.3	1.2	-1.2	-1.2	-1.2	-1.1	-1.1	-0.8	-0.4	0.8	9.2	20.5
DPTS 3 x 100 MVAr	19.7	1.8	-1.8	-1.8	-1.7	-1.7	-1.6	-1.4	-0.9	0.3	8.8	20.3
East Metro 100 MVAr	6.4	0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.5	-0.4	1.6	3.3
East Metro 2 x 100 MVAr	12.8	1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.0	1.3	5.0
East Metro 3 x 100 MVAr	19.2	1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.5	1.8	5.8
East Metro 4 x 100 MVAr	25.6	2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.2	-2.1	1.3	5.2
DPTS 1 x 100 MVAr & East Metro 1 x 100 MVAr	13.3	1.2	-1.2	-1.2	-1.2	-1.1	-1.1	-0.8	-0.4	0.8	9.4	21.3

Investment size	Capital cost ($M)	Annualised cost ($M) [A]	Weighted – net benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS 2 x 100 MVAr & East Metro 1 x 100 MVAr	19.7	1.8	-1.8	-1.8	-1.7	-1.7	-1.6	-1.4	-0.9	0.3	8.9	20.9
DPTS 1 x 100 MVAr & East Metro 2 x 100 MVAr	19.7	1.8	-1.8	-1.8	-1.7	-1.7	-1.6	-1.4	-0.9	0.3	9.1	21.4
DPTS 2 x 100 MVAr & East Metro 2 x 100 MVAr	26.1	2.3	-2.3	-2.3	-2.3	-2.3	-2.2	-2.0	-1.5	-0.3	8.5	20.9
DPTS 1 x 100 MVAr & East Metro 3 x 100 MVAr	26.1	2.3	-2.3	-2.3	-2.3	-2.3	-2.2	-2.0	-1.5	-0.3	8.5	20.8
DPTS 2 x 100 MVAr & East Metro 3 x 100 MVAr	32.5	2.9	-2.9	-2.9	-2.9	-2.8	-2.8	-2.5	-2.1	-0.9	7.9	20.3

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

Table 23 and Table 24 display the different reactor sizes considered for Option 1, and the gross and net benefits they would provide each year annually over the next 10 years to address Pillar 2 of the identified need, through reducing the 'do nothing' costs shown in Table 18 and 0.

In Table 24, the optimal investment size is determined by the highest positive net benefit across the 10 years (see values shaded purple). The optimal timing for each component of the investment (up to the optimal investment size) is determined by the first occurrence of positive net benefit (see values in blue text). This indicates the optimal investment size and timing for reactors in Option 1 is 3 x 100 MVAr reactors on the 220 kV level in 2029 (without any staging).

This correlates with the average effectiveness of possible solution sites on the 220 kV level such as South Morang, Thomastown, West Melbourne, Altona, Brooklyn, and Keilor, as included in Table 13 (in Section 3.1), in meeting the largest absorbing reactive requirement of 215 MVAr as included in Table 6 (in Section 2.1).

Table 23 Option 1 gross benefits delivered in addressing Pillar 2 of the identified need ($M)

Investment size	Weighted – gross benefits $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 x 100 MVAr	0.0	0.0	0.1	0.5	1.7	3.3	4.7	4.6	4.7	4.5
2 x 100 MVAr	0.0	0.0	0.1	0.8	2.6	5.0	7.8	7.9	9.9	11.0
3 x 100 MVAr	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1
4 x 100 MVAr	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1

Table 24 Option 1 net market benefits delivered in addressing Pillar 2 of the identified need ($M)

Investment size	Capital cost ($M)	Annualised cost ($M)[A]	Weighted – net benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 x 100 MVAr	8.6	0.7	-0.7	-0.7	-0.5	-0.1	1.1	2.6	4.0	4.0	4.1	3.8
2 x 100 MVAr	17.2	1.3	-1.3	-1.3	-1.2	-0.5	1.3	3.7	6.5	6.6	8.6	9.7
3 x 100 MVAr	25.9	2.0	-2.0	-2.0	-1.8	-0.5	2.6	6.9	12.3	12.4	16.9	19.1
4 x 100 MVAr	34.5	2.6	-2.6	-2.6	-2.5	-1.1	2.0	6.3	11.6	11.7	16.2	18.5

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

Credible Option 1

Based on the above analysis, the optimal investment size and timing for credible Option 1 is:

- 3 x 100 MVAr reactors[45] on the 220 kV level in 2029 (to address Pillar 2).
- 1 x 100 MVAr capacitor for Deer Park 220 kV in 2031 (to address Pillar 1).
- 2 x 100 MVAr capacitors for East Metro in 2034 (to address Pillar 1).

Table 25 shows the annual net market benefits of Option 1 across the next 10 years considering the staged delivery of reactors and capacitors in line with the optimal sizes and timings above. See ▯ (in Section 6.3.3 below) for a net present value summary of the benefits of this credible option, which considers the annual net market benefits of each investment asset across its life.

Table 25 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)	25.9	2.0					3 x 100 MVAr reactors						
2 (2031)	32.8	2.6							1 x 100 MVAr capacitor at Deer Park				
3 (2034)	45.6	3.7										2 x 100 MVAr in East Metro	
Total	45.6	3.7					2.6	6.9	12.5	13.8	26.3	40.5	37.6

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

Optimal size and timing for credible Option 2

Credible Option 2 comprises a portfolio of 220 kV capacitors and reactors, with the standard size per unit assumed to be 100 MVAr, and a non-network BESS service located in eastern metropolitan Melbourne.

Assuming that the non-network service forms part of the solution, Table 26 below shows the different capacitor sizes considered for Option 2, and the gross market benefits they would provide each year over the next 10 years

[45] At a combination of South Morang, Thomastown, and West Melbourne.

to meet the Pillar 1 identified need, through reducing the 'do nothing' costs shown in Table 16 and Table 17. Due to the confidential nature of this option, net market benefits for Option 2 have been omitted from this report.

Table 26 Option 2 gross benefits delivered in addressing Pillar 1 of the identified need ($M)

Investment size	Capital cost A ($M)	Annualised cost ($M) B	Weighted – gross benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
East Metro non-network service	0.0	Confidential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	3.1
East Metro 1 x 100 MVAR + non-network service	6.4	Confidential	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	2.4	5.8
East Metro 2 x 100 MVAR + non-network service	12.8	Confidential	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	2.5	6.2
East Metro 3 x 100 MVAR + non-network service	19.2	Confidential	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	3.6	7.5
DPTS 1 x 100 MVAr & East Metro non-network service	6.9	Confidential	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.5	22.0
DPTS 1 x 100 MVAr & East Metro 1 x 100 MVAR + non-network service	13.3	Confidential	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.7	22.8
DPTS 2 x 100 MVAr & East Metro 1 x 100 MVAR + non-network service	19.7	Confidential	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.0
DPTS 100 MVAr & East Metro 2 x 100 MVAR + non-network service	19.7	Confidential	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 2 x 100 MVAr & East Metro 2 x 100 MVAR + non-network service	26.1	Confidential	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 1 x 100 MVAr & East Metro 3 x 100 MVAR + non-network service	26.1	Confidential	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2

A. Capital cost of the network components only.
B. Annualised cost represents the annualised capital cost plus operational and maintenance costs.

The option that maximises gross market benefits for this credible option has two capacitors at East Metro. While not able to be shown, the option that maximises net market benefits has one capacitor at East Metro once investment costs have been factored into account. Therefore, the optimal investment size for Option 2 to manage Pillar 1 is:

- 1 x 100 MVAr capacitor for Deer Park 220 kV in 2031 (based on optimal timing in Table 22).

- 1 x 100 MVAr capacitor for East Metro in 2034 (based on optimal timing in Table 22, where 2034 is the first year that additional East Metro capacitors provide a higher net market benefit than the Deer Park capacitor alone).
- Non-network BESS service in eastern metropolitan Melbourne in 2034.

