AEMO
AUSTRALIAN ENERGY MARKET OPERATOR
Victorian Planning

Metropolitan Melbourne Voltage Management

October 2023

Regulatory Investment Test for Transmission (RIT-T)

Project Specification Consultation Report (PSCR)

Important notice

Purpose

AEMO has prepared this Project Specification Consultation Report to meet the consultation requirements of clause 5.16.4(b) of the National Electricity Rules.

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Executive summary

The Victorian Declared Shared Network (DSN), like the National Electricity Market (NEM) more generally, is undergoing transformational changes with the withdrawal of several existing coal and gas-fired generation sources, an unprecedented increase in renewable generation and consumer energy resources (CER) and changes in consumption patterns.

Maximum operational electricity demand in Victoria is forecast to grow and minimum operational electricity demand is forecast to decline. In addition, aging equipment that provides reactive power support during maximum demand times is approaching retirement, in particular capacitors located at terminal stations in the metropolitan Melbourne area.

These trends are increasing the need for additional reactive power support for voltage control. Voltage control acts to maintain voltages at different points in the network within acceptable ranges during normal operation, and to enable recovery to acceptable levels following a disturbance. Acceptable voltage ranges are defined in the NER[1].

Voltage control is managed through balancing the production or absorption of reactive power. Reactive power does not 'travel' far, meaning it is generally more effective to address reactive power imbalances locally, close to where it is required. Adequate reactive power reserves need to be maintained to ensure the security of the transmission system in the event of a credible contingency.

AEMO operates the power system to maintain voltage levels across connection points in the transmission network within limits set by Network Service Providers and to a target voltage range. This involves the coordination of available reactive power resources in the network and from generators. If voltages still remain outside their technical limits, other tools available to system operators include:

- Network reconfiguration – operational switching of transmission elements in and out of service to rebalance reactive power production and absorption. For example, in Victoria, 500 kilovolt (kV) lines can be de-energised to maintain voltages within operational limits during low demand periods.
- Contracts with Transmission Network Service Providers (TNSPs) and generators – agreements for specific reactive support under specific circumstances.
- Load shedding – automatic or manual load shedding as an emergency last resort.

AVP is forecasting that such measures may be necessary at Deer Park Terminal Station as early as this year, to enable recovery to acceptable voltage levels following a disturbance, if this disturbance occurs during demand conditions similar to the distribution network service provider's 1-in-10 year maximum demand forecasts. Based on the likelihood of a contingency event occurring during a 1-in-10 year maximum demand, AVP does not consider that investment to provide additional reactive power support to Deer Park under these conditions would be beneficial for consumers. Further, it is noted that the 1-in-10 year maximum demand forecasts at Deer Park are significantly higher than the historical maximum demand levels observed, or the current N-1 transformer import rating at this terminal station[2].

[1] AEMC. Schedule 5.1A, at https://energy-rules.aemc.gov.au/ner/491

[2] Jemena, CitiPower, Powercor, AusNet, United Energy; 2022 TCPR, p.97, at https://jemena.com.au/documents/electricity/2022-tcpr.aspx

However, given the forecast trends in maximum and minimum demand, and forecast decline in reactive power reserves, AVP forecasts that investment for greater management of reactive power will be necessary at Deer Park and other connection points within the next decade. Options for both production and absorption of reactive power will be needed to ensure network voltage levels remain within required limits, which is in turn essential for maintaining power system security and reliability.

Regulatory Investment Test for Transmission (RIT-T)

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

In response to the concerns outlined above, AVP is undertaking this metropolitan Melbourne Voltage Management RIT-T to assess network and non-network investment options that are considered technically and economically feasible to meet the identified need described below. Through the assessment of credible options, the RIT-T process will identify a proposed preferred option, then ultimately a preferred option and its optimal timing.

This Project Specification Consultation Report (PSCR) is the first stage of the RIT-T process, and includes:

- A description of the identified need, and assumptions used in identifying that identified need.
- The technical characteristics and performance requirements that a non-network option would have to deliver to meet the identified need.
- A description of all credible options AVP is aware of that address the identified need, including, for each credible option, its technical characteristics, whether it is reasonably likely to have a material inter-network impact, the classes of market benefits AVP considers not likely to be material (and why), and the estimated construction timeline, commissioning date and indicative capital and operating and maintenance costs.

Identified need to invest

AVP has identified a need to invest to manage DSN voltages within operational and design limits in the metropolitan Melbourne region in Victoria. The indicative timing for this investment is 2027-28, when existing capacitors located at terminal stations in the metropolitan Melbourne area are due to retire and it is anticipated that investment can be economically justified and delivered. The optimal timing for investment will be determined as part of the RIT-T. In the short term, as maximum and minimum demand at connection points in metropolitan Melbourne continue to set new records, AVP and AEMO (as system operator) will manage voltages within limits through operational measures and through joint planning with DNSPs.

The identified need can be broken into two pillars:

- **Identified Need Pillar One – the need to manage under-voltages**: AVP has identified a need to maintain the power system in a satisfactory and secure operating state[3] in metropolitan Melbourne during high demand periods, when voltages are at risk of falling below limits if a disturbance (credible contingency event) were to occur.
- **Identified Need Pillar Two – the need to manage over-voltages**: AVP has identified a need to maintain the power system in a satisfactory and secure operating state[3] in metropolitan Melbourne during low demand

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

periods, when voltages are at risk of rising above limits if a disturbance (credible contingency event) were to occur.

The identified need has been broken into two separate pillars because, while the identified need is to maintain the power system in a satisfactory and secure operating state by managing DSN voltages to within limits, there are two distinct drivers of this identified need:

- The driver of the first identified need pillar is increasing operational demand levels during high demand periods in the general metropolitan Melbourne area, coupled with retirement of reactive power plant. While the available reactive capacity of grid-scale storage in metropolitan Melbourne is forecast to increase, and a proposed network reconfiguration of the Latrobe Valley with retirement of Yallourn Power Station in mid-2028 will help support metropolitan Melbourne voltage levels, the retirement of 650 megavolt ampere reactive (MVAr) of capacitors in metropolitan Melbourne in 2027-28 is forecast to result in a net decline in reactive support reserves during maximum demand periods.
- The driver of the second identified need pillar is decreasing operational demand levels during low demand periods in the general metropolitan Melbourne area, coupled with fewer generators capable of absorbing reactive power being online as CER such as distributed photovoltaic (PV) generators increasingly displace grid-scale generators.

Credible options

AVP is considering various options to address both pillars of the identified need through this RIT-T. The preferred option will be required to address the identified need and maximise net market benefits to all those who produce, consume and transport electricity in the NEM.

The options AVP considers can address **Identified Need Pillar One** are:

- Demand side participation in the form of voluntary load reduction.
- 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 investment sufficient to allow transmission system under-voltages to be managed within existing operational voltage limits and to enable voltage recovery to acceptable levels following a disturbance, such as additional generating reactive support in the form of capacitors or dynamic plant such as synchronous condensers, static synchronous compensators (STATCOMs) or static VAR compensators (SVCs).
- Further battery energy storage system (BESS) grid connections in the right locations with available reactive support.

The options AVP considers can address **Identified Need Pillar Two** are:

- Directing BESSs to charge to increase network load during minimum demand periods.
- Network investment to upgrade existing transmission assets, such as the Keilor 500/220 kV transformers, that are currently limiting over-voltage levels below NER limits.
- Network investment sufficient to allow transmission system over-voltages to be managed within existing operational voltage limits, such as additional absorbing reactive support in the form of reactors or dynamic plant such as synchronous condensers, STATCOMs or SVCs.

Possible combinations of network investment options for additional reactive support (at a high level) to meet the identified needs include:

- Capacitors (+) and reactors (-) only.
- Capacitors (+) and a single dynamic reactive plant (±).
- Capacitors (+) and two dynamic reactive plants (±).

There are a large number of possible location combinations, given that investment in reactive support does not necessarily need to occur at the direct sites where the voltage management issues have been identified, but is most effective when located nearby. In this PSCR, AVP has, for illustrative purposes, developed portfolios of network options for additional reactive support to meet the identified need, using the transmission level locations most effective at addressing each need. These illustrative portfolios of options do not necessarily translate to being the most economically efficient combination that maximises benefit for consumers, which will be identified at the Project Assessment Draft Report (PADR) stage.

Table 1 gives a preliminary indication of the MVAr investment required on an annual basis for the next five years (considering this illustrative portfolio option of locations) to keep transmission voltages within existing limits for both high and low voltage conditions, with an additional projection for ten years from today. The optimal timing for any investment will be determined through the RIT-T options analysis, and voltages will continue to be managed operationally prior to any investment.

