AEMO
AUSTRALIAN ENERGY MARKET OPERATOR
Victorian Planning

Victorian Annual Planning Report

October 2023

Electricity transmission planning for Victoria

Important notice

Purpose

The purpose of this publication is to provide information relating to electricity supply, demand, network capability, and development for Victoria's electricity transmission declared shared network.

AEMO Victorian Planning (AVP) publishes the Victorian Annual Planning Report (VAPR) in accordance with clause 5.12 of the National Electricity Rules. This publication is generally based on information available to AVP as at June 2023, although AVP has incorporated more recent information where practical.

Disclaimer

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

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

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution of Victorian network service providers in providing data and information used in this publication.

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Executive summary

Victoria needs to continue urgently progressing key transmission projects if the state is to avoid risks to the reliable supply of electricity over the next 10 years. The planned investments help reduce overall costs to consumers by unlocking lower-cost generation supplies, enhancing competition, increasing power system resilience, and improving the efficiency of resource sharing between neighbouring regions.

The transformation of Victoria's power system – driven by consumer choices, energy market participant choices, and state and federal government policy – is not stopping. **The main changes shaping the state's transmission needs in the next decade are**:

- **The geographic location of supply continues to diversify.** While historically generation largely came from the east of the state, from large brown coal generators in the Latrobe Valley, in the future supply will come from both renewable resources and interconnectors in the east and west of the state.
- **Growth continues in two-way energy flowing from consumers and their own energy resources** – like rooftop photovoltaic (PV) systems, batteries and electric vehicles (EVs) – into the grid, as well as the traditional flow from the grid to consumers.
- **The latest forecasts indicate that consumption of electricity will increase**, as homes and businesses switch from other fuel sources like gas to electricity, while **minimum demand from the grid continues to decline, requiring management of a range of challenges** to the secure operation of the power system.

To meet Victoria's future needs, action is already being taken through AEMO Victorian Planning's (AVP's) Transmission Development Plan for Victoria. This plan is updated annually as part of the *Victorian Annual Planning Report* (VAPR), aligns with the *Integrated System Plan* (ISP), and is designed to deliver security and reliability objectives in the context of Victorian Government policy and regulatory settings.

AVP is progressing a suite of projects across the state to address constraints in Victoria's Declared Shared Network (DSN). These include the Western Renewables Link (WRL), Victoria – New South Wales Interconnector West (VNI West) and major augmentations under the Renewable Energy Zone (REZ) Development Plan (RDP) Stage 1, all advancing to detailed design and delivery stages, and Regulatory Investment Tests for Transmission (RIT-Ts) proceeding to improve reactive power availability and system strength in Victoria.

This VAPR highlights that action is also required to address emerging limitations in both east and west metropolitan Melbourne, to ensure supply reliability for the Victorian energy consumers. The emerging limitations identified in this VAPR are:

- **Eastern Metropolitan Melbourne** – overloads of the Rowville A1 500/220 kilovolts (kV) transformer during system normal conditions, and of the Thomastown – Ringwood 220 kV line for loss of the Rowville A1 transformer.
- **Western Metropolitan Melbourne** – overloading of the Moorabool – Geelong 220 kV lines for a trip of the parallel line.

AVP plans to undertake holistic assessments of the DSN in the east and west of Melbourne to ensure the network is utilised efficiently under future system conditions and to identify the options for augmentation, including non-network options. The significant changes expected over the next decade, including the retirement of the Yallourn Power Station, will make flow paths more complex and challenging to manage using the existing network configuration.

In the next year, detailed assessments, including confirmation of the identified network limitations and assessment of benefits through detailed market modelling, will be completed and appropriate RIT-Ts progressed.

This VAPR aims to manage Victoria's risks in the context of rapid policy, operational and network development changes

The context for Victoria's network planning in the next decade includes:

- **The Victorian Government has introduced or progressed a range of policies and initiatives** since the 2022 VAPR, aimed at facilitating efficient development of Victorian renewable energy zones (REZs) and major transmission infrastructure, and of renewable energy generation and storage to meet increased targets.
- **Investment interest remains strong**. Victoria's total installed generation capacity (at July 2023) is 19.6 gigawatts (GW) – 8.1 GW of large-scale renewable generation (wind, solar, storage and hydro), 7.4 GW of large-scale conventional thermal generation (coal and gas), and approximately 4.1 GW of consumer energy resources (CER), mostly distributed PV. About 420 megawatts (MW) of new large-scale renewable projects have connected in Victoria in the past year, another 1.0 GW are committed to connect, and over 33 GW of large-scale renewable generation and 5 GW of battery storage projects have submitted connection enquiries.
- Continuing growth of renewable energy generation and storage systems in diverse geographic areas, including remote locations where renewable resources are abundant, is creating additional supply hubs that are **making power flow bi-directional and altering flow patterns** in the DSN. Future proposed development of offshore wind in Gippsland and Portland is expected to continue to diversify the location of supply sources.
- The system must be operated carefully to manage the increasing penetration of inverter-based resources (IBR), using **new sources of system security services** – such as reactive power capability, inertia and system strength – traditionally supplied by thermal generation.
- As household and business consumers continue to install their own distributed PV generation and storage systems, Victoria's **levels of minimum grid demand continue to decline**, requiring additional market-based solutions (like coordinated storage and electric vehicle (EV) charging, scheduled loads such as pumping load, and demand response) to support system security at these times.
- The energy sector continues to mature and adapt as it **seeks social license and engages with a range of communities in planning and developing the transmission required** to support Victoria's energy transition, recognising the need to improve its approach to avoid harm and disruption.
- The **future network must operate without generators whose retirements have been announced** – this includes Victoria's Yallourn (2028), Loy Yang A (2035) and Loy Yang B (2047), and the state is also impacted by the retirement of Torrens Island B in South Australia (by June 2026).
- The 2023 *Inputs, Assumptions and Scenarios Report* (IASR) forecast **higher consumption of electricity in Victoria and higher maximum demand** than in previous reports, driven mainly by updated assumptions about industry sectors, business and households switching from other fuel sources (such as gas) to electricity.

In 2022-23, the DSN experienced operating challenges but was kept secure

The Victorian DSN remained secure in 2022-23, despite record low minimum demand and unprecedented levels of IBR generation. Notable network performance observations are:

- The annual peak Victorian operational demand in 2022-23 was 8,988 MW on 17 January 2023 (compared to 8,599 MW in 2021-22). This remains low compared to the historical summer maximum demand of 10,576 MW in 2008-09, before the substantial uptake of distributed PV.
- There was no directed load shedding or emergency reserves dispatched through Reliability and Emergency Reserve Trader (RERT) in 2022-23. Once, on 16 February 2023, an actual Lack of Reserve level 1 (LOR1) was declared in Victoria, but was subsequently cancelled due to increased generator availability and net import to Victoria.
- Victoria recorded its all-time lowest minimum operational demand of 2,195 MW on 18 December 2022. This was 138 MW lower than the previous record set last year, and the fourth consecutive year that the record has been broken, with distributed PV meeting 55% of Victoria's underlying demand.
- The newly installed reactors at Keilor and Moorabool Terminal Stations have significantly reduced the need for operational intervention to manage high voltage occurrences, despite the record minimum demand and increasing number of low demand days.

Progress has been made on projects to address constraints identified in earlier VAPRs

AVP's annual planning review for Victoria assesses current and forecast supply, demand and operational challenges, to identify potential investments that can help reduce overall costs to Victorian consumers by unlocking lower-cost generation supplies, increasing power system resilience, and improving the efficiency of resource sharing between Victoria and its neighbouring regions.

Since the 2022 VAPR, the VNI Minor (also named VNI East Upgrade) project has been completed (it was listed as committed in the 2022 VAPR). This upgraded the existing VNI to install and energise a second 500/330 kV transformer at South Morang Terminal Station, re-tension the 330 kV South Morang – Dederang lines, and install power flow controllers on the Upper Tumut to Canberra and Upper Tumut to Yass 330 kV lines.