The non-network service defers the need for one of the capacitors at East Metro, reducing the total capital cost by $6.4 million. Compared to the Table 21 solution with only a single capacitor at East Metro, the inclusion of the non-network service in 2034 provides an additional $300,000 in annual gross market benefits in that year. There is insufficient incremental net market benefit to justify an additional capacitor, even once the annual cost of the non-network option is taken into account.

Assuming that the non-network service forms part of the solution, Table 27 below shows the different reactor sizes considered for Option 2, and the gross benefits they would provide each year over the next 10 years to meet the Pillar 2 identified need, through reducing the 'do nothing' costs shown in Table 18 and 0.

Due to the confidential nature of the costs associated with this option, net market benefits for Option 2 have been omitted from this report.

Table 27 Option 2 gross benefits delivered in addressing Pillar 2 of the identified need ($M)

Investment size	Capital cost ($M)[A]	Annualised cost ($M)[B]	Weighted – gross benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
East Metro non-network service	0.0	Confidential	0.0	0.0	0.1	0.1	0.2	0.4	0.5	0.6	0.4	0.3
1 x 100 MVAr + East Metro non-network service	8.6	Confidential	0.0	0.0	0.1	0.8	2.3	4.4	7.1	7.2	9.4	10.5
2 x 100 MVAr + East Metro non-network service	17.2	Confidential	0.0	0.0	0.1	0.9	3.1	5.7	8.7	8.9	10.7	11.7
3 x 100 MVAr + East Metro non-network service	25.9	Confidential	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1
4 x 100 MVAr + East Metro non-network service	34.5	Confidential	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1

A. Capital cost of the network components only.
B. Annualised cost represents the annualised capital cost plus operating and maintenance costs.

In this instance, the investment size that yields maximum gross market benefits in meeting the Pillar 2 identified need also yields the maximum net market benefits; that is, 3 x 100 MVAr reactors on the 220 kV level and the non-network service in eastern metropolitan Melbourne in 2029.

Comparing Table 27 with Table 23 for Option 1, this shows that the non-network service forming part of Credible Option 2 does not defer the need for one of the three reactors included in Credible Option 1, nor does it provide additional gross benefits beyond those accrued with the three reactors, which indicates that there is no benefit in bringing forward the non-network service from 2034 when it displaces the need for one of the East Metro capacitors.

Credible Option 2

Based on the above analysis, the optimal investment size and timing for credible Option 2 is:

- 3 x 100 MVAr reactors on the 220 kV level in 2029 (to address Pillar 2).
- 1 x 100 MVAr capacitor for Deer Park 220 kV in 2031 (to address Pillar 1).
- 1 x 100 MVAr capacitor for East Metro in 2034 (to address Pillar 1).
- Non-network BESS service in eastern metropolitan Melbourne in 2034 (to address Pillars 1 and 2).

Given the confidential nature of the non-network BESS service, a table equivalent with Table 25 is not possible for Option 2.

Optimal size and timing for Option 3

Option 3 comprises a portfolio of 220 kV capacitors and reactors, with the standard size per unit assumed to be 100 MVAr, and a non-network BESS option at Deer Park 220 kV.

Assuming that the non-network option forms part of the solution, 0 below shows the different capacitor sizes considered for Option 3, and the gross benefits they would provide each year over the next 10 years to address Pillar 1 of the identified need, through reducing the ‘do nothing’ involuntary load curtailment costs shown in Table 16 and increasing the ‘do nothing’ emissions costs shown in Table 17.

The optimal investment size is determined by the highest positive net market benefits across the 10 years, and the optimal timing for each component of the investment (up to the optimal investment size) is determined by the first occurrence of positive net benefits (see values in blue text).

Table 29 shows that this option does not yield positive annual net benefits for the next 10 years, however the investment size that minimises negative annual net benefits is:

- Non-network BESS option at Deer Park 220 kV in 2031 (assuming delivery no sooner than the optimal timing of investment at Deer Park for Option 1).
- 1x 100 MVAr capacitor in East Metro in 2034 (same as optimal timing of investment in East Metro for Option 1)

The inclusion of the non-network option at Deer Park displaces the need for a capacitor in the east metro region, delivering up to $600,000 more in annual net benefits across 2031 to 2034 compared to the investment size that also has a second capacitor installed.

Table 28 Option 3 gross benefits delivered in addressing Pillar 1 of the identified need ($M)

Investment size	Weighted – gross benefits $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS non-network BESS option	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.2	21.4
DPTS 100 MVAr + DPTS non-network BESS option	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.4	21.9
DPTS non-network BESS option + East Metro 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.7	23.0
DPTS 100 MVAr + DPTS non-network BESS option + East Metro 1 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.7	23.0
DPTS non-network BESS option + East Metro 2x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 100 MVAr + DPTS non-network BESS option + East Metro 2 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS non-network BESS option + East Metro 3 x 100 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2

Table 29 Option 3 net benefits delivered in addressing Pillar 1 of the identified need ($M)

Investment size	Capital cost ($M)	Annualised cost ($M)[A]	Weighted – net benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS non-network BESS option	268.8	26.1	-26.1	-26.1	-26.1	-26.1	-26.0	-25.8	-25.3	-24.1	-15.9	-4.8
DPTS 100 MVAr + DPTS non-network BESS option	275.2	26.7	-26.7	-26.7	-26.7	-26.6	-26.6	-26.3	-25.9	-24.7	-16.3	-4.8
DPTS non-network BESS option + East Metro 100 MVAr	275.2	26.7	-26.7	-26.7	-26.7	-26.6	-26.6	-26.3	-25.9	-24.7	-16.0	-3.7
DPTS 100 MVAr + DPTS non-network BESS option + East Metro 1x100 MVAr	281.6	27.3	-27.3	-27.3	-27.3	-27.2	-27.2	-26.9	-26.5	-25.2	-16.5	-4.3
DPTS non-network BESS option + East Metro 2x100 MVAr	281.6	27.3	-27.3	-27.3	-27.3	-27.2	-27.2	-26.9	-26.5	-25.2	-16.5	-4.0
DPTS 100 MVAr + DPTS non-network BESS option + East Metro 2x100 MVAr	288.0	27.8	-27.8	-27.8	-27.8	-27.8	-27.7	-27.5	-27.0	-25.8	-17.0	-4.6
DPTS non-network BESS option + East Metro 3x100 MVAr	288.0	27.8	-27.8	-27.8	-27.8	-27.8	-27.7	-27.5	-27.0	-25.8	-17.0	-4.6

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

Assuming that the non-network service forms part of the solution, Table 30 and Table 31 below show the different reactor sizes considered for Option 3, and the gross and net benefits they would provide each year over the next 10 years to address Pillar 2 of the identified need, through reducing the ‘do nothing’ costs.

Similar to Pillar 1, Table 31 shows that this option does not yield positive annual net benefits for the next 10 years, however the investment size that maximises gross benefits and also minimises negative annual net benefits is 3 x

100 MVAr reactors on the 220 kV level and the non-network BESS option at Deer Park 220 kV in 2029 (same as optimal timing of investment in 220 kV reactors for Option 1).

Comparing Table 30 with Table 23 for Option 1, this shows that a non-network BESS option at Deer Park brought forward from 2031 does not defer the need for one of the three reactors included in Credible Option 1, nor does it provide additional gross benefits beyond those accrued with the three reactors, which indicates that there is no benefit in bringing forward the non-network service from 2031 when it displaces the need for the Deer Park capacitor included in option 1.