Table 1 Possible mix of MVAr investment to meet the identified need, for a select combination of locations

	Need location	Technology type	Indicative MVAr support required [A, B]					
			2023-24	2024-25	2025-26	2026-27	2027-28 [C]	2032-33
Combination 1	Deer Park 220 kV	Capacitor	+100	+100	+100	+150	+150	+200
	Tyabb 220 kV	Capacitor	-	-	-	-	-	+150
	Keilor 500 kV	Reactor	-	-150	-300	-500	-350	-750
Combination 2	Deer Park 220 kV	Dynamic reactive plant	±100	±100	±100	±150	±150	±200
	Tyabb 220 kV	Capacitor	-	-	-	-	-	+150
	Keilor 500 kV	Reactor	-	-100	-250	-400	-250	-650
Combination 3	Deer Park 220 kV	Dynamic reactive plant	±100	±100	±100	±100	±150	±200
	Tyabb 220 kV	Capacitor	-	-	-	-	-	+100
	Keilor 500 kV	Dynamic reactive plant	-	±100	±250	±400	±250	±650

A. Optimal timing for investment will be determined through the RIT-T
B. Values shown in Table 1 represent the total equivalent MVAr support required for each year and are not cumulative.
C. In 2027-28, when Yallourn retires, the minimum synchronous generating combination of four Loy Yang units and one Newport unit is assumed, which improves transmission voltages and reduces the observed gap, even after accounting for the retirement of the existing capacitors in that year. If this latter combination of synchronous generation is assumed for years 2024-25, 2025-26, and 2026-27, then the observed gap for the respective year would be less than as shown.

The proposed preferred solution to be identified in the PADR could consist of network options, non-network options, or a combination of both, and could be located at sites other than those illustrated in Table 1, if it is more beneficial to consumers to do so.

Submissions

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

Submissions should be emailed to AVP_RIT-T@aemo.com.au with subject title 'Metropolitan Melbourne Voltage Management PSCR' and are due on or before 5pm 31 January 2024.

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

Next steps

Following consultation on this PSCR, the next stage of the RIT-T process, in accordance with the requirements of clause 5.16.4 of the NER, is a full options analysis and publication of the PADR, which is planned for the first quarter of 2024.

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1 Introduction

This Project Specification Consultation Report (PSCR) has been prepared in accordance with the requirements of clause 5.16 of the National Electricity Rules (NER), for a Regulatory Investment Test for Transmission (RIT-T).

In line with these requirements, this PSCR provides:

- A description of the identified need and the assumptions used in identifying that identified need.
- The technical characteristics and performance requirements that a non-network option would have to deliver to meet the identified need.
- A description of all credible options which AVP is aware of that address the identified need including, for each credible option, its technical characteristics, whether it is reasonably likely to have a material inter-network impact, the classes of market benefits AVP considers not likely to be material (and why), and the estimated construction timeline, commissioning date and indicative capital and operating and maintenance costs of each credible option.

Following consultation on this PSCR, the next stage of the RIT-T process is a full options analysis and publication of the Project Assessment Draft Report (PADR), in accordance with the requirements of clause 5.16.4 of the NER.

The PADR will include information on the proposed preferred option that maximises net market benefits, further details on its technical characteristics and estimated construction timetable and commissioning date, and analysis showing that the proposed preferred option satisfies the RIT-T.

The third and final stage of the RIT-T process, the Project Assessment Conclusions Report (PACR), will make a conclusion on the preferred option taking into consideration feedback provided during the PADR consultation process.

2 Identified need

2.1 Background

The Victorian Declared Shared Network (DSN), like the National Electricity Market (NEM) more generally, is undergoing transformational changes with the withdrawal of several existing coal and gas-fired generation sources, an unprecedented increase in renewable generation and consumer energy resources (CER) and changes in consumption patterns.

Maximum operational electricity demand in Victoria is forecast to grow and minimum operational electricity demand is forecast to decline. In addition, aging equipment that provides reactive power support during maximum demand times is approaching retirement, in particular capacitors located at terminal stations in the metropolitan Melbourne area.

These trends are increasing the need for additional reactive power support for voltage control. Voltage control acts to maintain voltages at different points in the network within acceptable ranges during normal operation, and to enable recovery to acceptable levels following a disturbance. Acceptable voltage ranges are defined in the NER[4].

Voltage control is managed through balancing the production or absorption of reactive power. Reactive power does not ‘travel’ far, meaning it is generally more effective to address reactive power imbalances locally, close to where it is required. Adequate reactive power reserves need to be maintained to ensure the security of the transmission system in the event of a credible contingency.

AEMO operates the power system to maintain voltage levels across connection points in the transmission network within limits set by Network Service Providers and to a target voltage range. This involves the coordination of available reactive power resources in the network and from generators. If voltages still remain outside their technical limits, other tools available to system operators include:

- Network reconfiguration – operational switching of transmission elements in and out of service to rebalance reactive power production and absorption. For example, in Victoria, 500 kilovolt (kV) lines can be de-energised to maintain voltages within operational limits during low demand periods.
- Contracts with Transmission Network Service Providers (TNSPs) and generators – agreements for specific reactive support under specific circumstances.
- Load shedding – automatic or manual load shedding as an emergency last resort.

Drivers behind the inability to manage under-voltages

Increasing maximum operational electricity demand results in increased loading in the power system, which drives down voltage levels. Under-voltage occurs when voltage drops below acceptable levels. Ensuring sufficient generating reactive power capacity in the power system is one means of managing under-voltage. However, the generating reactive power available in the DSN for voltage management is also changing, with:

[4] AEMC. Schedule 5.1A, at https://energy-rules.aemc.gov.au/ner/491

- The withdrawal of conventional, synchronous generation sources which have large reactive power capability, and which are located in or close to areas with existing voltage stability limitations.
- Displacement of the above with variable wind and solar generation and battery energy storage systems (BESSs), which are commonly located in different areas, changing the locations of available reactive support.
- Existing reactive power service agreements, relating to exiting capacitor banks, approaching end of contract life.

Within the next 10 years, these trends are resulting in a forecast inability to manage transmission system under-voltages during high demand periods. This is particularly so in the metropolitan Melbourne area, with **low voltage stability in metropolitan Melbourne** being identified as an emerging limitation in AVP's 2022 *Victorian Annual Planning Report* (VAPR) at times of high demand within the 10-year VAPR planning horizon.

AVP is forecasting that high operational electricity demand will lead to low voltages below operational limits as early as this year at Deer Park Terminal Station, if demand conditions similar to the distribution network service provider's (DNSP) 1-in-10 year maximum demand forecasts were to eventuate and a credible contingency event were to occur at that time. Under such conditions, operational measures may be necessary to enable recovery to acceptable voltage levels following the disturbance

Based on the likelihood of a contingency event occurring during a 1-in-10 year maximum demand, AVP does not consider that investment to provide additional reactive power support to Deer Park under these conditions would be beneficial for consumers in the near term. AVP does however forecast that investment for greater management of reactive power will be necessary at Deer Park and other connection points within the next decade, as maximum operational electricity demand is forecast to grow and reactive power reserves are forecast to decline. Without adequate reactive power reserves, there is a greater risk of voltage instability (meaning the power system is unable to recover voltages to acceptable levels following a contingency event, and instead, there is an uncontrolled sustained change in voltages away from acceptable levels[5]).

Leaving voltage control unmanaged would pose a risk to the power system's ability to operate as intended, which would have implications for its ability to serve load and may ultimately result in loss of supply (either post-contingent or pre-contingent).

Drivers behind the inability to manage over-voltages

Decreasing minimum operational demand results in lightly loaded transmission lines in the system. Due to the natural capacitance of these transmission lines, they generate reactive power under light load conditions which subsequently lifts voltages throughout the power system without the flow of power to suppress these voltage increases. Over-voltage occurs when voltage rises above acceptable levels.

Ensuring sufficient absorbing reactive power capacity is one means of managing over-voltage issues. However, the absorbing reactive power available in the power system during minimum demand periods is changing, with:

- Increased penetration of distributed photovoltaic (PV) generation, which reduces transmission line flows resulting in increased capacitance from lightly loaded transmission lines.

[5] AEMO, Power System Stability Guidelines, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf?la=en.

- Existing distributed PV generators do not provide reactive power back to the transmission network, and are displacing conventional generators (such as coal and gas-fired units) that have historically provided that absorbing reactive power.