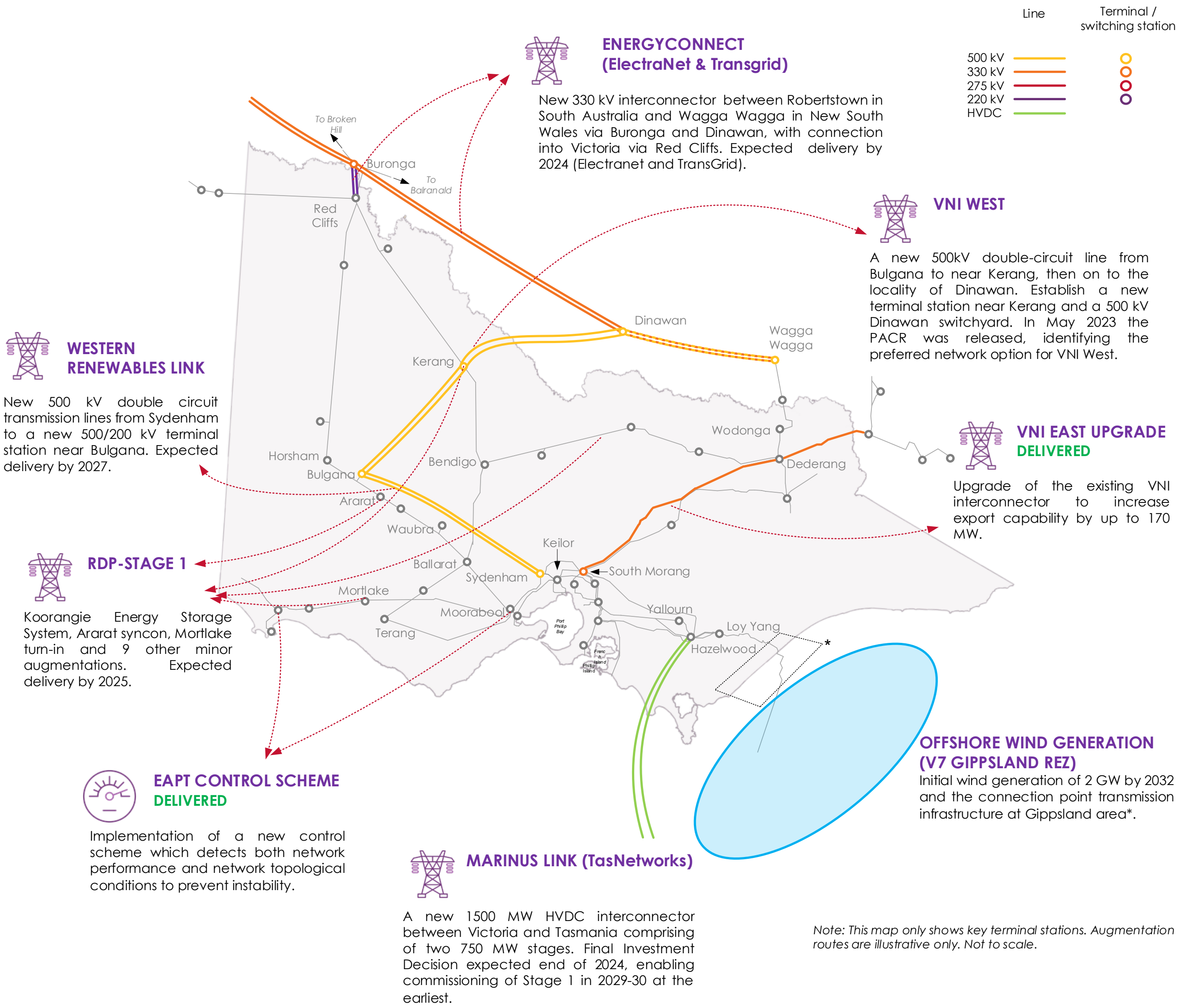
Other critically important transmission projects continue to progress:

- Western Renewables Link (WRL) – the scope of this project, which will unlock renewable energy resources, reduce network congestion, and improve utilisation of existing assets in western parts of Victoria, has been updated as an outcome of the VNI West options analysis to build a 500 kV connection from Sydenham to Bulgana, removing the need for an additional terminal station north of Ballarat. WRL is now expected to be completed mid-2027.
- VNI West – the final RIT-T report on a proposed new high capacity 500 kV double circuit overhead transmission line to carry energy from the Murray River and Western Victoria REZs and increase the state's export and import capacity, has identified a preferred option and a draft corridor report has been published. A new AEMO company, Transmission Company Victoria (TCV), has been established to undertake early works including community, landholder and Traditional Owner consultations and ongoing investigations into the corridor and ultimate route. VNI West is expected to be first energised in 2028 and fully operational by the end of 2029.

- RDP Stage 1 projects – AVP has undertaken procurement activities, directed by the Victorian Government, for three projects to strengthen the system, nine projects for minor network augmentations, and turn-in of the Haunted Gully to Tarrone 500 kV line at Mortlake. These projects, which will support the connection of more low-cost renewable generation in regional Victoria, are progressing towards detailed design and delivery stages. The majority of the minor augmentations are expected to be completed by October 2025.

Progress is also continuing on EnergyConnect, linking South Australia and New South Wales (with a connection to north-west Victoria), with Stage 1 commissioning expected in mid-2024, and early works on Marinus Link which would enable commissioning of the first cable between Victoria and Tasmania in 2029-30. **Figure 1** presents the projects that are being delivered, or have been delivered in the past 12 months, as part of the Transmission Development Plan for Victoria.

Figure 1 Existing projects that are part of the Transmission Development Plan for Victoria



Two RIT-Ts have begun that are addressing system strength and reactive power (Metropolitan Melbourne Voltage Management RIT-T) in the Victorian DSN, to address emerging limitations identified in the 2022 VAPR and system strength requirements identified through AEMO's 2022 *System Strength Report*[1].

The 2023 Annual Planning Review highlights the need to holistically address emerging limitations in eastern and western metropolitan Melbourne

AVP's Transmission Development Plan for Victoria is designed to meet security and reliability objectives in the most efficient way over the coming decade, and to address emerging limitations that are forecast to impact the DSN in that 10-year period. AVP constantly identifies and monitors limitations, and undertakes an assessment each year in the Annual Planning Review that is part of the VAPR. The aim is to identify and communicate about projects that are likely to deliver net positive economic benefits under the current regulatory framework, or where corrective action is required to keep the DSN reliable and secure.

Significant changes to supply, demand and the network have already impacted how power flows around the DSN, and these changes are forecast to continue, requiring timely network development action. After Victoria's brown coal generators retire, there are expected to be times when supply will come from many different areas of Victoria and be imported via interconnectors, and the existing network will no longer be adequate to get electricity to consumers. While work is underway to increase inter-network and REZ capacity, this will not address the issues forecast to arise closer to load centres, particularly metropolitan Melbourne, due to increase in demand and changing flow direction.

The updated Transmission Development Plan for Victoria therefore focuses on reinforcing both the eastern and western metropolitan areas, so the network can serve the growing Melbourne load from geographically diverse supplies which are being developed.