Table 30 Option 3 gross benefits delivered in addressing Pillar 2 of the identified need ($M)

Investment size	Weighted – gross benefits $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS non-network BESS option	0.0	0.0	0.1	0.3	1.2	2.1	2.6	2.8	2.3	2.1
1 x 100 MVAr + DPTS non-network BESS option	0.0	0.0	0.1	0.8	2.3	4.4	7.1	7.2	9.4	10.5
2 x 100 MVAr + DPTS non-network BESS option	0.0	0.0	0.1	1.2	3.9	7.5	11.4	11.4	13.6	14.5
3 x 100 MVAr + DPTS non-network BESS option	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1
4 x 100 MVAr + DPTS non-network BESS option	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1

Table 31 Option 3 net benefits delivered in addressing Pillar 2 of the identified need ($M)

Investment size	Capital cost ($M)	Annualised cost ($M)[A]	Weighted – net benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS non-network BESS option	268.8	26.1	-26.1	-26.1	-26.0	-25.8	-24.9	-24.0	-23.5	-23.4	-23.8	-24.0
1 x 100 MVAr + DPTS non-network BESS option	277.4	26.8	-26.8	-26.8	-26.7	-26.0	-24.5	-22.3	-19.7	-19.6	-17.4	-16.2
2 x 100 MVAr + DPTS non-network BESS option	286.0	27.4	-27.4	-27.4	-27.3	-26.2	-23.5	-19.9	-16.0	-16.1	-13.8	-13.0
3 x 100 MVAr + DPTS non-network BESS option	294.7	28.1	-28.1	-28.1	-28.0	-26.6	-23.5	-19.2	-13.9	-13.8	-9.2	-7.0
4 x 100 MVAr + DPTS non-network BESS option	303.3	28.8	-28.8	-28.8	-28.6	-27.3	-24.2	-19.9	-14.5	-14.4	-9.9	-7.7

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

Credible Option 3

Based on the above analysis, the optimal investment size and timing for credible Option 3 is:

- 3 x 100 MVAr reactors on the 220 kV level in 2029 (to address Pillar 2).

- Non-network BESS option at Deer Park 220 kV in 2031 (to address Pillars 1 and 2).
- 1 x 100 MVAr capacitor in East Metro in 2034 (same as optimal timing if only these capacitors were built, to address Pillar 1).

Table 32 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 (noting that some annual net market benefits become positive when the cost of this option is considered across both pillars). See (in Section 6.3.3 below) below for an NPV summary of the benefits of this credible option, which considers the annual net market benefits of each investment asset across its life.

Table 32 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)	25.9	2.0					3 x 100 MVAr reactors						
2 (2031)	294.7	25.7							Deer Park non-network service				
3 (2034)	301.1	26.2										1 x 100 MVAr in East Metro	
Total	301.1	26.2					2.6	6.9	-13.1	-11.7	1.0	15.4	12.4

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

Optimal size and timing for Option 4

Option 4 comprises a portfolio of 220 kV capacitors and reactors, with the standard size per unit assumed to be 100 MVAr, and a single 150 MVAr SVC. As discussed in Section 3.5.1, other SVC sizes and sites were tested, however a 150 MVAr SVC at Malvern 220 kV proved to be most effective at displacing both capacitors and reactors.

Assuming that the SVC forms part of the solution, Table 33 and Table 34 below show the different capacitor sizes considered for Option 4, and the gross and net benefits they would provide each year over the next 10 years to address Pillar 1 of the identified need, through reducing the 'do nothing' involuntary load curtailment costs shown in Table 16 and increasing the 'do nothing' emissions costs shown in Table 17.

In Table 34, the optimal investment size is indicated by the investment size that maximises net market benefits across the 10 years (see values shaded purple). The optimal timing for each component of the investment (up to the optimal investment size) is indicated by when net benefits first become positive for that component (see values in blue text). This indicates the optimal investment size and timing for the Pillar 1 components of Option 4 is:

- 1 x 100 MVAr capacitor at Deer Park 220 kV in 2031 (based on Option 1 timing).
- 1 x 150 MVAr SVC in East Metro in 2034 (where this is the first year that the SVC on its own yields positive net benefits, and the positive net benefits in 2033 of this table are owing to the $9.4 million of net benefits provided by the Deer Park capacitor in this year, in line with Table 22).

The above indicates that the SVC displaces the need for both of the 100 MVAr capacitors in East Metro included as part of Option 1.

Table 33 Option 4 – gross benefits delivered in addressing Pillar 1 of the identified need ($M)

Investment size	Weighted – gross benefits $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
East Metro 150 MVAr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	2.2	5.7
East Metro 1 x 100 MVAr + 150 MVAr SVC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	3.0	7.5
East Metro 2 x 100 MVAr + 150 MVAr SVC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	3.0	7.5
DPTS 1 x 100 MVAr & East Metro 150 MVAr	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.6	22.7
DPTS 2 x 100 MVAr & East Metro 150 MVAr SVC	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.7	22.9
DPTS 100 MVAr & East Metro 1 x 100 MVAr + 150 MVAr SVC	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 200 MVAr & East Metro 1 x 100 MVAr + 150 MVAr SVC	0.0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2
DPTS 100 MVAr & East Metro 2 x 100 MVAr + 150 MVAr SVC	0	0.0	0.0	0.1	0.1	0.4	0.8	2.0	10.8	23.2

Table 34 Option 4 – net benefits delivered in addressing Pillar 1 of the identified need ($M)

Investment size	Capital cost ($M)	Annualised cost ($M) [A]	Weighted – gross benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
East Metro 150 MVAr	33.1	2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.3	-0.3	3.1
East Metro 1 x 100 MVAr + 150 MVAr SVC	39.5	3.1	-3.1	-3.1	-3.1	-3.1	-3.1	-3.1	-3.1	-2.9	-0.1	4.4
East Metro 2 x 100 MVAr + 150 MVAr SVC	45.9	3.7	-3.7	-3.7	-3.7	-3.7	-3.7	-3.7	-3.7	-3.5	-0.6	3.8
DPTS 1 x 100 MVAr & East Metro 150 MVAr	40.0	3.1	-3.1	-3.1	-3.1	-3.1	-3.0	-2.8	-2.3	-1.1	7.5	19.6
DPTS 2 x 100 MVAr & East Metro 150 MVAr SVC	46.4	3.7	-3.7	-3.7	-3.7	-3.6	-3.6	-3.3	-2.9	-1.7	7.0	19.2
DPTS 100 MVAr & East Metro 1 x 100 MVAr + 150 MVAr SVC	46.4	3.7	-3.7	-3.7	-3.7	-3.6	-3.6	-3.3	-2.9	-1.7	7.1	19.5
DPTS 200 MVAr & East Metro 1 x 100 MVAr + 150 MVAr SVC	52.8	4.3	-4.3	-4.3	-4.3	-4.2	-4.2	-3.9	-3.5	-2.2	6.5	19.0

Investment size	Capital cost ($M)	Annualised cost ($M) A	Weighted – gross benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
DPTS 100 MVAr & East Metro 2 x 100 MVAr + 150 MVAr SVC	52.8	4.3	-4.3	-4.3	-4.3	-4.2	-4.2	-3.9	-3.5	-2.2	6.5	19.0

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

Assuming that the SVC forms part of the solution, Table 35 and Table 36 below show the different reactor sizes considered for Option 4, and the gross and net benefits they would provide each year over the next 10 years to address Pillar 1 of the identified need, through reducing Pillar 2 'do nothing' costs shown in Table 18**Error! Reference source not found.** and 0**Error! Reference source not found.**.

In Table 36, the optimal investment size is indicated by the highest positive net benefits across the 10 years (see values shaded purple). Considering Table 24 and Table 36 together, this indicates the optimal investment size and timing for reactors and SVC in Option 4 is:

- 2 x 100 MVAr reactors on the 220 kV level in 2029 (based on optimal timing in Option 1).
- 1 x 150 MVAr SVC at Malvern 220 kV in 2029.

This indicates that the SVC displaces the need for one of the 3 x 100 MVAr reactors included as part of Option 1, resulting in possible benefit in bringing forward the SVC to 2029 from 2034. Table 37 assesses the net benefits of the different investment components across both pillars, to ascertain the optimal size and timing considering both pillars.