These trends are resulting in a forecast inability to manage transmission system over-voltages during low demand periods. This is particularly so in the metropolitan Melbourne area, with **High voltages in Metropolitan Melbourne and South West Victoria** being identified as an emerging limitation in AVP's 2022 VAPR, which identified the need for additional absorption reactive power by 2025.

If unmanaged, forecast low operational electricity demand will lead to high voltages exceeding operational limits as early as 2024-25. This poses a risk of damage to power system plant, and may subsequently require operational measures, such as the disconnection of multiple high-capacity transmission lines, to reduce excess capacitance (or generating reactive power) in the system[6].

2.2 Description of the identified need

AVP has identified a need to invest to manage DSN voltages within operational and design limits in the metropolitan Melbourne region in Victoria. The indicative timing for this investment is by 2027-28, when existing capacitors located at terminal stations in the metropolitan Melbourne area are due to retire and it is anticipated that investment can be economically justified and delivered. The optimal timing for investment will be determined as part of the RIT-T. In the short term, as maximum and minimum demand at connection points in metropolitan Melbourne continue to set new records, AVP and AEMO (as system operator) will manage voltages within limits through operational measures and through joint planning with DNSPs.

This identified need can be broken in to two pillars:

- **Identified Need Pillar One – the need to manage under-voltages**: AVP has identified a need to maintain the power system in a satisfactory and secure operating state[7] in metropolitan Melbourne during high demand periods when voltages are at risk of falling below limits if a disturbance (credible contingency event) were to occur
- **Identified Need Pillar Two – the need to manage over-voltages**: AVP has identified a need to maintain the power system in a satisfactory and secure operating state[3] in metropolitan Melbourne during low demand periods, when voltages are at risk of rising above limits if a disturbance (credible contingency event) were to occur.

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

- The driver of the first identified need pillar is increasing operational demand levels during high demand periods in the general metropolitan Melbourne area, coupled with retirement of reactive power plant. While the available reactive capacity of grid-scale storage in metropolitan Melbourne is forecast to increase and a proposed network reconfiguration of the Latrobe Valley with retirement of Yallourn Power Station in mid-2028 that help support metropolitan Melbourne voltage levels, the retirement of 650 megavolt amperes reactive

[6] The de-energisation of 500 kV lines in Victoria is an existing last resort operational measure for maintaining high transmission system voltages within operational limits during *low* demand periods.

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

(MVAr) of capacitor banks in metropolitan Melbourne in 2027-28 is forecast to result in a net decline in reactive support reserves during maximum demand periods.

- The driver of the second identified need pillar is decreasing operational demand levels during low demand periods in the general metropolitan Melbourne area, coupled with fewer generators capable of absorbing reactive power being online as CER, such as distributed PV generators, increasingly displace grid-scale generators.

These drivers may evolve differently in the future but are considered together in this RIT-T because they both fall under the same identified need to manage DSN voltage levels within limits, and so the benefits associated with solutions that can address both pillars, such as synchronous condensers, static synchronous compensators (STATCOMS) and static VAR compensators (SVCs), can sufficiently 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 below give an indication of the voltage exceedances that may occur under a do-nothing scenario, for high demand and low demand periods respectively.

In the short term, as maximum and minimum demand at connection points in metropolitan Melbourne continue to set new records, AVP and AEMO (as system operator) will manage voltages within limits through operational measures and through joint planning with DNSPs.

Table 2 Possible under-voltages under POE10 summer maximum demand in the next 10 years

Critical site	Low voltage limit (kV)	Possible post-contingent voltage level (kV) in next 10 years					
		2023-24	2024-25	2025-26	2026-27	2027-28	2032-33
Deer Park 220 kV	**209**	208	195	194	192	191	123
Tyabb 220 kV	**209**	>209	>209	>209	>209	>209	203
Rowville 220 kV	**209**	>209	>209	>209	>209	>209	209

Table 3 Possible over-voltages under POE90 minimum demand in the next 10 years

Critical site	High voltage limit (kV)	Possible post-contingent voltage level (kV) in next 10 years					
		2023-24	2024-25	2025-26	2026-27	2027-28	2032-33
Keilor 500 kV	**525**	<525	526	528	534	529	541

2.3 Assumptions used in identifying the identified need

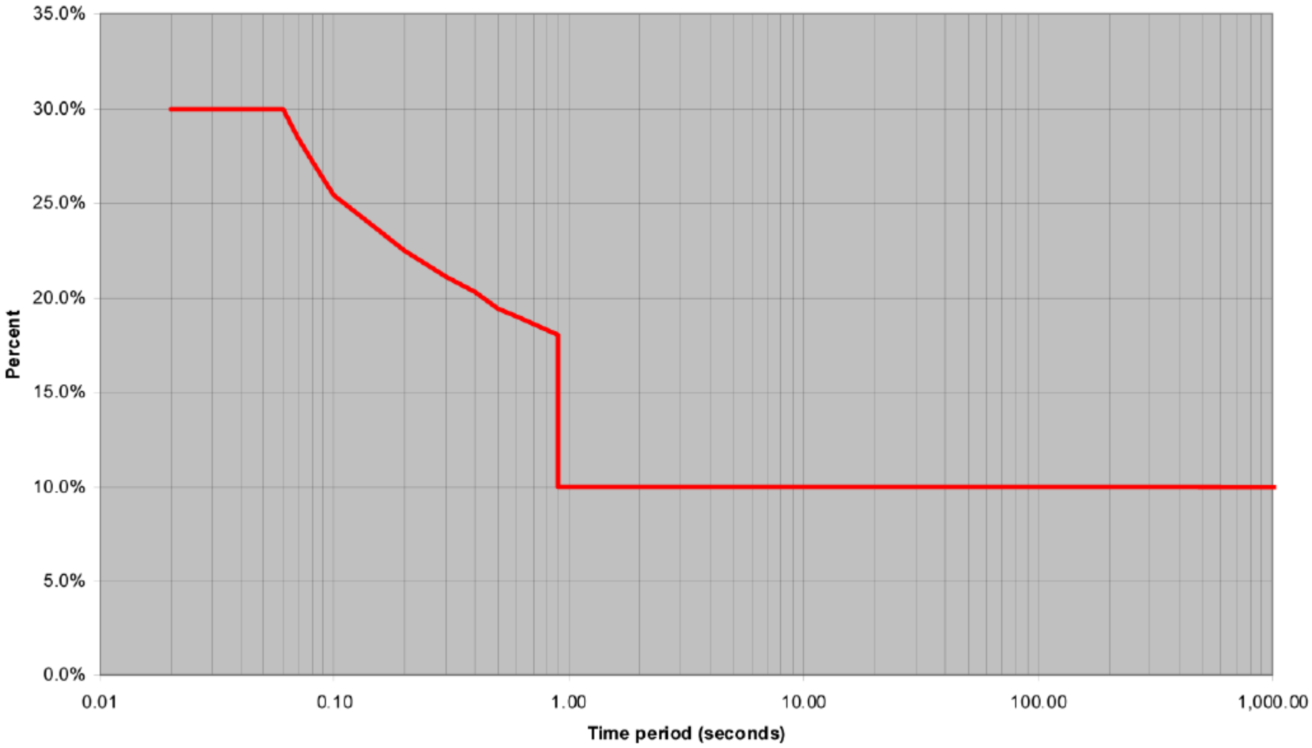
2.3.1 System standards and voltage limitations

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, except as a consequence of a contingency event, both under- and over-voltage levels must be maintained within 10% or normal voltages.

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.

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.

Table 4 shows the over-voltage site specific voltage limitations relevant to this PSCR, and Table 5 shows the under-voltage site specific voltage limitations relevant to this PSCR.

Table 4 Site specific over-voltage limitations

Location	Voltage limit	Limitation description
Keilor 500 kV	1.05 per unit of nominal voltage (525 kV)	Keilor 500/220 kV transformer limitation

Table 5 Site specific under-voltage limitations

Location	Voltage limit [A]	Limitation description
Deer Park 220 kV	0.95 per unit of nominal voltage (209 kV)	Operational limit to manage downstream voltage stability
Tyabb 220 kV	0.95 per unit of nominal voltage (209 kV)	Operational limit to manage downstream voltage stability
Rowville 220 kV area	0.954 per unit of nominal voltage (210 kV)	Operational limit to manage downstream voltages stability

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*.