The most urgent new identified needs in the updated Transmission Development Plan for Victoria are these emerging limitations:

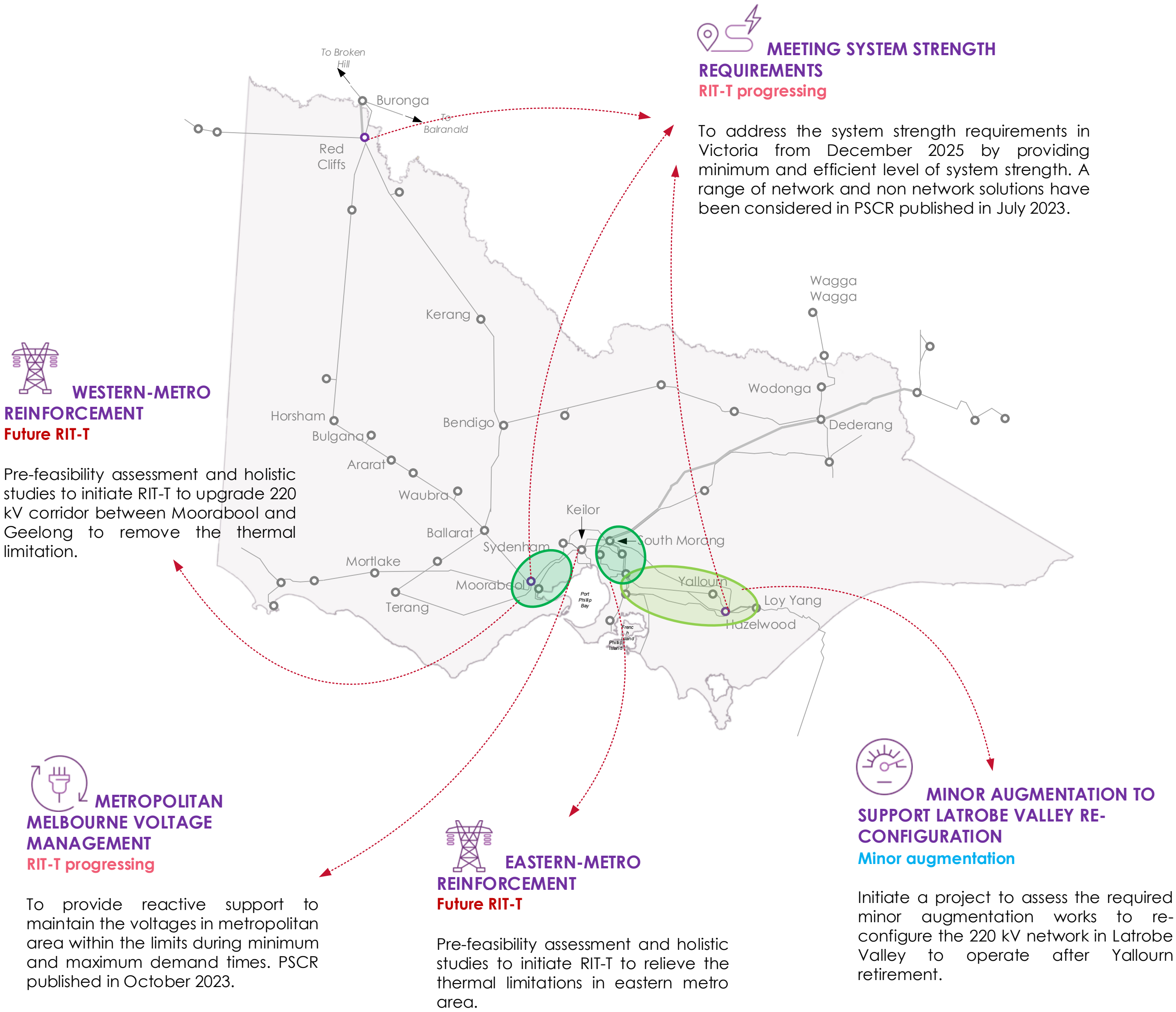
- **Western Metropolitan Melbourne, overloading of the Moorabool – Geelong 220 kV lines for trip of the parallel line (due primarily to periods of high generation in South West Victoria and Western Victoria as well as high demand in Greater Melbourne).**
- **Eastern Metropolitan Melbourne, overloading of the Rowville A1 500/220 kV transformer during system normal (due primarily to high demand in Greater Melbourne).**
- **Eastern Metropolitan Melbourne, overloading of Thomastown – Ringwood 220 kV line for loss of the Rowville A1 transformer (due primarily to high demand in Greater Melbourne and retirement of Yallourn Power Station).**

AVP intends to commence holistic assessments of the network configuration in both the east and west of metropolitan Melbourne and determine whether additional network upgrades or non-network investments are needed, so the network is utilised efficiently under future system conditions. Depending on outcomes of these assessments, RIT-Ts for augmentations to support demand growth in metropolitan Melbourne may commence in the next 12 months.

The updates to the Transmission Development Plan for Victoria are summarised in **Figure 2**, including the system strength and Metropolitan Melbourne Voltage Management RIT-Ts that have already begun.

[1] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-system-strength-report.pdf?la=en.

Figure 2 Updates to Transmission Development Plan for Victoria



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1 Introduction

This section outlines the purpose and a summary of the content of the 2023 *Victorian Annual Planning Report* (VAPR).

1.1 Purpose and scope of the 2023 VAPR

The 2023 VAPR assesses the adequacy of the existing Victorian Declared Shared Network (DSN) to meet network performance requirements, and identifies DSN limitations over the next 10 years.

Through the VAPR process, AEMO Victorian Planning (AVP) updates its Transmission Development Plan for Victoria, adapting the plan to the changing nature of demand and considering changes in the geography and characteristics of supply mix in the context of Victorian Government policy and regulatory settings.

It builds on the national plan developed through AEMO's *Integrated System Plan* (ISP). The VAPR studies provide local insights relating to Victoria's network security, reliability of supply, demand forecast, network capability, system performance, and emerging network needs, with a particular focus on developments most likely to deliver positive net economic benefits to energy consumers or where corrective action is required to keep the DSN reliable and secure.

The Annual Planning Review undertaken by AVP and presented in this report has considered the policy initiatives and directives of the Victorian Government (see Section 2.1.3) in identifying network limitations for the next 10 years and proposing solutions to those limitations in the Transmission Development Plan for Victoria.

1.2 Roles and responsibilities

1.2.1 AEMO Victorian Planning (AVP)

The National Electricity Rules (NER) require all transmission network Jurisdictional Planning Bodies to publish an Annual Planning Report (APR) by 31 October each year following an Annual Planning Review. AVP, as the Jurisdictional planner for the Victorian DSN, is required to publish the VAPR.

The VAPR assesses the adequacy of the Victorian DSN to meet the network performance requirements set out in schedule 5.1 of the NER over the next 10 years, triggers the need for investment where required, and provides information and insights to stakeholders as specified in NER 5.12.

To identify the adequacy of the DSN over the 10-year planning horizon, the VAPR takes into account:

- The most recent demand forecasts from AEMO's 2023 *Inputs Assumptions and Scenarios Report* (IASR)[2].
- Generation plant and retirement information (using the July 2023 update on AEMO's Generation Information web page[3]).

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

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

- Committed, anticipated and Future ISP projects (from AEMO's Transmission Augmentation Information page[4]) and network/non-network projects initiated by VicGrid.
- Proposed distribution augmentations identified in the 2022 Transmission Connection Planning Report[5] prepared by the Victorian DNSPs.

1.2.2 VicGrid

VicGrid, a division of Victoria's Department of Energy, Environment and Climate Action (DEECA), coordinates the overarching planning and development of Victorian renewable energy zones (REZs).

The Victorian Government will be introducing new legislation in early 2024 to establish the Victorian Transmission Investment Framework (VTIF), as a new framework for how major electricity transmission infrastructure and REZs will be planned and developed in Victoria[6].

Through the VTIF, the Victorian Government plans to introduce changes to the way electricity transmission infrastructure is planned and delivered in Victoria. The VTIF reforms are designed to attract investment by giving greater certainty to renewable energy investors and to build community support for the energy transition. The Victorian Government has stated[7] that it intends to include new Strategic Land Use Assessments, more opportunities for input from communities, Traditional Owners and landholders and new approaches to sharing benefits more equitably.

Under the new framework, VicGrid is expected to develop a 25-year strategy plan for Victorian transmission and REZ development, called the Victorian Transmission Plan (VTP). The first VTP is expected to be published in 2025. To ensure consistency between Victorian and national planning processes, the VTP review process will align with the publication of the ISP and VAPR, and allow updated information to be reflected.

1.3 Structure of the 2023 VAPR

In the 2023 VAPR:

- **Section 2** outlines the overall context for this review of the Victorian DSN, including policy and regulatory, supply and demand changes, and operational and network developments.
- **Section 3** reviews the performance of the DSN throughout 2022-23, including operational challenges, notable power system incidents, and performance of the network under a range of operating conditions.
- **Section 4** provides an update on network investment activities and investigations that have progressed since the 2022 VAPR.
- **Section 5** details the Annual Planning Review, explores potential new or changed limitations that may trigger the need for detailed investment options analysis and consultation (Regulatory Investment Test for Transmission, RIT-T), and presents the Transmission Development Plan for Victoria.