Table 35 Option 4 – gross benefits delivered in addressing Pillar 2 of the identified need ($M)

Investment size	Weighted – gross benefits $M									
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
150 MVAr	0.0	0.0	0.1	0.8	2.3	4.4	7.1	7.2	9.4	10.5
1 x 100 MVAr + 150 MVAr	0.0	0.0	0.1	1.0	3.3	6.0	9.1	9.3	11.1	12.1
2 x 100 MVAr + 150 MVAr	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1
3 x 100 MVAr + 150 MVAr	0.0	0.0	0.1	1.5	4.6	8.9	14.2	14.4	18.9	21.1

Table 36 Option 4 – net benefits delivered in addressing Pillar 2 of the identified need ($M)

Investment size	Capital cost ($M)	Annualised cost ($M) A	Weighted – net benefits $M									
			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
150 MVAr	33.1	2.5	-2.5	-2.5	-2.4	-1.8	-0.2	1.9	4.6	4.7	6.9	8.0
1 x 100 MVAr + 150 MVAr	41.7	3.2	-3.2	-3.2	-3.0	-2.2	0.1	2.9	5.9	6.1	7.9	8.9
2 x 100 MVAr + 150 MVAr	50.3	3.8	-3.8	-3.8	-3.7	-2.3	0.8	5.1	10.4	10.5	15.0	17.3
3 x 100 MVAr + 150 MVAr	58.9	4.5	-4.5	-4.5	-4.4	-3.0	0.1	4.4	9.8	9.9	14.4	16.6

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

Table 37 Option 4 – net benefits delivered in addressing both Pillars of the identified need ($M)

Pillar 1 Investment size	Pillar 2 Investment size	Capital cost ($M)	Annualised cost ($M)	Weighted – net benefits $M									
				2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
East Metro 150 MVAr	1 x 100 MVAr	41.7	3.2	-3.2	-3.2	-3.0	-2.2	0.1	2.9	5.9	6.3	10.2	14.6
DPTS 1 x 100 MVAr & East Metro 150 MVAr	1 x 100 MVAr	48.6	3.8	-3.8	-3.8	-3.6	-2.7	-0.4	2.6	6.1	7.5	17.9	31.0
DPTS 1 x 100 MVAr & East Metro 1 x 100 MVAr + 150 MVAr SVC	1 x 100 MVAr	55.0	4.4	-4.4	-4.4	-4.2	-3.3	-0.9	2.0	5.6	7.0	17.5	31.0
East Metro 150 MVAr	2 x 100 MVAr	50.3	3.8	-3.8	-3.8	-3.7	-2.3	0.8	5.1	10.4	10.7	17.3	22.9
DPTS 1 x 100 MVAr & East Metro 150 MVAr	2x 100 MVAr	57.3	4.4	-4.4	-4.4	-4.3	-2.9	0.3	4.8	10.6	11.9	25.0	39.3
DPTS 1 x 100 MVAr & East Metro 1 x 100 MVAr + 150 MVAr SVC	2 x 100 MVAr	63.6	5.0	-5.0	-5.0	-4.9	-3.5	-0.3	4.2	10.0	11.4	24.7	39.3
East Metro 150 MVAr	3 x 100 MVAr	58.9	4.5	-4.5	-4.5	-4.4	-3.0	0.1	4.4	9.8	10.0	16.6	22.3
DPTS 1 x 100 MVAr & East Metro 150 MVAr	3 x 100 MVAr	65.9	5.1	-5.1	-5.1	-5.0	-3.5	-0.4	4.1	10.0	11.3	24.4	38.7
DPTS 1 x 100 MVAr & East Metro 1 x 100 MVAr + 150 MVAr SVC	3 x 100 MVAr	72.3	5.7	-5.7	-5.7	-5.5	-4.1	-1.0	3.6	9.4	10.7	24.0	38.7

Credible Option 4

Table 37 above showed the optimal size and timing for credible Option 4 when considering that the cost of the SVC is shared across both Pillars. This shows that the SVC does defer the need for one of the three reactors included in Option 1 when maximising net benefits, which means there is a benefit in bringing forward the SVC from 2034 when it displaces the need for the East Metro capacitors.

Based on the above analysis, the optimal investment size and timing for credible Option 4 is:

- 2 x 100 MVAr reactors on the 220 kV level in 2029. (to address Pillar 2).
- 1 x 150 MVAr SVC at Malvern 220 kV in 2029. (to address Pillar 1 and 2).
- 1 x 100 MVAr capacitor at Deer Park 220 kV in 2031. (to address Pillar 1).

Table 38 shows the annual net market benefits of Option 4 across the next 10 years considering the staged delivery of reactors, capacitors, and an SVC in line with the optimal sizes and timings above. See below for an

NPV summary of the benefits of this credible option, which considers the annual net market benefits of each investment asset across its life.

Table 38 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)	50.3	3.8					2 x 100 MVAr reactors and 1 x 150 MVAr SVC in East Metro						
2 (2031)	57.3	4.4							1 x 100 MVAr capacitor at Deer Park				
Total	57.3	4.4					0.8	5.1	10.6	11.9	25.0	39.3	36.4

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

6.3.3 Summary of market benefits of credible options that meet identified need

Table 39 presents the cost, and weighted gross and net market benefits in NPV, for each of the four credible options. The NPV of these net market benefits assumes the benefits continue beyond 2033-34, as discussed in Section 5.2.1, and primarily arise from:

- Reduction in involuntary load curtailment that would otherwise be required to maintain system security.
- Reduction in market costs and emissions associated with market interventions (in the form of directing gas generation) that would otherwise be required to maintain system security.

Table 39 Weighted market benefits for each combined pillars augmentation option ($M)

Option	Description	Total network MVAr invested (excludes MVAr offered by non-network services)	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	45.6	285.9	256.4
Option 2	Capacitors and reactors, and non-network service in eastern metropolitan Melbourne	500	39.2	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	301.1	284.0	77.6
Option 4	Option 1 with one capacitor and one reactors displaced by one SVC in 2029	450	57.3	286.8	246.2

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

Option 1, consisting of a combination of reactors and capacitors, maximises net market benefits for consumers, and is therefore the preferred option in this PADR.

Comparing Option 1 against Option 2:

- The non-network service defers the need for one of the capacitors at East Metro, reducing the total capital cost by $6.4million. The non-network service does not defer the need for one of the reactors.
- With all 3 reactors in service, this non-network service does not deliver any additional gross market benefits associated with reducing out-of-merit dispatch but does still help reduce involuntary load shedding at times when under-voltages need to be managed.
- Therefore, once the operational and maintenance cost of the non-network service is taken into account, the net market benefits for Option 2 are slightly lower than for Option 1, despite deferring the need for investment in one capacitor at East Metro.

Comparing Option 1 against Option 3:

- A non-network option at Deer Park provides lower positive net benefits than installing a capacitor at Deer Park in 2031 and a capacitor in the east metro region in 2034, which this non-network option defers. This is due to the capital cost associated with the non-network option considered at Deer Park, which is greater than the capital cost of the displaced capacitors. A non-network option at Deer Park does not defer the need for one of the reactors.
- The non-network capital cost is included in the cost of this option because, unlike the non-network services in Option 2, this non-network service would be delivered from assets that are not yet committed or anticipated.
- Should this non-network service become committed, such that only the operating and maintenance costs associated with providing this service need be paid for by consumers, the net market benefits of this option would improve significantly.

Comparing Option 1 against Option 4:

- Analysis indicates that, while network options with both generating and absorbing reactive capability (in this example an SVC) are effective at reducing the overall MVAr investment required, this reduction is not significant enough to outweigh the increased cost of an SVC (capital cost of $33.1 million) compared with the combined cost of the one reactor and two capacitors that are displaced (combined capital cost of $21.4 million).

See Attachment B – Market Benefits[46] for more details on the gross and net market benefit calculations for each credible option. Section 6.4 below provides more insight into how the preferred option delivers net market benefits in the long-term interest of consumers.