2.3.2 Maximum demand forecast

Identified Need Pillar One – inability to manage under-voltages– has been assessed using AEMO's maximum operational demand forecast from the 2023 *Electricity Statement of Opportunities* (ESOO) Central scenario. 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

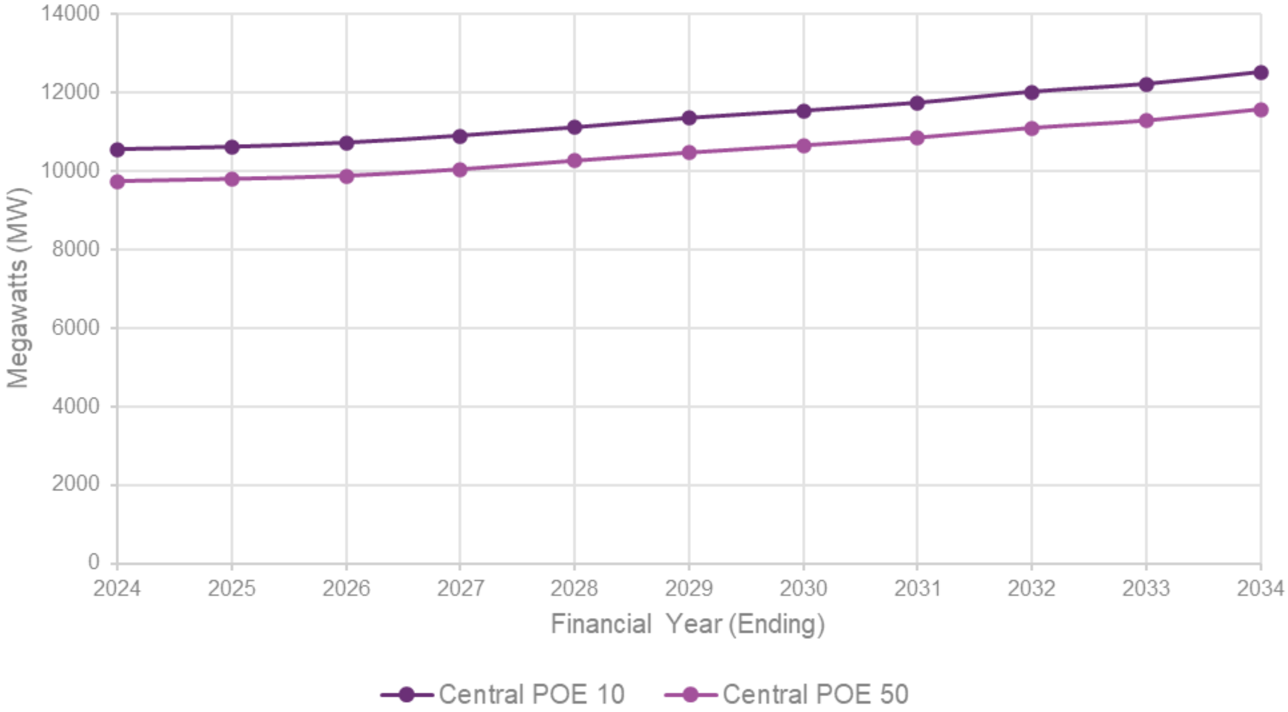
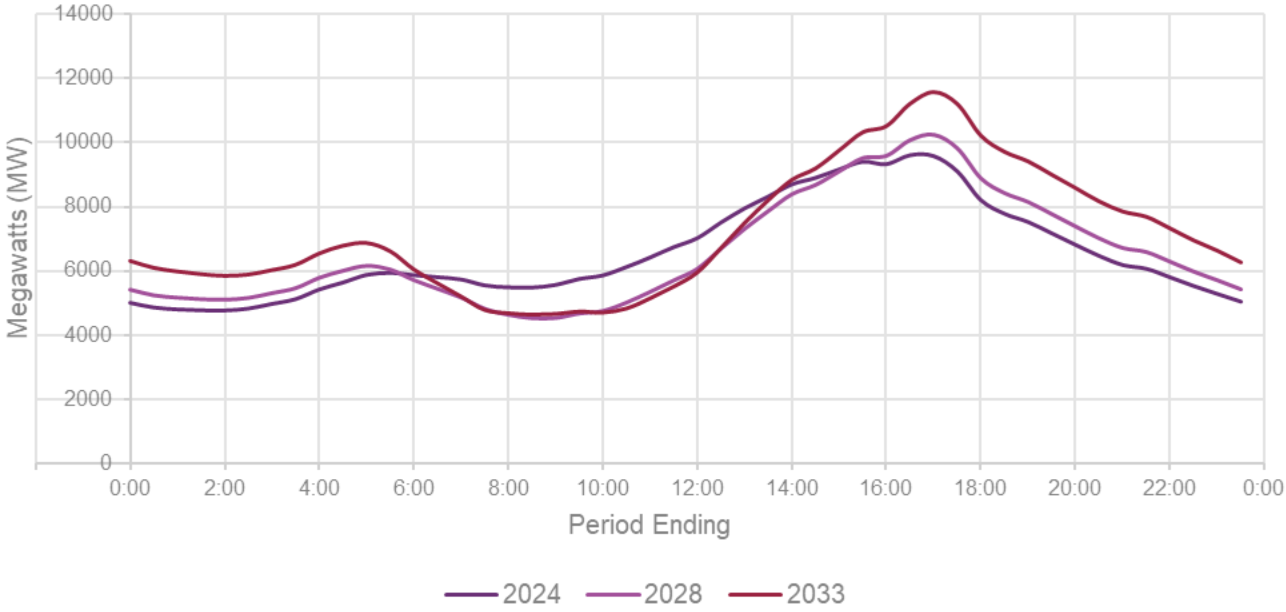


Figure 3 Forecast daily Victorian demand profile (FY2023) of maximum demand days in (FY ending) 2024, 2028, and 2033, Central scenario POE50



Notes: Period Ending given in Australian Eastern Standard Time. POE50 is 50% probability of exceedance.

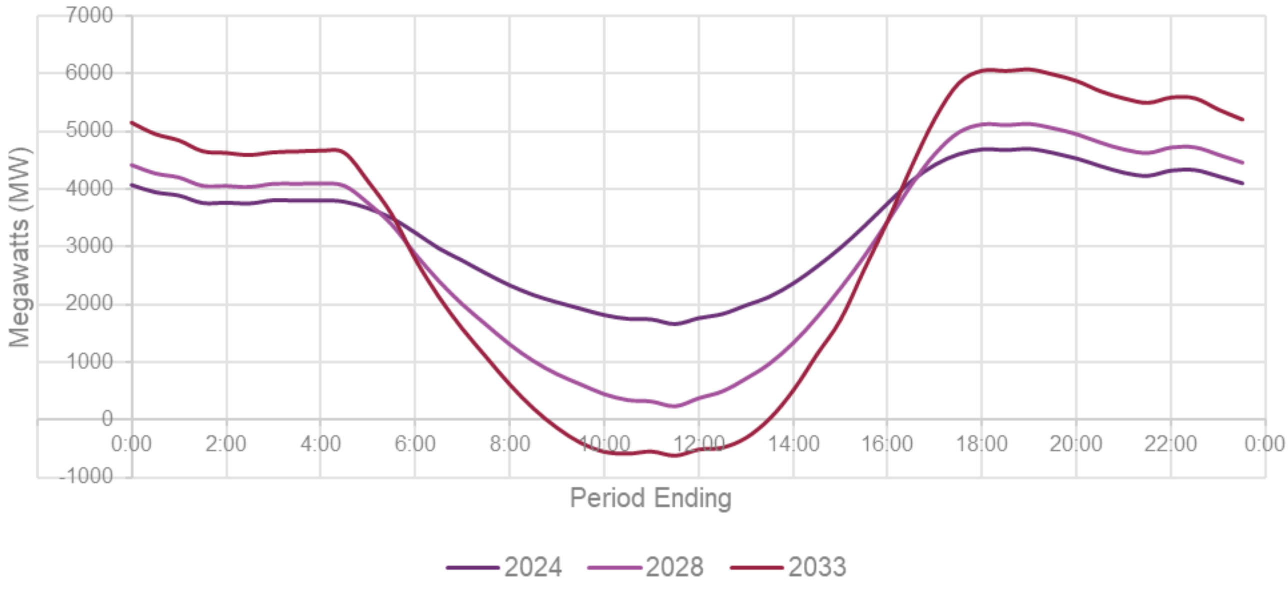
2.3.3 Minimum demand forecast

Identified Need Pillar Two – inability to manage over-voltages– has been assessed using AEMO's minimum operational demand forecast from the 2023 ESOO Central scenario. 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[8]. This reduction is mainly driven by a continued forecast increase in distributed PV installations reducing operational demand in the middle of the day. Figure 5 shows simulated 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 demand periods in the middle of the day (this is raw operational demand, meaning that it does not make any assumption regarding market-based solutions such as BESSs that may take advantage of these low demand periods to charge.)