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

[5] See https://jemena.com.au/documents/electricity/2022-tcpr.aspx.

[6] See https://engage.vic.gov.au/victorian-transmission-investment-framework.

[7] See at https://www.land.vic.gov.au/government-land/government-land-advice/policy-and-guidelines.

- **Section 6** provides available fault level forecasts, required to be provided by AVP as Victoria's System Strength Service Provider.
- **Section 7** presents updated information on joint planning with network service providers (NSPs). It covers AusNet Services' Asset Renewal Plan, outlining expected network asset retirements, deratings, and renewals within the VAPR's 10-year timeframe, including AVP's assessment of the future network needs associated with these assets.
- **Section 8** explores the implications for transmission network planning of a very different energy future.
- **Appendix A1** summarises recent trends in Victorian exports over interconnectors with other states.
- **Appendix A2** provides detailed snapshots supporting the discussion of the performance of the Victorian DSN in 2022-23.
- **Appendix A3** includes a summary of the approach to network limitation review.
- **Appendix A4** provides details of DSN limitations, as an outcome of this review.

AEMO welcomes feedback on the 2023 VAPR, via https://aemo.com.au/contact-us.

1.4 Supporting material

Table 1 lists a suite of electronic resources to support the content in this report. Unless otherwise indicated, these resources are published alongside the VAPR on AEMO's website[8].

Table 1 2023 VAPR supporting resources

Resource	Description
Historical DSN rating and loading workbook	Ratings and loadings for the 2022-23 maximum demand and high export periods presented in Section 3 and Appendix A2.
AusNet Services 2023 asset renewal plan	AusNet Services' transmission asset renewal process and provides a list of its planned asset renewal projects, including asset retirements and de-ratings for the next 10-year period, including changes since last year and the various options considered.
Asset related datasets	• Transmission connection point data for each transmission terminal station where primary station assets are associated with an actual or forecast emerging network limitation. • Transmission line segment data for each transmission line between terminal stations that are associated with a historical or emerging line capacity limitation. • Aggregated generation connection data for each connection application or new (completed over the last 12 months) connection agreement at terminal stations or areas where the connections could affect existing or emerging network limitations.
Constraint reports	AEMO uses constraint equations to operate the DSN securely within power system limitations. The constraint equations are implemented in the National Electricity Market Dispatch Engine (NEMDE), which dispatches generation to ensure operation within the bounds of power system limitations. AEMO's annual and monthly constraint reports detail the historical performance of these constraint equations. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams.
DNSP demand forecasts	The transmission connection point planning report prepared by the Victorian DNSPs provides information on historical and forecast demand, including DNSPs' terminal station demand forecast

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

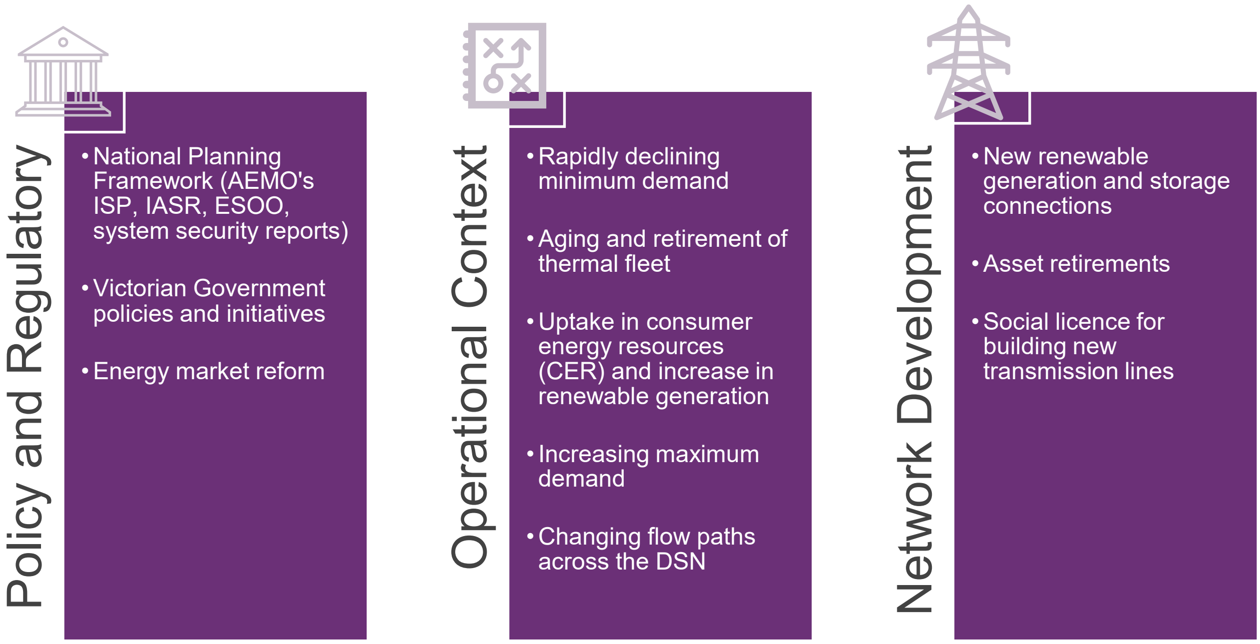
Resource	Description
	(TSDF) and the causes of differences between these and AEMO's connection point forecasts for Victoria. At https://jemena.com.au/documents/electricity/2022-tcpr.aspx.
Power System Frequency Risk Review (GPSRR)	An integrated, periodic review of major power system frequency risks associated with non-credible contingency events in the NEM. At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review#:~:text=The%20Power%20 System%20Frequency%20Risk,National%20Electricity%20Market%20(NEM).
System Security reports	AEMO's system strength, inertia and network support and control ancillary services (NSCAS) assessments, collectively known as the *System Security Reports* under National Electricity Rules (NER) 5.20. At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.
Inputs, Assumptions and Scenarios Report (IASR)	At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.
VNI West Project Assessment Conclusion Report (PACR)	At https://aemo.com.au/en/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission.
Victorian System Strength Requirement RIT-T Project Specification Consultation Report (PSCR)	Victorian system strength requirement regulatory investment test for transmission (RIT-T), at https://aemo.com.au/en/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission.
Metropolitan Melbourne Voltage Management RIT-T Project Specification Consultation Report (PSCR)	The first report in the Metropolitan Melbourne Voltage Management RIT-T process, at https://aemo.com.au/initiatives/major-programs/metropolitan-melbourne-voltage-management-regulatory-investment-test-for-transmission.

2 Context of the 2023 VAPR

This section outlines the regulatory, policy, operational, network, and connections context in which the 2023 VAPR has been prepared, and the implications of this context for network planning in Victoria.

The context for network development is changing rapidly, both nationally and regionally, with multiple moving parts across regulation, policy, operations, network connections and demand-supply conditions as the energy sector changes rapidly. **Figure 3** summarises the key context areas of the 2023 VAPR, discussed in sections 2.1, 2.2 and 2.3.