AVP notes, as mentioned in Chapter 2, that the preferred solution does not replace the total 650 MVAr that will be removed from the metropolitan Melbourne system in 2027-28 as discussed in Section 2.2.7. This is due to a number of changes in the network over the next 10 years, such as:

- The commissioning of committed and anticipated BESS in locations that are effective at providing the reactive support traditionally provided by these capacitors.
- A change in the operating configuration of the network following the retirement of Yallourn Power Station.

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

6.4 Market benefits of the preferred option

The preferred option that addresses both pillars of the identified need and maximises net market benefits for consumers is a staged option comprising:

- Stage 1: 3 x 100 MVAr reactors[47] on the 220 kV level in 2029;
- Stage 2: 1 x 100 MVAr capacitor for Deer Park 220 kV in 2031; and
- Stage 3: 2 x 100 MVAr capacitors for East Metro in 2034.

This option is estimated to deliver $256.4 million in net market benefits to consumers on a net present value basis and is staged to maximise flexibility in the event that market conditions change in future.

Figure 9 shows the annual gross benefits by market benefits class, as well as the investment cost and net market benefits of the preferred option. The market benefits reflect reductions in fuel (and start-up) costs, reductions in costs associated with involuntary load curtailment, and reductions in emission costs (noting that benefits in emission costs reductions for Pillar 1 are too small to be visible on the graph).

Figure 9 Annual gross benefits, investment cost and net market benefits of preferred option ($M)

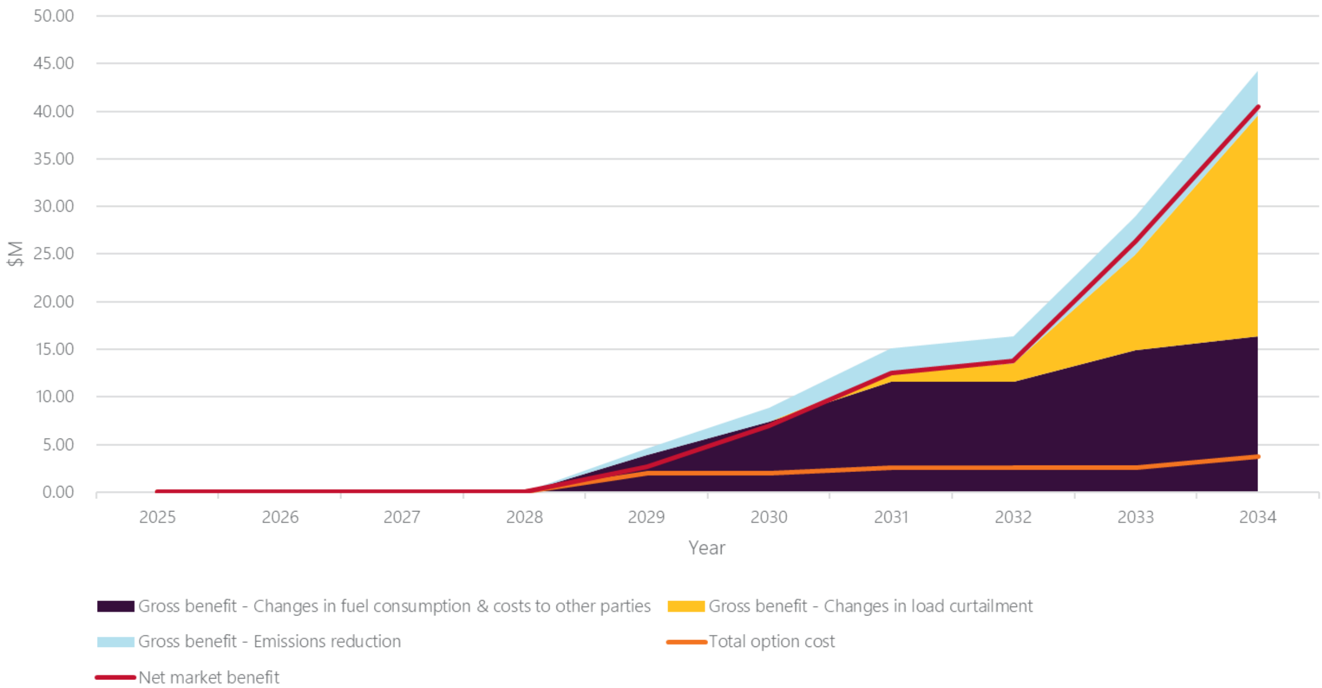


Figure 10 shows the projected annual hours of USE for the 'do nothing' base case and the proposed preferred option, which represent the number of hours of pre-contingent load shed.

[47] At a combination of South Morang, Thomastown, and West Melbourne.

Figure 10 Annual MWh of USE in do nothing (base case) versus preferred option

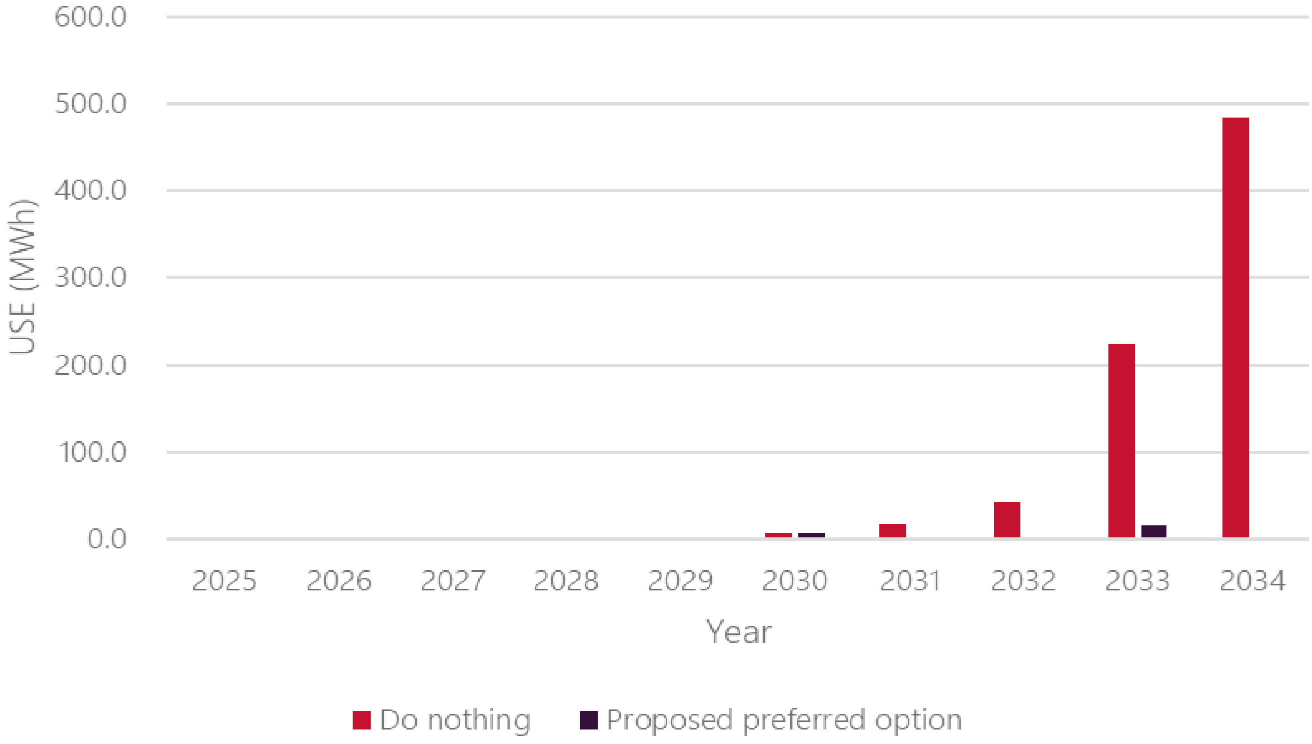


Figure 11 shows the projected annual hours of market intervention for the 'do nothing' base case and the proposed preferred option, which represent the total running hours of generators brought online for voltage management support.