[8] 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 4 Minimum operational demand forecast

Figure 5 Forecast daily Victorian demand profile (2022-23) of minimum demand days in (FY ending) 2024, 2028, and 2033, Central scenario POE50



Notes: Period Ending given in Australian Eastern Standard Time. POE50 is 50% probability of exceedance.

2.3.4 Transmission connection point demand forecasts

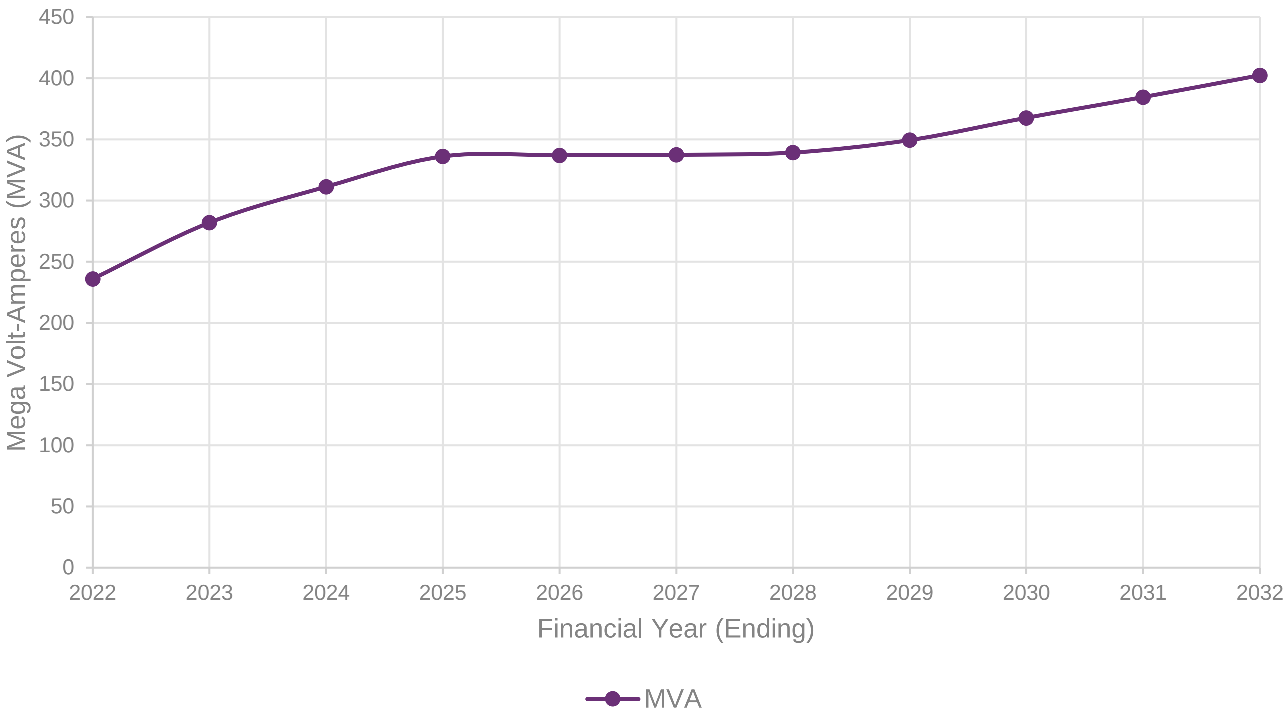
Individual transmission connection point demand (for both active and reactive power) will have a material influence on the locations and size of the identified reactive power shortfalls in metropolitan Melbourne presented in this PSCR. As such, AVP has preserved recent actual demand profiles in considering the identified need, and will include sensitivities to these at the PADR stage to test the impact of changing consumption patterns.

Maximum demand

To derive transmission connection point load forecasts that align with the regional demand forecasts, AVP has preserved the connection point load profile from the most recent actual annual maximum demand period (17:30 17/01/2023) while scaling overall Victorian regional demand to match the 2023 ESOO maximum demand forecasts (Central, probability of exceedance (POE) 10, summer), and also ensuring any individual connection point load does not exceed its 2022 *Transmission Connection Planning Report* (TCPR)[9] forecast during this process. The power factor at each transmission connection point from the most recent actual annual maximum demand period was also preserved during this scaling.

By way of example, Figure 6 shows the Deer Park connection point maximum demand forecast from the 2022 TCPR, as well as the actual maximum demand observed in FY 2022.

Figure 6 Deer Park Terminal Station 66 kV POE10 summer maximum demand (MVA) forecast, plus the actual maximum demand in 2022



The 2023 ESOO POE10, POE50, and POE90 maximum demand forecasts will be considered and have weightings apportioned during the detailed benefits analysis reserved for the PADR stage.

Minimum demand

AVP has preserved the connection point load profile from the most recent actual annual minimum demand period (13:00 18/12/2022) in scaling overall Victorian regional demand to match the 2023 ESOO minimum demand forecasts (Central, POE90, summer).

[9] Jemena, CitiPower, Powercor, AusNet, United Energy; 2022 TCPR, at https://jemena.com.au/documents/electricity/2022-tcpr.aspx.

As highlighted in Section 2.3.3, minimum operational demand is expected to continue occurring during the day, driven notably by distributed PV exports. With this, it has been assumed that:

- Changes in underlying connection point demand[10] (for both active and reactive power demand) for future annual minimum demand periods will remain relatively fixed.
- Distributed PV will contribute active power output only.

From these assumptions, AVP has assumed that only the active power (megawatts (MW)) component of load will decrease in future annual minimum demand periods, and has therefore preserved the reactive (megavolt amperes reactive (MVAr)) component of loads in Victoria from the most recent actual annual minimum demand period in scaling Victorian regional demand to the 2023 ESOO minimum demand forecasts.

The 2023 ESOO POE90, POE50, and POE10 minimum demand forecasts will be considered and appropriately weighted during the detailed benefits analysis to be undertaken at the PADR stage.

2.3.5 Forecast of generation expansion, withdrawals, and dispatch pattern

In identifying the identified need, all committed generation project developments and withdrawals[11] in Victoria listed in the Generation Information Page[12] at 3 October 2023 were considered. This includes 580 MW / 724 MWh of existing and 200 MW / 400 MWh of committed, but not yet commissioned, BESS capacity and an associated increase in available reactive capacity of grid-scale storage in or near metropolitan Melbourne of approximately ±230 MVAr from existing BESSs and ±79 MVAr from a committed BESS expected online from late-2024.

In addition to the committed projects, this PSCR also considered MW supply availability from future REZ expansion in Victoria in accordance with the 2022 *Integrated System Plan* (ISP) *Step Change* scenario, to help meet forecast load levels in the power system studies.

Table 6 summarises the dispatch assumptions used for maximum demand and minimum demand studies.

Table 6 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 output [D]	Online with 0 MW output [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.

[10] Underlying demand means all electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including distributed PV.

[11] AVP has assumed a reconfigured network in the Latrobe Valley region following Yallourn Power Station's expected retirement in mid-2028. This reconfigured network switching arrangement will be further described in AVP's 2023 VAPR to be published end of October 2023. Changes in this assumption may have a significant impact on the size and locations of required future reactive support, particularly for generating reactive support during maximum demand periods.

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

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.

2.3.6 Forecast of transmission development

AVP has considered all committed, anticipated, and actionable ISP projects impacting the Victorian region from AEMO's 2023 NEM Transmission Augmentation Information page[13].

2.3.7 Reactive power support from inverter-based resources

Large-scale inverter-based resources

AVP assumed reactive support availability from existing and committed large-scale renewable generation in line with respective performance standards and dispatch levels noted in Section 2.3.5. This reactive support consistent with respective performance standards and dispatch levels has been assumed as available where generation has been assumed online as per Table 6, or unavailable where generation has been assumed offline as per Table 6. Reactive support from future, uncommitted, generation and storage projects was not considered, as these connections are not yet guaranteed. However, sensitivities exploring the impact on the identified need from reactive support of future, uncommitted, generation and storage projects will be conducted for the PADR.

Distributed PV installations

In calculating connection point reactive power demand, AVP assumed that distributed PV installations would not provide any reactive power. While recent changes to AS4777 requires distributed PV to provide a volt-var response under certain conditions, historical connections generally do not have this enabled and compliance rates of new connections are relatively low. Compliance rates will continue to be monitored, and assumptions will be updated accordingly in the PADR.