Figure 3 Key context areas of 2023 VAPR



2.1 Policy and regulatory context

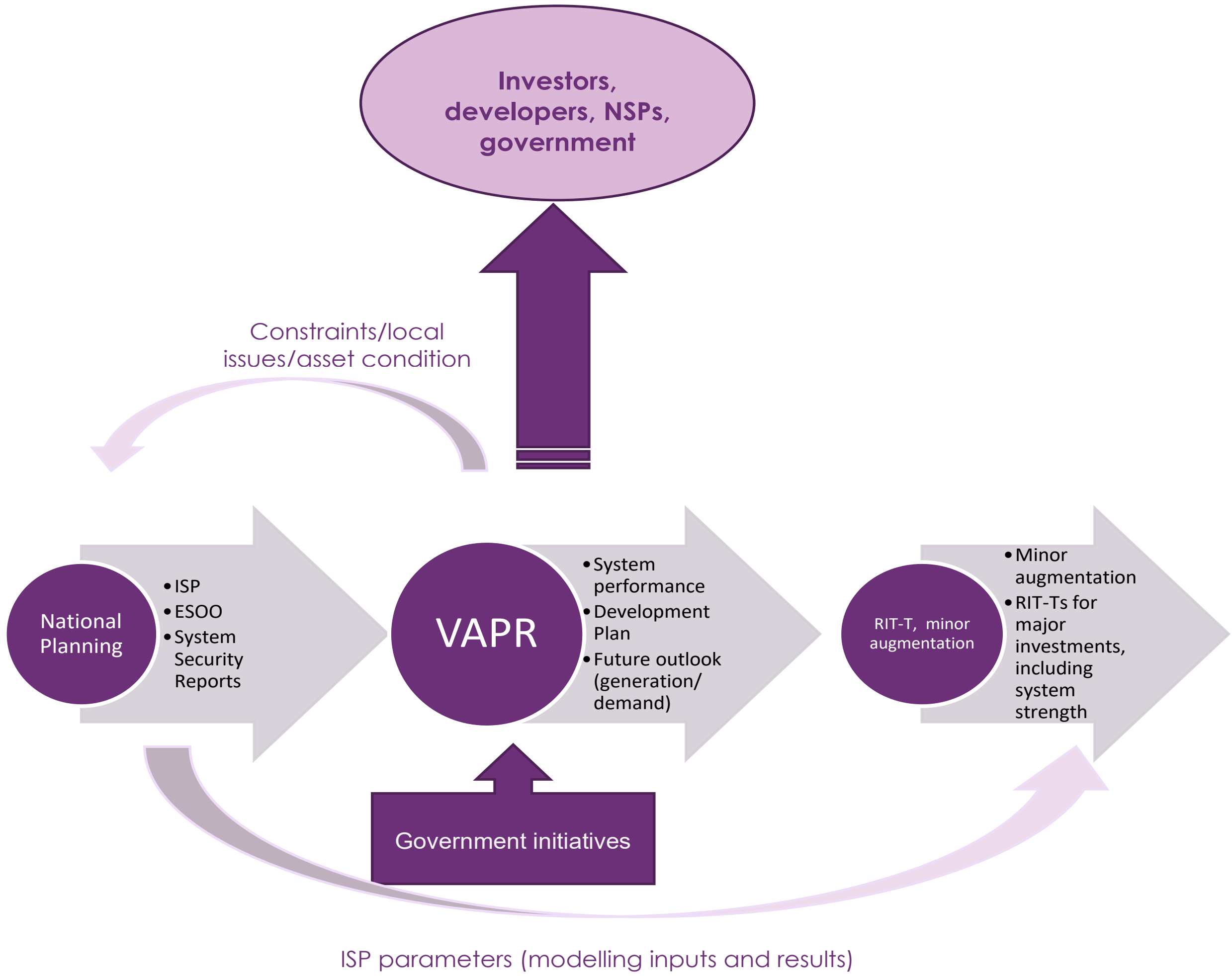
Policy and regulatory changes can have a significant impact on network projects, including the identification of newly emerging limitations, and the changing nature of planning in the DSN.

2.1.1 The national planning framework

The national transmission planning framework streamlines the regulatory framework by allowing outputs from the ISP and other publications related to the national transmission planning framework – such as system security reports (system strength, inertia and network support and control ancillary services (NSCAS) reports) – to be incorporated into transmission network service provider (TNSP) investment decisions. This relationship is illustrated in **Figure 4**. Under this approach:

- Comprehensive system-wide modelling in the ISP identifies network needs, and a set of options that efficiently meets those needs, as part of an optimised development path for the National Electricity Market (NEM).
- The VAPR leverages these nationally optimised plans from the ISP, and overlays them with more detail about local congestion issues and regional performance characteristics.
- The VAPR studies are then used to inform interested parties in Victoria, trigger regulatory investment processes, or flow back into the ISP to improve and refine subsequent publications.
- Together, the ISP and the VAPR initiate the regulatory investment test for transmission (RIT-T) process, which aims to validate the potential benefits of projects that can meet an identified need, explore lower-cost variations, and ensure any subsequent investment decision is robust and transparent.
- The System Security Reports assess the minimum and efficient levels of system strength required in each NEM region over the coming decade, and the inertia requirements and any shortfalls, and any gaps in non-market ancillary services (NMAS) over a five-year horizon, which may require further network or non-network development to address.

Figure 4 Relationship between national planning, government initiatives, VAPR and investments

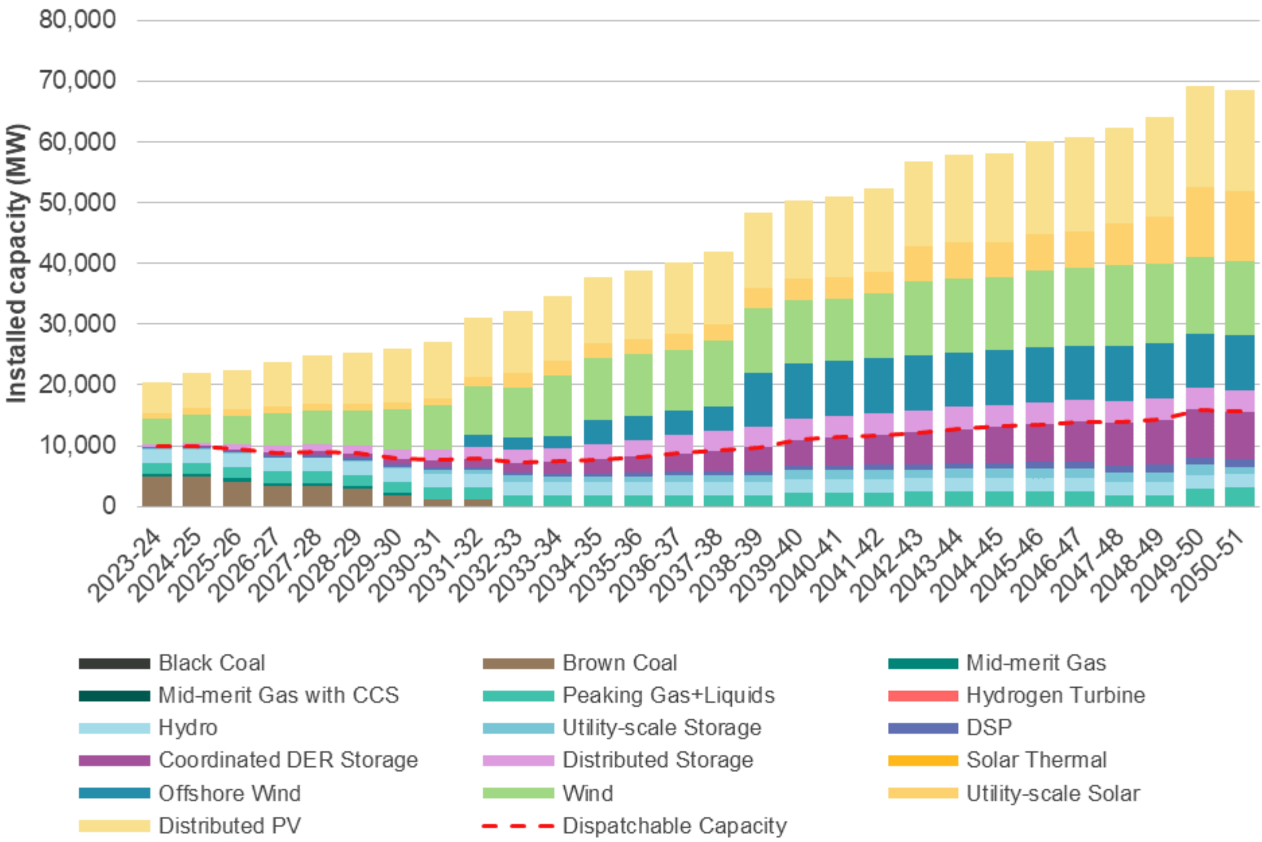


2022 *Integrated System Plan* projected rapid generation and storage change in its most likely *Step Change* scenario

For the latest ISP, published in 2022, extensive stakeholder consultation determined that the *Step Change* scenario should be considered the most likely scenario. *Step Change* represents a future with a rapid, consumer-led transformation of the energy sector and a coordinated economy-wide approach to efficiently lowering emissions. The *Step Change* scenario being developed for the 2024 ISP, as described in AEMO's 2023 IASR[9], refines the earlier *Step Change* scenario and keeps rapid emission reduction as a key assumption.