Figure 11 Annual hours of intervention for do nothing (base case) and proposed preferred option

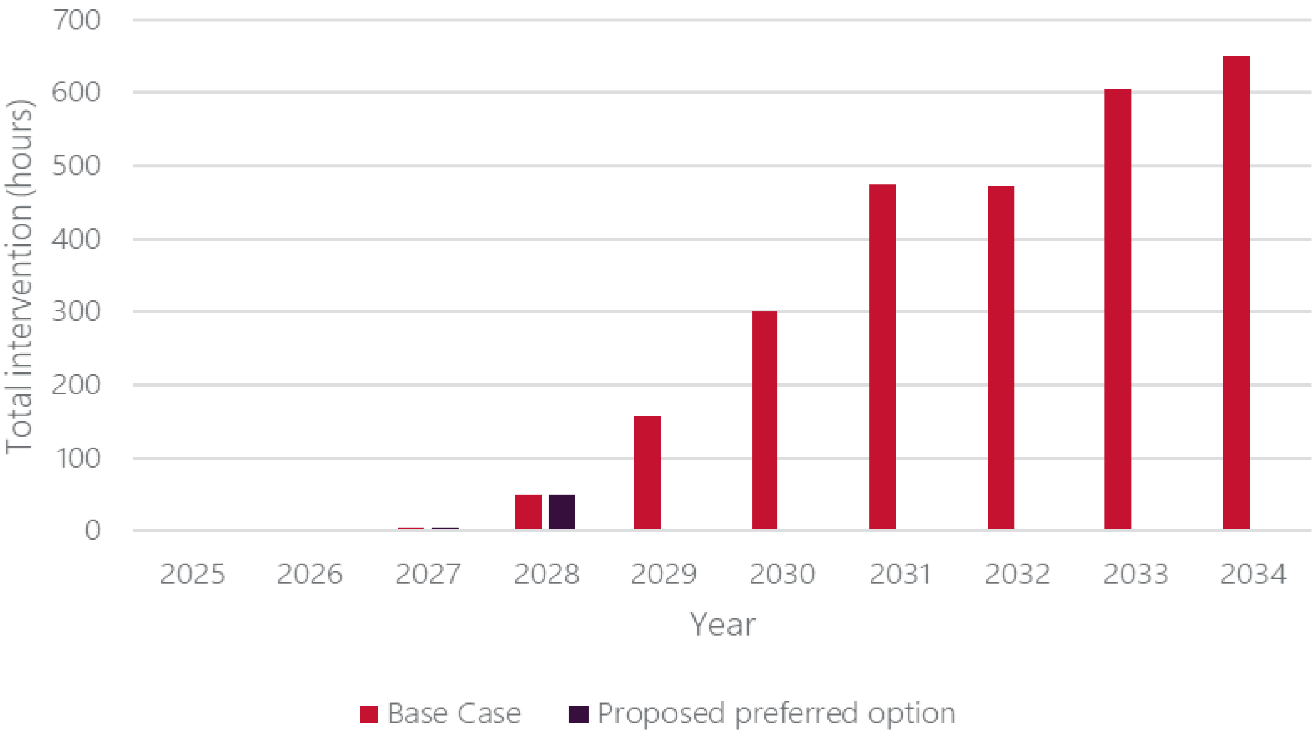


Figure 12, Figure 13 and Figure 14 show the annual maximum demand forecasts for the 2023 ESOO Central scenario for 10% POE, and the respective maximum supportable demand for the relevant load areas for Pillar 1 across the modelling period, for the 'do nothing' base case and for the proposed preferred option.

In these figures, where the connection point forecast exceeds the maximum supportable demand is where USE 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 USE 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.

Figure 12 Pillar 1 Option 1 maximum supportable demand for Deer Park 220 kV (MW)

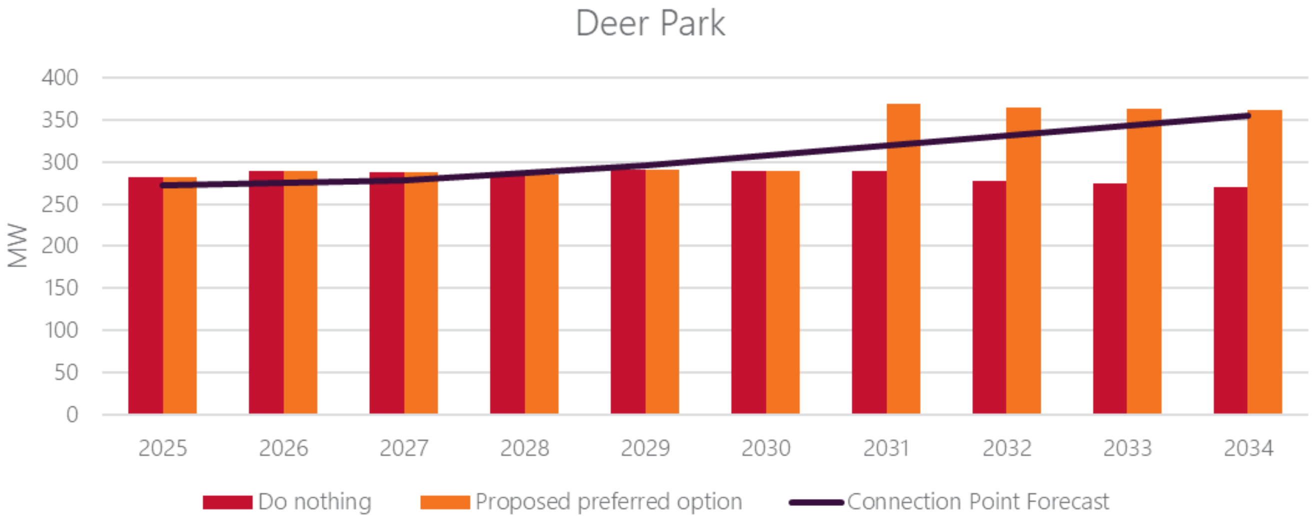


Figure 13 Pillar 1 Option 1 maximum supportable demand for Tyabb 220 kV (MW)