2.3.8 Aging equipment

Services agreements expiring within the next 10 years have been considered in this RIT-T, including reactive power services agreement relating to specific capacitor banks in metropolitan Melbourne that have contract expiration dates in 2027-28, and which have an aggregate generating reactive power capacity of 650 MVAr.

2.3.9 Operational measures

The operational measures outlined in this section are considered as potential short-term mechanisms to manage transmission system voltages; however, without services contracts guaranteeing their availability, AVP considers it is not appropriate to consider them in quantifying the identified need and has therefore omitted their voltage management capability from this PSCR. These measures may need to be relied on to manage voltages in metropolitan Melbourne when required, until such time as investment in reactive support can be economically justified[14], but are most appropriately used in rare emergency situations as last resort.

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

[14] As outlined in NER clause 5.15A.1, the purpose of the *regulatory investment test for transmission* 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.

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 network service providers (NSPs) for voltage support have all been assumed as available in this PSCR 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 500 kV lines. This, and other possible operational measures, are intended to be reserved for more extreme and unexpected operating conditions; for planning purposes, such operational measures are not relied on in determining the additional absorbing reactive power support required to meet future system conditions.

Distributed PV curtailment

Victoria's Emergency Backstop mechanism for solar[15] (to be introduced July 2024) may allow demand as seen by the transmission network to increase (as curtailing distributed PV at times of high output would mean less demand is supplied on the distribution level, and large-scale generation would then be required to meet this demand instead). However, this mechanism would only be used as a last resort to avoid local or state-wide blackouts during rare minimum system load emergencies.

This mechanism would allow more large-scale generation to be dispatched at times of otherwise low demand, resulting in:

- More flow on high-capacity transmission lines and therefore less reactive power being produced on these lines.
- More generation with reactive absorption capability being dispatched and thus online and able to provide this reactive absorption.

The minimum demand forecasts used (see Section 2.3.3) assume that distributed PV is not curtailed, and subsequently the identified need in this PSCR also does not consider it. As already noted, distributed PV curtailment mechanisms are assumed to be reserved for more extreme and unexpected operating conditions.

Keilor over-voltage control scheme

The Keilor 500 kV over-voltage protection scheme – an automatic tripping scheme to manage voltages at Keilor 500 kV – is a backup scheme that is unavailable for normal operating conditions and is intended to be reserved for extreme and unexpected operating conditions. This scheme has therefore not been relied on in determining the identified need of this PSCR.

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.

[15] See https://www.energy.vic.gov.au/renewable-energy/solar-energy/victorias-emergency-backstop-mechanism-for-solar

For maximum demand conditions studied, distribution voltages were observed as reaching low levels as well as transmission voltages, and 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.

3 Credible options to address the need

3.1 Description of credible options

Credible options to meet the identified need are required to maintain voltage stability and have the capability to maintain voltages within existing limits or, in the case of over-voltages only, widen existing operational/ site-specific equipment limits such that operating at voltages up to the NER steady-state limits of 1.1 per unit of normal voltage is possible.

High-level options that may address the identified need in this PSCR are summarised in Table 7.

Table 7 Possible network and non-network credible options to meet the identified need(s)

Need	Type of option	High-level description of option to address the need
Identified Need Pillar One	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	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.
	Non-network option	Further BESS grid connections in the right locations with available reactive support.
Identified Need Pillar Two	Operational / non-network option	Directing on grid-scale storage (such as BESSs) to charge to increase operational demand.
	Network option	Investment to upgrade existing transmission assets, such as the Keilor 500/220 kV transformers, that are currently limiting over-voltages levels below NER limits.
	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.

Possible locations and voltage levels for additional reactive support or load reduction

Identified Need Pillar One (Inability to manage under-voltages within limits)

Power system studies have identified that the most effective locations for additional generating reactive power or load reduction to manage voltage stability in metropolitan Melbourne are Cranbourne 220 kV and 66 kV, Deer Park 220 kV and 66 kV, Rowville 220 kV, and Tyabb 220 kV and 66 kV. More generating reactive power may be required if installed at locations that are less effective at resolving the critical sites' gaps (but may be more practical sites for investment, or may be more effective at addressing both the generating and absorbing reactive shortfalls).

Table 8 shows potential terminal station and voltage level locations where additional generating reactive power support or load reduction may reasonably address Identified Need Pillar One, for any one or more of the sites with gaps. This table also provides an indication of how effective a solution, located at a particular site, is at providing reactive support at the locations where needed.

Based on this, there are a large number of combined permutations that may meet this identified need.

Table 8 Possible solution sites to address largest forecast generating reactive gap size in next 10 years

Solution site (and % effectiveness at resolving gap site) [A]	Sites with gaps [B]		
	Deer Park 220 kV	Tyabb 220 kV	Rowville 220 kV
Brunswick 66 kV	2%	32%	99%
Brunswick 220 kV	2%	28%	83%
Cranbourne 66 kV	1%	79%	133%
Cranbourne 220 kV	1%	70%	109%
Deer Park 66 kV	122%	12%	46%
Deer Park 220 kV	100%	10%	32%
Rowville 220 kV	1%	36%	100%
Templestowe 66 kV	2%	27%	84%
Templestowe 220 kV	2%	25%	76%
Thomastown 220 kV	2%	25%	77%
Tyabb 66 kV	1%	104%	123%
Tyabb 220 kV	1%	100%	113%

A. % effectiveness has been calculated based on a single study snapshot, and may change depending on different system conditions including power flows and voltage profiles. Credible solutions will be tested against a suite of snapshots in the PADR stage to ensure robustness.
B. A % effectiveness of greater than 100% for any solution site indicates that addressing the gap here will be more effective than addressing it at the identified transmission level critical site.

Identified Need Pillar Two (Inability to manage over-voltages within limits)

Power system studies have identified that the most effective locations for additional absorbing reactive power to manage high voltages in metropolitan Melbourne are Keilor 500 kV, Sydenham 500 kV, South Morang 500 kV and Deer Park 66 kV. The total additional absorbing reactive power requirement may be more if installed at other locations that are less effective at resolving the identified transmission level critical sites' gaps. However, alternate sites could be more practical for investment or could prove more effective at addressing both the generating and absorbing reactive shortfalls.

Table 9 shows these and other potential terminal station and voltage level locations where additional absorbing reactive power support may reasonably address Identified Need Pillar 2.

Table 9 Possible solution sites to address largest absorbing reactive gap size in next 10 years

Solution site (and % effectiveness at resolving gap site) [A]	Sites with gaps – Keilor 500 kV
Brooklyn 220 kV	59%
Deer Park 66 kV	80%
Deer Park 220 kV	56%
Hazelwood 500 kV	72%
Keilor 220 kV	60%
Keilor 500 kV	100%
South Morang 500 kV	81%
Sydenham 500 kV	86%

A. % effectiveness has been calculated based on a single study snapshot, and may change depending on different system conditions including power flows and voltage profiles. Credible solutions will be tested against a suite of snapshots in the PADR stage to ensure robustness.

3.2 Network options to address the identified need

3.2.1 Augmenting existing assets to allow wider operational limits

As noted in Table 4, the KTS 500/220 kV transformers have a continuous voltage operating limit of 525 kV, which equates to 1.05 per unit of nominal voltage. Replacing these transformers to increase their continuous voltage capability may be a credible option to alleviate the over-voltage issues identified at Keilor 500 kV.

AVP is currently engaging with AusNet on its plans for retirement of their Keilor No.4 750 MVA 500/220 kV transformer, and its planned replacement with a 1000 MVA transformer in 2028, and will consider this option further in the PADR following sufficient joint planning with AusNet.

3.2.2 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, 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.

Standard capacitor/reactor sizes (MVAr)

A given reactive power shortfall can be met using 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 will need to be carefully selected to achieve the most cost-effective outcome to meet the identified need.

In this PSCR, the following are considered as the standard capacities for capacitors and reactors for the purpose of developing cost estimates for the network options:

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

The following are considered as standard 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 standard capacities have been selected to largely align with existing or retired reactive plant in the DSN, given certainty on their technical feasibility. Non-standard capacities may be assessed in the PADR if proven beneficial.

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 will therefore be assumed for capacitor or reactor options assessed in the PADR.

3.2.2.1 Reactive compensation portfolios and estimates

Possible combinations of network options for additional reactive support (at a high level) to meet the identified needs include:

- Capacitors (+) and reactors (-) only.
- Capacitors (+) and a single dynamic reactive plant (±).
- Capacitors (+) and two dynamic reactive plant (±).

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 PSCR, AVP has, for illustrative purposes, developed options using the transmission level locations most effective at addressing each need. These illustrative portfolios of options do not necessarily translate to being the most economically efficient combination that maximises benefit for consumers, which will be identified at the PADR stage.