Based on latest advice from asset owners, Victoria's coal-fired Yallourn Power Station is expected to retire in 2028, followed by Loy Yang A in 2035 and Loy Yang B in 2047[10]. Over that same period, electricity consumption is projected to increase as other sectors electrify to reduce their own carbon emissions. To replace retiring coal generation and supply the increasing requirement for electricity while still meeting emission reduction targets, the 2022 ISP optimal development path projected a large number of additional renewable generation and storage projects in the region (see **Figure 5**)[11].

Figure 5 Forecast Victorian installed capacity, 2022 ISP *Step Change* scenario (offshore wind sensitivity), 2023-24 to 2050-51



9 See https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

10 See AEMO, Generation Information webpage, Generating Unit Expected Closure Year, July 2023 update, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

11 See ISP 2022 Development Opportunities, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a2-isp-development-opportunities.pdf?la=en.

The Victorian Government is supporting development of the generation and storage that is needed for the transition, through its Renewable Energy Zones Development Plan (RDP) Stage 1 projects, offshore wind targets, and other initiatives highlighted in Section 2.1.3.

System security reports identified emerging need for network support and control ancillary services (NSCAS), system strength and inertia services

As thermal power plants age, and market conditions change driven by higher proportions of renewable generation, these thermal power plants are moving to more flexible operation in Victoria and across the NEM. AEMO's studies, in its capacity as national planner, have shown that the reduced unit commitment of thermal plants, and growing risk they would not be available, have increased the need for additional services to maintain the DSN in a secure, safe and reliable state, including:

- System strength – AEMO's 2022 *System Strength Report*[12] identified shortfalls in system strength around Metropolitan Melbourne and the Latrobe Valley due to the projected decline in the number of synchronous units online in the Latrobe Valley. This projected decline is driven by the retirement of Yallourn Power Station, increasing penetration of CER, and corresponding decrease in minimum operational demand.
- System strength issues are expected to exacerbate under system normal and may require direction of units due to declining minimum demand and expected retirements of coal generation. Managing power system security during periods of high renewable generation and planned and unplanned outages, especially in north-west Victoria, is causing congestion and raising new power system stability challenges.
- AEMO published the first *System Strength Report* in December 2022 under the evolved framework that defines the system strength requirements for Victoria (and other jurisdictions) over a 10-year outlook period[13]. As the System Strength Service Provider for Victoria, AVP is investigating potential solutions to provide the minimum and efficient levels of system strength for the DSN. See Section 5.2.1 for further details, including the recently commenced RIT-T[14].
- Inertia – AEMO's 2022 *Inertia Report* projected inertia in Victoria declining below the minimum threshold level and the secure operating level throughout its five-year outlook period. It identified shortfalls against the secure operating level ranging from 2,421 megawatt seconds (MWs) to 2,482 MWs, from 1 July 2026. AVP continues to work with other jurisdictional planning bodies, and AEMO National Planning, to review this forecast shortfall.
- NSCAS – AEMO's 2022 *NSCAS Report* did not identify any NSCAS gaps in Victoria for the five-year outlook period.

2.1.2 Regulatory changes and processes

On 21 September 2023, federal and state Energy Ministers agreed to amendments to the national energy laws to incorporate an emissions reduction objective in the National Electricity Objective (NEO). The Australian Energy Regulator (AER) has released and consulted on draft guidance on the amended NEO, and when final guidance is published and relevant rule changes commence, AVP will amend its planning processes and reports as required.

[12] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2022-system-strength-report.pdf?la=en.

[13] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

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

The Australian Energy Market Commission (AEMC) has made the following rule changes since the 2022 VAPR:

- **Efficient management of system strength on the power system**[15] – the AEMC made a final rule determination designed to proactively deliver forecast system strength needs. It has three main elements: supply side (commenced 1 December 2022), coordination, and demand side reforms (both commenced 15 March 2023). See Section 6 for more information on how this rule affects AVP's planning activities for the Victorian DSN. AVP recently commenced the RIT-T for the Victorian system strength requirement.
- **Material changes in network infrastructure project costs**[16] – on 27 October 2022, the AEMC published the final determination and a 'more preferable' final rule on the 'Material change in network infrastructure project costs' rule change.

2.1.3 Victorian Government policies and initiatives

The Victorian Government has made several policy announcements and commitments that are impacting the drivers for, and economics of, investment in the Victorian network. Changes to government policies or new initiatives since the 2022 VAPR are:

- **VTIF**[17] – in July 2023, the Victorian Government published the final design paper introducing VTIF, a new strategic framework to facilitate efficient development of Victorian REZs and major transmission infrastructure. This framework is expected to be legislated in 2024. Under the new framework, VicGrid will develop a 25-year strategy plan for Victorian transmission and REZ development, called the Victorian Transmission Plan (VTP). The first VTP is expected to be published in 2025.
- **REZ Development Plan (RDP) –** as outlined in the RDP Directions Paper[18], AEMO worked with the Victorian Government to develop the RDP Stage 1 to provide short- to medium-term solutions to strengthen the existing network and accelerate REZs. In October 2022, the Victorian Government issued the Third REZ Stage 1 *National Electricity (Victoria) Act 2005* (NEVA) Order directing AEMO to enter into contracts with the declared transmission system operator for the network augmentations identified in REZ Stage 1[19]. See Section 4.1 for further details of the augmentation works covered by RDP Stage 1.
- **Offshore Wind Targets** – the Victorian Offshore Wind Policy Directions Paper identifies the waters off the Victorian coast as "a world-class offshore wind resource, with at least a 13 GW opportunity in initial tranches near Gippsland and Portland"[20]. The Paper outlines Victoria's vision to achieving net-zero greenhouse gas emissions by 2050 with offshore wind, paving the way to host the first offshore wind farms in Australia. The Victorian Government will support the establishment and growth of this emerging industry by committing to a 2032 offshore wind target for Victoria of at least 2 GW, and is aiming for the first power by 2028, following a competitive process. As a long-term commitment to offshore wind, Victoria is also setting targets to reach 4 GW of offshore wind capacity by 2035 and 9 GW by 2040.
- **Offshore Wind Transmission Development and Engagement Roadmap** – VicGrid is coordinating the transmission for offshore wind projects[21], which will also enable nearby onshore projects. Several documents

[15] See https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[16] See https://www.aemc.gov.au/rule-changes/material-change-network-infrastructure-project-costs.

[17] See https://engage.vic.gov.au/download/document/31853.

[18] At https://www.energy.vic.gov.au/__data/assets/pdf_file/0028/580618/Victorian-Renewable-energy-zones-development-plan-directions-paper.pdf.

[19] Victoria Government Gazette No. S547, 14 October 2022, at http://www.gazette.vic.gov.au/gazette/Gazettes2022/GG2022S547.pdf.

[20] See https://www.energy.vic.gov.au/renewable-energy/offshore-wind-energy.

[21] At https://engage.vic.gov.au/project/offshore-wind-transmission-in-gippsland-and-portland/page/development-and-engagement-roadmap.

have been published to inform the project development process[22], including the Offshore Wind Implementation Statement 2[23], a Summary of Transmission Infrastructure that summarises different types of transmission technology and considerations when planning transmission, a Draft Options Assessment Method and an Engagement Summary Report which summarises the community, landholders and stakeholder engagement undertaken to inform the development of offshore wind transmission in Gippsland and Portland. Once the Options Assessment Method is finalised, VicGrid will assess options for transmission corridors for the offshore wind areas and share the preferred option in early 2024.