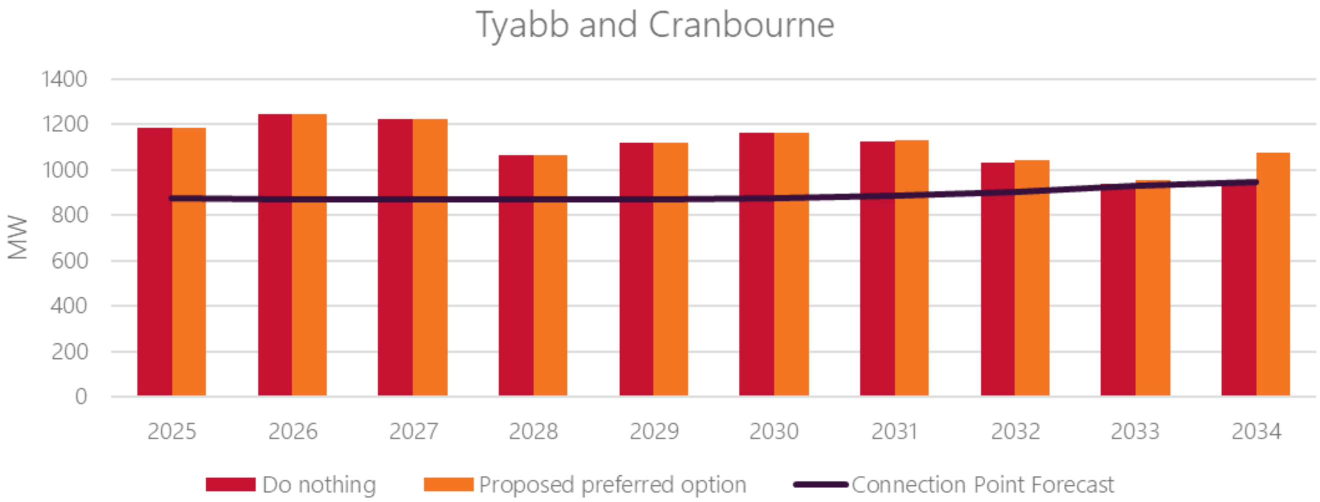
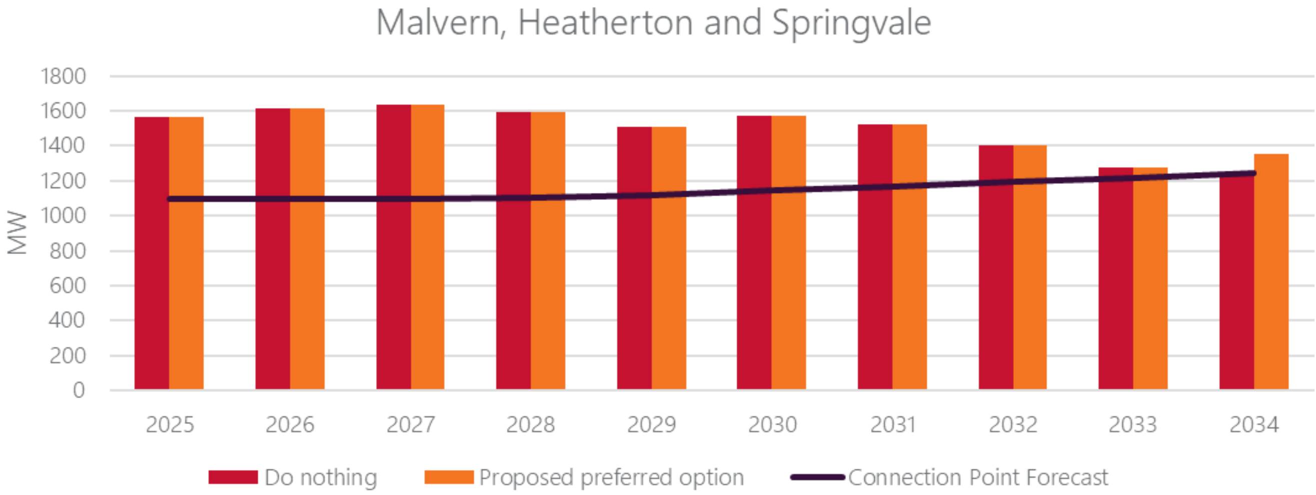


Figure 14 Pillar 1 Option 1 maximum supportable demand for Rowville 220 kV (MW)



6.5 Sensitivity studies

The following sensitivity analysis was carried out to test the robustness of the analysis resulting in the preferred option, and to determine if any factors would change the investment size and timing of individual components. Where material impacts are observed, these will be revisited in the PACR as the likelihood of these sensitivity scenarios eventuating becomes more apparent. Staged procurement of the proposed preferred option will also enable AVP to monitor the progression of future network and generator developments, and prevailing market conditions and demand forecasts, such that AVP is satisfied that the identified need still remains and changes in the market or the power system have not eroded the net market benefits for consumers.

Preferred options identified in other currently progressing Victorian RIT-Ts or planned developments such as AVP's System Strength RIT-T[48], AusNet's RIT-T to maintain reliable services at South Morang[49], or CitiPower/Powercor's possible developments to upgrade transfer capacity at Deer Park, are some of the future developments that may help address the identified voltage management needs and subsequently erode net market benefits for consumers, which a staged delivery of the preferred option of this voltage management RIT-T would help manage. Some of these developments and others are explored in the sensitivity studies below. As part of the PACR, AVP will also investigate the impact of AusNet Services' ongoing RIT-T at South Morang Terminal Station.

Change in cost

This sensitivity explored the impact of capital costs changing by ±30%. It results in no impact to the identified need described in Chapter 2 and does not change the preferred option, its investment size nor timing, however it does affect the NPV of net benefits, as follows:

For 30% higher costs, Table 40 details the relative net market benefits for all four options. The preferred option:

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[48] At https://aemo.com.au/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission.

[49] At https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/about/regulatory-investment-test/2024/smts-gis-replacement-pscr_v1.pdf?rev=f8457e3fa8db47febf526f87e030d23c&hash=27D6F2B640A203632C6CD7E56B01694A.

- For Pillar 1, has total net benefits of $118.7 million.
- For Pillar 2, has total net benefits of $128.8 million.

Under the 30% increase in capex sensitivity, the net benefit calculation highlights that the optimal sizing would be with a 1 x 100 MVAr capacitor at East Metro instead of the 2 x 100 MVAr specified as the optimal sizing in Table 22.

For 30% lower costs, Table 41 details the relative net market benefits for all four options. The preferred option:

- For Pillar 1, has total net benefits of $125.3 million.
- For Pillar 2, has total net benefits of $139.9 million.

This indicates that the proposed preferred option of this PADR is robust against changes in cost by ±30% and will have positive net benefits with costs in this range.

Table 40 Weighted market benefits for each combined pillars with 30% higher costs

Option	Description	Total network MVAr invested (excludes MVAr offered by non-network services)	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	59.3	284.8	250.6
Option 2	Capacitors and reactors, and non-network service in eastern metropolitan Melbourne	500	51.0	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	391.4	263.5	-5.0
Option 4	Option 1 with one capacitor and one reactors displaced by one SVC in 2029	450	74.4	286.8	233.8

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

Table 41 Weighted market benefits for each combined pillars with 30% lower costs

Option	Description	Total network MVAr invested (excludes MVAr offered by non-network services)	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	31.9	285.9	265.2
Option 2	Capacitors and reactors, and non-network service in eastern metropolitan Melbourne	500	27.4	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	210.7	263.5	119.1
Option 4	Option 1 with one capacitor and one reactors displaced by one SVC in 2029	450	40.1	286.8	258.6

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

Change in discount rate

This sensitivity explored the impact of a change in the base discount rate from 7% to a lower bound discount rate of 3% and an upper bound discount rate of 10.5%. It results in no impact to the identified need described in Chapter 2 and does not change the preferred option, its investment size or timing, however it does affect the NPV of net benefits.

Under a 3% discount rate, Table 42 details the relative net market benefits for all four options. The preferred option:

- For Pillar 1, has total net benefits of $231.1 million.
- For Pillar 2, has total net benefits of $258.4 million.

Under a 10.5% discount rate, Table 43 details the relative net market benefits for all four options. The preferred option:

- For Pillar 1, has total net benefits of $73.3 million.
- For Pillar 2, has total net benefits of $82.5 million.

This indicates that the proposed preferred option of this PADR is robust against changes in the discount rate and will have positive net benefits with a discount rate within these bounds.

Table 42 Weighted market benefits for each combined pillars with 3% discount

Option	Description	Total network MVAr invested (excludes MVAr offered by non-network services)	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	45.6	544.4	489.5
Option 2	Capacitors and reactors, and non-network service in eastern metropolitan Melbourne	500	39.2	540.7	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	301.1	494.1	127.7
Option 4	Option 1 with one capacitor and one reactors displaced by one SVC in 2029	450	57.3	550.4	476.0

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

Table 43 Weighted market benefits for each combined pillars with 10.5% discount

Option	Description	Total network MVAr invested (excludes MVAr offered by non-network services)	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	45.6	174.3	155.8
Option 2	Capacitors and reactors, and non-network service in	500	39.2	173.2	Confidential[A] (but less than the net market benefits of Option 1)

Option	Description	Total network MVAr invested (excludes MVAr offered by non-network services)	Capital cost ($M)	Combined Pillars weighted gross market benefit in NPV $M	Combined Pillars weighted net market benefit in NPV $M
	eastern metropolitan Melbourne				
Option 3	Capacitors and reactors, and non-network option at Deer Park	400	301.1	162.4	30.4
Option 4	Option 1 with one capacitor and one reactors displaced by one (SVC in 2029	450	57.3	174.1	148.1

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

Impact of publicly announced connection projects

This sensitivity explored the impact of additional reactive support from publicly announced BESS connection projects[50] in the metropolitan Melbourne area, were they to become anticipated or committed.