Table 10 gives a preliminary indication of the MVAr investment required on an annual basis for the next five years (considering this illustrative portfolio option of locations) to keep transmission voltages within existing limits for both high and low voltage conditions, with an additional projection for 10 years from today.

Table 10 Possible mix of MVAr investment to meet the identified need, for a select combination of locations

	Need location	Technology type	Indicative MVAr support required [A, B]					
			2023-24	2024-25	2025-26	2026-27	2027-28 [C]	2032-33
Combination 1	Deer Park 220 kV	Capacitor	+100	+100	+100	+150	+150	+200
	Tyabb 220 kV	Capacitor	-	-	-	-	-	+150
	Keilor 500 kV	Reactor	-	-150	-300	-500	-350	-750
Combination 2	Deer Park 220 kV	Dynamic reactive plant	±100	±100	±100	±150	±150	±200
	Tyabb 220 kV	Capacitor	-	-	-	-	-	+150
	Keilor 500 kV	Reactor	-	-100	-250	-400	-250	-650
Combination 3	Deer Park 220 kV	Dynamic reactive plant	±100	±100	±100	±100	±150	±200
	Tyabb 220 kV	Capacitor	-	-	-	-	-	+100
	Keilor 500 kV	Dynamic reactive plant	-	±100	±250	±400	±250	±650

A. Optimal timing for investment will be determined through the RIT-T.
B. Values shown in Table 10 represent the total equivalent MVAr support required for each year and are not cumulative.
C. In 2027-28, when Yallourn retires, the minimum synchronous generating combination of four Loy Yang units and one Newport unit is assumed, which improves transmission voltages and reduces the observed gap, even after accounting for retirement of the existing capacitors in that year. If this latter combination of synchronous generation is assumed for years 2024-25, 2025-26, and 2026-27, then the observed gap for the respective year would be less than as shown.

Indicative capital, operating and maintenance costs

The cost estimates provided in Table 11 are based on the standard capacities of reactive power plant and standard connection arrangements described in Section 3.2.2. These are based on indicative class 5B (+/- 50%) prices for reactive power plant and associated connection equipment as given in Appendix A1, which have been developed with reference to the 2023 Transmission Cost Database[16] (TCD) and assume an in-service date of 2027-28. Costs presented are in real 2023 dollars, escalated by consumer price index (CPI) from the TCD real 2021 dollars.

Table 11 Cost estimates

Option	Stage	Description	Total generating MVAr	Total absorbing MVAr	Estimated capital cost ($M)
1	1 (by 2027-28)	1x 150 MVAr shunt capacitor at Deer Park 220 kV 1x 200 MVAr and 1x 150 MVAr shunt reactors at Keilor 500 kV	150	350	44
2	1 (by 2027-28)	1x ±150 MVAr dynamic reactive plant (costed as an SVC) at Deer Park 220 kV 1x 150 MVAr and 1x100 MVAr shunt reactors at Keilor 500kV	150	400	73
3	1 (by 2027-28)	1x ±150 MVAr dynamic reactive plant (costed as an SVC) at Deer Park 220 kV 1x ±150 MVAr and 1x ±100 MVAr dynamic reactive plant (costed as SVCs) at Keilor 500kV	400	400	135

[16] AEMO, 2023 Transmission Expansion Options Report Consultation, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

Operating and maintenance costs are in addition to the capital costs shown in Table 11 and are estimated as 1% of the capital costs. Both capital and operating and maintenance costs will be reviewed and refined during the PADR stage.

Lead times for credible options

The anticipated lead time is 18-24 months for procuring (from contract order to completion at factory door) capacitors and reactors, and 24-36 months for procuring dynamic reactive plant such as SVCs. The actual time required will depend on many factors, such as the location of the manufacturer, whether they are made to order or off-the-shelf products, and the location of the installations.

Table 12 presents indicative timeframes for when a service to meet the identified need might be able to be delivered. These indicative time frames are based on recent industry engagement and delivered projects. Based on these time frames, it is unlikely that a network solution would be able to be delivered to provide additional reactive support for metro Melbourne voltage management before 2027-28. Non-network options may be able to be delivered earlier.

Table 12 Indicative construction timelines and potential commissioning dates (task complete by dates)

Task description	Non-network	Static reactive plant	Dynamic reactive plant
Regulatory investment process	Q2-2024 to Q3-2024	Q2-2024 to Q3-2024	Q2-2024 to Q3-2024
Contract negotiation	Q4-2024	Q4-2024	Q4-2024
Design and long lead procurement	N/A	Q2-2025 to Q4-2025	Q4-2025 to Q4-2026
Construction	N/A	Q2-2026 to Q4-2026	Q4-2026 to Q2-2027
Commissioning	As early as Q1-2025	Q4-2026 to Q2-2027	Q2-2027 to Q4-2027

Other considerations for investigation in the PADR

AVP will further investigate as part of the PADR:

- Any practicality issues, such as site-specific requirements at the relevant location. Different location combinations (able to be derived using information from Table 8 and Table 9), along with combinations of network and non-network solutions, will be further considered as part of this assessment to determine the combination that maximises net market benefit for consumers.
- The impact on system performance of switching large MVAr capacity capacitors or reactors, and the use of smaller MVAr capacity devices or dynamic reactive plant to mitigate the impact, taking into account any real-time operational issues AEMO (as the national operator) has experienced in switching the existing large capacity capacitors or reactors.
- The impact that investment potentially delivered through AVP's ongoing system strength RIT-T[17] may have on the need being addressed by this RIT-T, noting that credible options being considered in the system strength RIT-T may also be capable of providing reactive support while providing their system strength service.
- The potential impact that currently uncommitted connection applications for generation and storage in the metropolitan Melbourne area may have on the need being addressed by this RIT-T.

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

The actual capacities, locations, estimated costs, and optimal timing of the options may be fine-tuned in the PADR, based on further investigations by AVP.

3.3 Non-network options

3.3.1 Description of credible non-network options

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

- Demand response and decentralised storage.
- Additional reactive power support from grid-connected generators and BESSs.
- Distributed PV reactive power support.

Demand response and decentralised storage

The demand level can be decreased during high demand periods or increased during low demand periods by encouraging and promoting demand response, load shifting, coordinated charging of decentralised storage, and contracted charging of grid-scale storage.

It is conceptually possible to alter the demand during high or low demand periods, when a voltage violation is expected to occur, by utilising flexible loads such as hot water and pool pumps, in addition to emerging flexible loads such as electric vehicles (EVs) and distributed storage.

An effective load shift at times of high or low demand is an alternative to the provision of additional generating or absorbing reactive power in addressing the identified need.

AVP is seeking information from potential providers that may have sufficient capability to decrease or increase load, such as big pump loads or battery discharging/charging at appropriate connection points, during periods of high or low demand. See Section 3.3.2 for details of the technical characteristics required of a non-network solution and Section 3.3.3 for other non-network proponent information AVP is seeking.

Additional reactive support from grid-connected generators and BESSs

All grid-connected generators have a requirement to supply and absorb reactive power in accordance with agreed performance standards, as set out in their connection agreements. Any generators or BESSs with a supplying or absorbing reactive power capability higher than the requirement stipulated in the agreed performance standards could provide the spare supplying or absorbing reactive power capability to meet or partially meet the identified needs, and delay or remove the need for investment in network options.

AVP is seeking information from generators, BESSs, and other parties with additional supplying or absorbing reactive power capabilities, load shifting capabilities, or similar means for meeting the identified need. See Section 3.3.2 for details of the information AVP is seeking.

Distributed PV reactive power support

Based on recent changes to AS 4777, it is expected that distributed PV can provide a volt-var response to provide both generating and absorbing reactive power when required. The identified need could be met by aggregating and dispatching the reactive power from these inverters. The dispatch of the aggregated reactive power support from distributed PV inverters has a similar effect to decreasing reactive power loads to alleviate low voltages in the transmission network during high demand periods, or increasing reactive power loads to absorb excess reactive supply in the system during low demand periods.

Distributed PV reactive power support would be more suitable to meeting the low demand, absorbing reactive power need, rather than the high demand generating reactive power need, given that this issue usually manifests at times of high distributed PV output and thus high distributed PV reactive power support availability. High demand periods often occur in the evening when distributed PV might not be as available.

AVP is not aware of any practical means of aggregating and dispatching sufficient generating or absorbing reactive power support from distributed PV installations during periods of extreme demand levels at present, and is seeking information from potential providers of this type of non-network service. See Section 3.3.2 for details of the technical characteristics required of a non-network solution and Section 3.3.3 for other non-network proponent information AVP is seeking.