- **Victorian energy storage targets**[24] – announced in September 2022, these targets aim to connect at least 2.6 GW by 2030 and at least 6.3 GW by 2035 of both short- and long-duration energy storage systems. The inclusion of both short- and long-duration systems will allow energy to be moved around during the day and to be supplied through longer duration imbalances.
- **Victorian Renewable Energy Target Auction #2 (VRET2)**[25] – six projects were announced by the Victorian Government in October 2022 to bring online 623 megawatts (MW) of new renewable energy generation capacity and up to 365 MW/600 megawatt hours (MWh) of new energy storage. VRET2 will help meet Victoria's legislated renewable energy targets of 40% by 2025 and 50% by 2030. Much of the proposed variable renewable energy (VRE) is expected to be built in the Victorian REZs, which seek to coordinate network and renewable investment.
- **Victorian Renewable Energy Target** – the Victorian Government has announced it intends to legislate updated Emissions Reduction Targets of 65% by 2030 and 95% by 2035[26].
- **Victorian Emission Reduction Target**[27] – in May 2023, the Victorian Government confirmed the new emission reduction target for 2035. The new targets to reduce the state's emission are 75-80% by 2035 and net zero emission by 2045.
- **Energy innovation fund**[28] – in addition to the three offshore wind projects that secured funding under Round 1 (completed in March 2022) to support feasibility and pre-construction activities, four other projects secured funding under Round 2 since the 2022 VAPR, including Terang 100 MW/200 MWh grid-forming energy storage and the Yarra Valley Water Hydrogen project.
- **Solar Homes Program**[29] – Solar Victoria released its Notice to Market for 2023-24, introducing new requirements to support stability of the energy grid, while helping meet the growing demand for all-electric homes and businesses, by requiring system installations to comply with dynamic export requirements to meet future energy needs[30].
- **Victoria's Gas Substitution Roadmap**[31] – this aims to empower households and businesses in Victoria to embrace sustainable alternatives to fossil gas. From 1 January 2024, the phase-out of new gas connections

[22] See https://engage.vic.gov.au/offshore-wind-transmission-in-gippsland-and-portland.

[23] At https://www.energy.vic.gov.au/__data/assets/pdf_file/0017/622241/offshore-wind-implementation-statement-2.pdf.

[24] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets#heading-1.

[25] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets/victorian-renewable-energy-target-auction-vret2.

[26] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

[27] See https://www.climatechange.vic.gov.au/climate-action-targets.

[28] See https://www.energy.vic.gov.au/grants/energy-innovation-fund.

[29] See https://www.solar.vic.gov.au/.

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

[31] See https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap.

will apply to new dwellings, apartment buildings and residential subdivisions that require a planning permit. The 2023 IASR for the NEM[32] projects that this will lead to greater electrification so contributes to forecast growth in electricity consumption.

- **Amendment to Marinus Link funding and scope**[33,34] – in September 2023, a new deal was struck with the Federal, Tasmanian and Victorian Governments to prioritise development of Marinus Link's first cable, with negotiations to continue on a second cable, to be considered as part of the financial investment decision.

2.2 Operational context

The energy landscape in Victoria continues to change rapidly, largely driven by the significant growth in renewable energy generation and storage systems in diverse geographic areas, including remote locations where renewable resources are abundant. New large-scale investment being developed in the west of the state is creating additional supply hubs making power flow bi-directional and altering flow patterns in the DSN, while increasing penetration of inverter-based resources (IBR) continues to impact system stability and the operational challenges in the power system.

The combined effect of the growth in CER, large-scale renewable generation developments and retirement of aging thermal power plant is reducing the supply of system security services traditionally supplied by thermal generation – such as reactive power capability, inertia and system strength – for the DSN.

Section 3 has detailed discussions on operational challenges encountered in managing the Victorian DSN over the past year.

2.2.1 Rapidly declining minimum demand

The 2023 IASR forecasts minimum operational demand in Victoria declining rapidly in all scenarios, due to the projected uptake of distributed PV. **Figure 6** shows the projected daily load profile for a minimum demand day for the planning horizon under the Step Change scenario. This forecast suggests a growing need for:

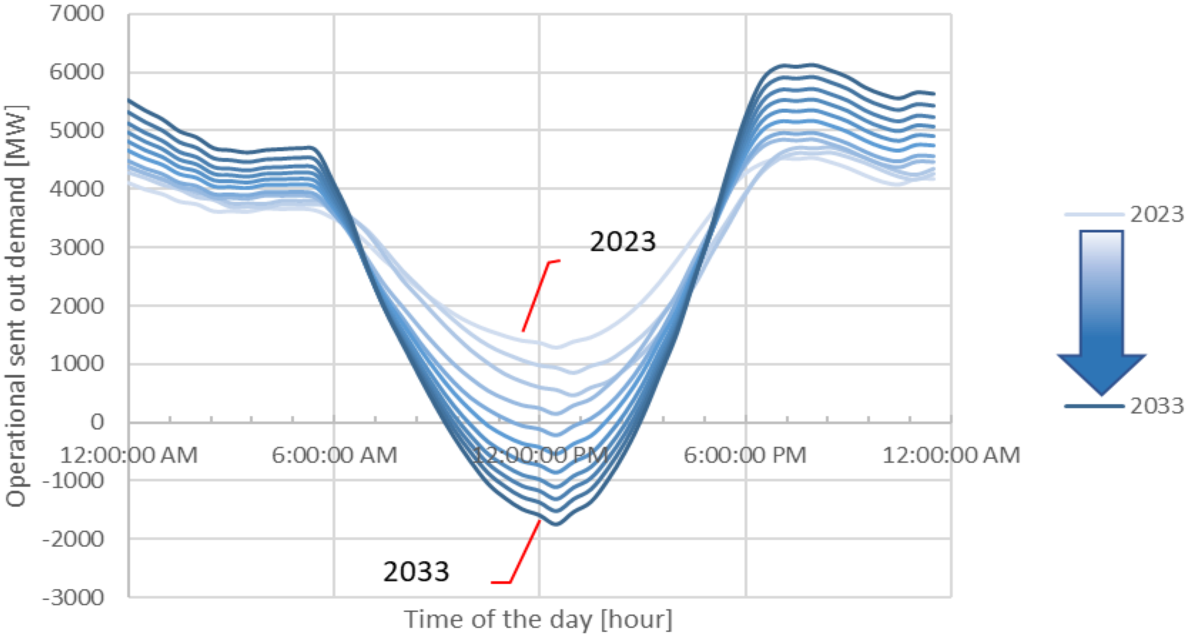
- Victoria to be able to export excessive generation to neighbouring NEM regions, and
- Additional market-based solutions such as coordinated storage and EV charging, scheduled loads such as pumping load, and demand response, to support system security during light demand conditions.

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

[33] See https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-investing-future-tasmanian-energy-marinus-link#:~:text=Marinus%20Link's%20latest%20cost%20estimates,to%20be%20%24106%2D117%20million.

[34] See https://www.marinuslink.com.au/2023/09/marinus-link-advances-under-new-deal/.

Figure 6 Forecast daily load profile on minimum demand day (2023-33)



2.2.2 Aging and retirement of thermal fleet

Since the 2022 VAPR, the following retirement of thermal generation has been announced[35]:

- Torrens Island B (800 MW) – in November 2022, AGL announced that it would close Torrens Island 'B' Power Station (South Australia) by June 2026, and will continue to progress the transformation of the Torrens Island site into a low-carbon industrial Energy Hub.
- Vales Point B (1, 320 MW) – the retirement of Vales Point (New South Wales) has been re-assessed to extend its life, and the closure date has been updated to 2033 (and will be subject to market conditions and related commercial considerations).

In addition to the above recent announcements since the 2022 VAPR, the following generator retirements have been considered in the base cases as planning inputs, as per previously made announcements on generation closure:

- Yallourn (1,450 MW) – as announced in March 2021, will be retired in 2028.
- Loy Yang A (2,210 MW) – as announced in October 2022, will be retired in 2035.
- Loy Yang B (1,160 MW) – as announced in 2019, will be retired in 2047.