Unlike the first two sensitivities above, this sensitivity does impact the identified need and the possible over- and under-voltages observed during high demand and low demand periods respectively.

Considering these publicly announced connection projects, the preferred option may:

- For Pillar 1, require no investment as the additional reactive capability from these connection projects addresses much of the Pillar 1 Identified Need such that investment cannot be justified for the remaining need at Deer Park 220 kV.
- For Pillar 2, require only one 220 kV 100 MVAr reactor.

In total, this would result in $37 million less capital investment in network solutions, compared to the proposed preferred option, however there is no certainty that this private investment will eventuate.

This indicates that the commissioning of future connections may impact the proposed preferred option of this PADR. AVP will monitor and provide updates in the PACR as more connections become anticipated or committed. In general, uncertainty surrounding the number of capacitors and/or reactors needed in this RIT-T will be addressed through the proposed staging of the preferred option. Procurement of subsequent stages may be deferred if the identified need reduces.

Impact of ongoing System Strength RIT-T

This sensitivity explored the impact of any potential solutions with reactive capability (in areas where reactive support would be effective at meeting either Pillar such as those presented in Table 12 and Table 13 in Section 3.1) from AVP's ongoing System Strength RIT-T. One such area that is also required to meet the system

[50] From the May 2024 update of AEMO's Generation Information, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

strength standard is Hazelwood, where the other areas identified in the System Strength PSCR[51] are less correlated with the locations of this RIT-T's voltage management needs.

This sensitivity also impacts the identified need and the possible over- and under-voltages observed during high demand and low demand periods respectively.

This sensitivity considered the delivery of a synchronous condenser at Hazelwood 500 kV as an example of what could be delivered through the system strength RIT-T. In this sensitivity, the preferred option was found to require one fewer 220 kV 100 MVAr reactors. Assuming the system strength RIT-T delivers a synchronous condenser (estimated to cost $135 million) in 2030, this synchronous condenser would need to be brought forward by one year to effectively displace one of these reactors. This means, while bringing this synchronous condenser forward a year would defer the full cost of one reactor (with a capital cost of $8.62 million and a total cost of $19.68 million over its full payback period with a 7% discount rate), it would also result in a bring forward cost of one year for this synchronous condenser of $10.3 million (assuming 7% discount rate and an asset life of 30 years).

Bringing forward a synchronous condenser would therefore reduce capital investment in this RIT-T by $8.62 million, and would reduce the total option cost over its payback period by $9.41 million.

The decision to defer one reactor by bringing forward a synchronous condenser to meet system strength needs depends on the likelihood of a synchronous condenser forming part of the system strength RIT-T preferred option and also its timing for delivery that this RIT-T could bring it forward from.

AVP will provide further update in the PACR on the likelihood and timing of a synchronous condenser forming part of the System Strength RIT-T preferred option, and if there is benefit in bringing this synchronous condenser forward to meet the Identified Need of this RIT-T and defer parts of its proposed preferred option identified in Chapter 6 and summarised in Chapter 7.

Impact of possible upgrades to thermally constrained transmission lines between eastern and western metropolitan Melbourne and significant supply hubs in Victoria

This sensitivity explored the impact of any potential solutions to alleviate thermal constraints in eastern and western metropolitan Melbourne.

This sensitivity impacts Pillar 1 of the identified need only as these thermal constraints typically occur during high demand conditions and not during low demand conditions.

Considering these upgrades remove the critical contingencies for the critical sites – the Pillar 1 needs may reduce to no capacitors needed.

This indicates that the delivery of the solutions to alleviate these thermal constraints may impact the proposed preferred option of this PADR, and AVP will monitor this and provide updates in the PACR as ongoing pre-feasibility studies on these thermal constraints progress.

[51] See https://aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength---project-specification-consultation-report_final.pdf?la=en.

Impact of future Victorian BESS fleet charging at times of low demand

For the main assessments included in Section 6.3 of this PADR, AVP assumed BESS charge/discharge of 0 MW at time of minimum demand.

This sensitivity explored the impact of currently existing, committed, anticipated, and other future BESS as explored in the *Publicly Announced Connections* sensitivity above, charging at times of low demand.

This sensitivity impacts Pillar 2 of the identified need only.

Considering a future Victorian BESS fleet charging at an arbitrary output of 25% of maximum charging capacity, the preferred option may, for Pillar 2 (and thus also for the overall option), require only one 220 kV 100 MVAr reactor (while this results in the same outcome as the *Publicly Announced Connections* sensitivity above, it would deliver fewer gross market benefits than the reactor required in the *Publicly Announced Connections* sensitivity).

This indicates that a future Victorian BESS fleet charging at times of low demand may impact the preferred option of this PADR, and AVP will monitor this and provide updates in the PACR.

7 Proposed preferred option

The proposed preferred option is to install 3 x 100 MVAr reactors on the 220 kV level across various sites in metropolitan Melbourne, and 3 x 100 MVAr capacitors, one each at Deer Park, Malvern and Tyabb on the 220 kV level.

The NER require the PADR to identify the preferred option under the RIT-T, which is the investment option that meets an identified need while maximising the present value of net economic market benefits to all those who produce, consume, and transport electricity in the market.

The RIT-T analysis discussed in Chapter 5 indicates that the staged proposed preferred option identified in this PADR is to install:

Stage 1:

- 1 x 100 MVAr shunt reactor at South Morang Terminal Station on the 220 kV level in 2029.
- 1 x 100 MVAr shunt reactor at Thomastown Terminal Station on the 220 kV level in 2029.
- 1 x 100 MVAr shunt reactor at West Melbourne Terminal Station on the 220 kV level in 2029.

Stage 2:

- 1 x 100 MVAr shunt capacitor at Deer Park Terminal Station on the 220 kV level in 2031.

Stage 3:

- 1 x 100 MVAr shunt capacitor at Malvern Terminal Station on the 220 kV level in 2034.
- 1 x 100 MVAr shunt capacitor at Tyabb Terminal Station on the 220 kV level in 2034.

The proposed preferred option has a capital cost of approximately $45.6 million (in present value terms), and yields the highest net market benefits when weighted across all reasonable scenarios and sensitivities.

The PADR analysis identifies that investing in this option will deliver a net present economic market benefit of approximately $256.4 million, by:

- Reducing costs of involuntary load shedding that would otherwise need to occur during high demand periods to manage under voltage risks; and
- Reducing fuel, operating and maintenance (O&M) and emission costs that would otherwise be incurred through dispatch of additional thermal generators to manage over-voltages during light load periods.

Together, the above listed augmentations constitute the proposed preferred option and satisfy the regulatory investment test for transmission.

Table 44 presents indicative timeframes for the latest that option construction should commence for delivery of Stage 1 investments by the optimal timings stated above, based on lead times presented in Section 3.6.

Table 44 Indicative construction timelines (task completed by beginning of the quarter included)

Task description	Static reactive plant
Regulatory investment process	Q2-2024 to Q4-2024
Contract negotiation	Q1-2025 to Q3-2025
Design, approvals and long lead procurement	Q4-2025 to Q2-2027
Construction	Q3-2027 to Q3-2028
Commissioning and delivery	Q4-2028 to Q3-2029

This option may be refined in the PACR as generator and BESS connections in areas where reactive support is effective become anticipated or committed.

AVP continues to welcome submissions to this RIT-T in the consultation period from 26 July 2024 to 6 September 2024, particularly on network or non-network options that may refine the proposed preferred option between now and the next and final stage of this RIT-T, the PACR.

A1. Compliance checklist

Rules clause	Summary of requirements	Relevant section(s) in PADR
5.16.4(k)	(1) a description of each credible option assessed;	Section 3.5
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Chapter 4
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	Chapter 3.6
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Chapter 5
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Section 6.1
	(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;	Section 6.3
	(8) the identification of the proposed preferred option;	Chapter 7
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i)details of the technical characteristics; (ii)the estimated construction timetable and commissioning date; (iii)if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv)a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission; and	Chapter 7