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

Identified Need Pillar One – Inability to manage under-voltages to within limits

Low voltages occur during high demand periods and commonly result from reactive demand outweighing reactive supply. This need can be interpreted as an equivalent shortfall of reactive supply (that is, a lack of generating reactive capability) needed to meet the power system's reactive demand.

Without the provision of additional generating reactive support services, AVP has observed that the voltage level at numerous locations in metropolitan Melbourne may be at risk of falling below operational limits in the next decade.

Table 13 presents the annual forecast reactive power shortfall[18] under 1-in-10 year maximum demand conditions over the next five years and with an additional projection for 10 years from today, based on the maximum demand forecasts and assumptions detailed in Section 2.3. This reactive shortfall quantity gives an indication of the additional reactive support needed at each site to maintain voltages to within system normal operating limits following a credible contingency; that is, to maintain post-contingent voltages within 0.95 per unit of the normal voltage level at that connection point.

Table 13 Indicative generating reactive power gap sizes forecast in next 10 years

Critical site	Reactive power requirement (MVAr) to meet the identified need					
	2023-24	2024-25	2025-26	2026-27	2027-28	2032-33
Deer Park 220 kV	20	90	100	110	120	200
Tyabb 220 kV	Nil	Nil	Nil	Nil	Nil	130
Rowville 220 kV	Nil	Nil	Nil	Nil	Nil	30

Table 13 also shows that there is a small 20 MVAr generating reactive shortfall forecast at Deer Park 220 kV in 2023-24 rising to 90 MVAr in the subsequent year. This is predominately driven by the forecast increase in local Deer Park 1-in-10 year maximum demand beyond the terminal station's maximum supportable demand (see Figure 6). AVP will continue engaging with Powercor, the local DNSP, to better understand the likely timing and

[18] Calculated as the amount of reactive support required at the respective site to bring that site's voltage within 0.005 per unit of its lower voltage limit, for system normal and post-contingency conditions. This amount was calculated for each critical site individually, and therefore the total investment to resolve all issues may be less than the sum of each critical site's gap.

location of forecast demand changes and any planned transmission connection asset augmentations that may allow this level of demand to be supplied from Deer Park Terminal Station.

Reducing load to within the maximum supportable demand is an alternative means of managing voltage levels to within limits. Table 14 presents the forecast reduction in demand (MW), relative to 1-in-10 year forecast maximum demand levels, required to manage over-voltages to within limits.

Table 14 Indicative demand reduction required to meet the identified need forecast in next 10 years

Critical site	Load reduction requirement (MW) to meet identified need					
	2023-24	2024-25	2025-26	2026-27	2027-28	2032-33
Deer Park 220 kV	20	70	80	90	100	150
Tyabb 220 kV	Nil	Nil	Nil	Nil	Nil	120
Rowville 220 kV	Nil	Nil	Nil	Nil	Nil	<1

Identified Need Pillar Two – Inability to manage over-voltages to within limits:

High voltages occur during low demand periods and commonly result from reactive supply outweighing reactive demand. Based on this, this need can also be interpreted as an equivalent shortfall of reactive demand (that is, absorbing reactive support) needed to absorb the excess reactive supply in the power system. Without the provision of additional absorbing reactive support services, AVP has observed that the voltage level at Keilor 500kV may be at risk of being lifted above operational limits.

Table 15 shows what the reactive shortfall[19] annually is forecast to be at this site over the next five years and with an additional projection for 10 years from today, based on minimum demand studies using assumptions as detailed in Section 2.3. This reactive shortfall quantity gives an indication of the required reactive support at this site to ensure its respective voltage remains within operational limits for a secure operating state.

Table 15 Indicative absorbing reactive power gap sizes forecast in next 10 years

Critical site	Reactive power requirement (MVAr) to meet identified need					
	2023-24	2024-25	2025-26	2026-27	2027-28	2032-33
Keilor 500 kV	Nil	150	270	460	310	750

Table 15 also shows that a reactive shortfall is expected to first emerge for this site as early as 2024-25. This assumes a minimum synchronous generating combination of three Loy Yang units and two Yallourn units. In 2027-28, when Yallourn retires, the minimum synchronous generating combination of four Loy Yang units and one Newport unit has been assumed, which improves transmission voltages and reduces the observed gap. This is due to the proximity of Newport to the voltage management issues, and the reactive power capability it provides locally when operating. If this latter combination is assumed for years 2024-25, 2025-26, and 2026-27, then the observed gap for the respective year would be less than shown in Table 15. Operational measures such as those noted in Section 2.3.9 will need to be relied on until such time as investment can be delivered and is net beneficial for consumers.

[19] Calculated as the amount of reactive support required at the respective site to bring that site's voltage within 0.005 per unit of its upper voltage limit, for system normal and post-contingency conditions. This amount was calculated for each critical site individually, and therefore the total investment to resolve all issues may be less than the sum of each critical site's gap.

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

The above is not an exhaustive list of non-network services. AVP welcomes proponents of non-network options to make submissions on any non-market ancillary services (NMAS) they can provide to address either, or both, pillars of the identified need outlined in this PSCR.

Submissions should include details on:

- Organisational information.
- Relevant experience.
- Details of the service.
- Cost of service, separating capital and operational expenditure.
- Confirmation of timelines in providing the service.

3.3.4 Material inter-network impact

AVP considered whether the credible options are expected to have a material inter-regional impact[20]. A 'material inter-network impact' is defined in the NER[21] as "*a material impact on another Transmission Network Service Provider's network, which may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network*".

In its Inter-Network Test Guidelines[22], AEMO suggests a screening test to indicate whether or not a transmission augmentation has a material inter-network impact. Applying this screening test, no material inter-network impact can be assumed if the transmission augmentation satisfies any of the following:

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

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

[20] As per clause 5.16.4(b)(6)(ii) of the NER.

[21] See Chapter 10 of the NER.

[22] AEMO, Inter-Network Test Guidelines, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/inter-network-test-guidelines/internetwork-test-guidelines.pdf?la=en.

4 Materiality of market benefits

AVP notes the NER requirement that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the RIT-T proponent can demonstrate that:

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

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

- **Wholesale electricity market benefits:** the credible options considered in this PSCR 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 generator competition, generator dispatch outcomes, and subsequently the wholesale electricity market. AVP considers the following classes of market benefit to be associated with the wholesale electricity market, and subsequently considers that they are not material for this RIT-T:
  - Changes in fuel consumption arising through different patterns of generation dispatch.
  - Changes in price-responsive voluntary load curtailment, since there is no material impact on wholesale electricity market prices.
  - Changes in costs for parties, other than for AVP, since there will be no material impact on the timing of other investment.
  - Changes in ancillary services costs.
  - Competition benefits.
- **Differences in the timing of expenditure**, as the credible options are unlikely to impact the timing of unrelated expenditure.
- **Changes in network losses,** as the credible options considered in this PSCR are not expected to materially impact transmission losses.

5 Next steps

AVP welcomes written submissions on this PSCR, particularly in relation to non-network options, to be provided via written submission to **AVP_RIT-T@aemo.com.au**, with subject title ‘Metropolitan Melbourne Voltage Management PSCR, by 5pm on 31 January 2024.

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

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

A1. Building block costs of reactive plant and associated equipment

Table 16 Unit costs of reactive plant and associated equipment used in estimating option costs

Voltage level	Rating (MVAr)	Equipment [A]	Cost ($M) [B]
500 kV	200 MVAr	Shunt reactor	$16.5
		Static VAr Compensator	$44.0
	150 MVAr	Shunt reactor	$15.3
		Static VAr Compensator	$43.3
	100 MVAr	Shunt reactor	$14.5
		Static VAr Compensator	$41.7
220 kV	200 MVAr	Shunt reactor	$10.4
		Shunt capacitor	$7.8
		Static VAr Compensator	$36.4
	150 MVAr	Shunt reactor	$9.8
		Shunt capacitor	$7.5
		Static VAr Compensator	$35.7
	100 MVAr	Shunt reactor	$9.2
		Shunt capacitor	$6.8
		Static VAr Compensator	$34.2
66 kV	50 MVAr	Shunt reactor	$5.6
		Shunt capacitor	$4.3

Note: Transmission costs have been developed based the AEMO Transmission Cost Database (TCD) and 66 kV costs are based on recent industry experience alongside the TCD. AEMO's Transmission Cost Database (TCD) is available at https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.
A. Inclusive of connection costs
B. In real June 2023 Australian dollar values