While not included in the VAPR base cases, the modelled outcomes from the 2022 ISP *Step Change* scenario highlight that coal generation could be withdrawn even earlier than these expected closure dates.

2.2.3 Increasing maximum demand

Overall electricity demand is projected to increase state-wide as other sectors electrify to reduce their own carbon emissions.

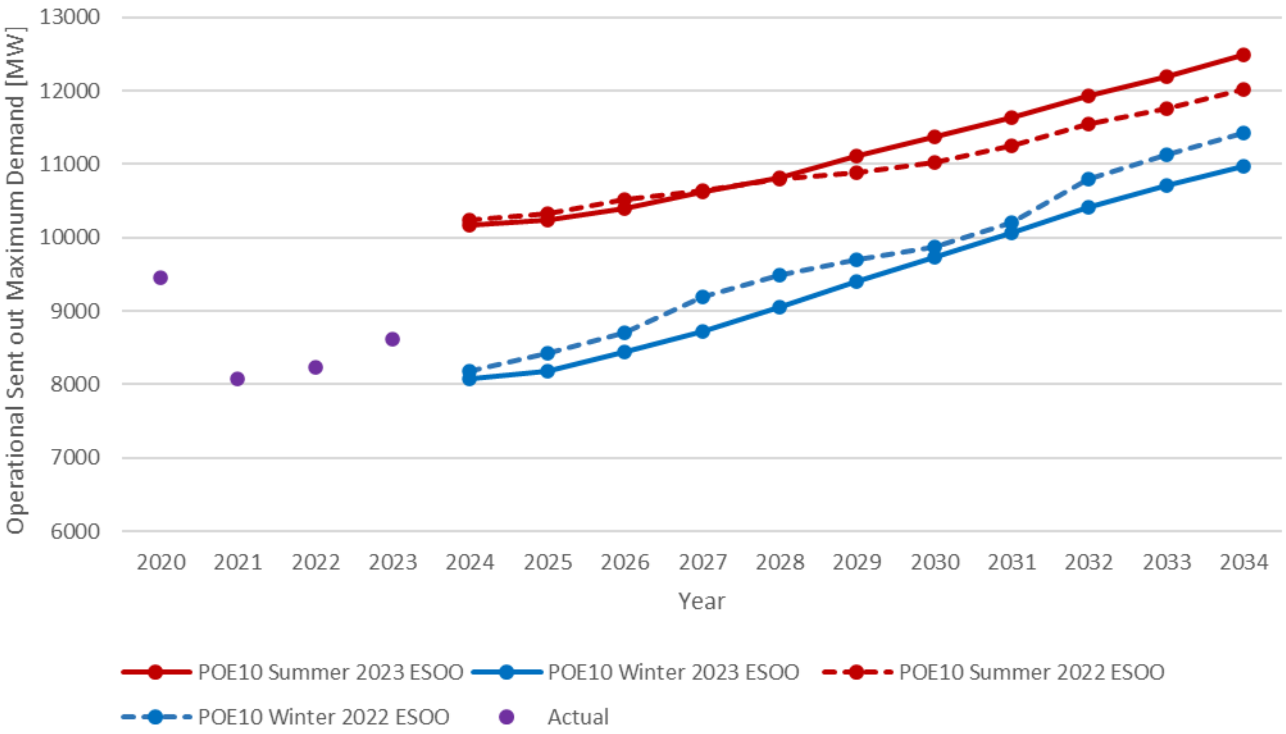
[35] See AEMO, Generation Information webpage, July 2023, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

The 2023 IASR summer maximum operational demand in Victoria, used in the 2023 ESOO, is forecast to be generally higher than the 2022 ESOO, due to higher forecast underlying consumption driven by cooling (air-conditioning) demand and improved assumptions in forecasting methodologies. The 2023 IASR forecast that Victoria will be winter peaking beyond the planning horizon (in year 2045-46).

Figure 7 and **Figure 8** show the 2023 IASR summer and winter operational sent out maximum demand forecasts for 10% probability of exceedance (POE) and 50% POE respectively in the Step Change scenario[36] used in the Annual Planning Review. The actual maximum demand reported in Victoria in the previous years (occurred in summer) is also shown in the same figures.

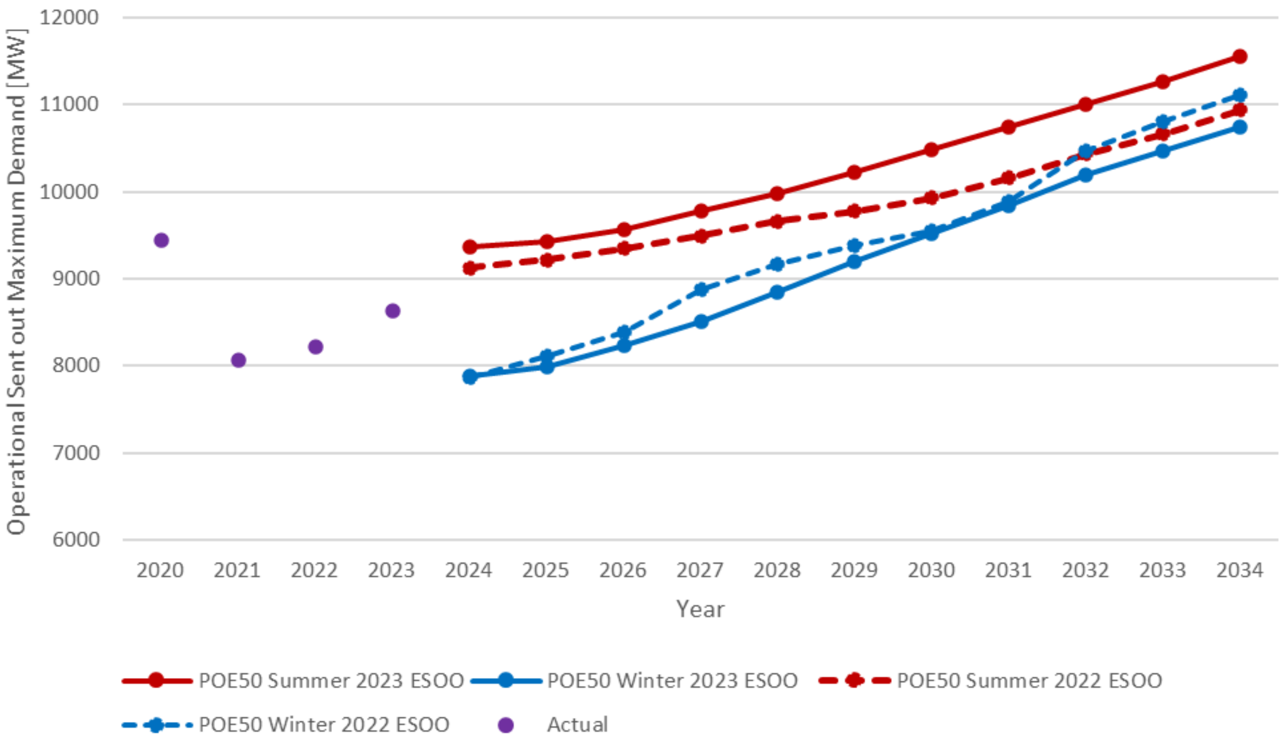
The 2023 IASR forecast that Victoria will continue experiencing maximum demand in summer for the planning horizon for both 10% POE and 50% POE demands – unlike the 2022 ESOO forecast, which anticipated a winter peaking demand from 2031-32 (for 50% POE). Both forecasts indicate similar growth rates for the next 10 years.

Figure 7 Actual and forecast summer and winter maximum demand in 2022 ESOO and 2023 IASR (10% POE, operational sent-out), 2020-34



[36] A 50% POE means the forecast is expected statistically to be met or exceeded one year in two, and is based on average weather conditions; a 10% POE (for maximum demand) or 90% POE (for minimum demand) forecast is based on more extreme conditions that could be expected one year in 10. 'Sent out' forecasts are measured at generators' terminals (so do not include the generators' own electricity use). See 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.

Figure 8 Actual and forecast summer and winter maximum demand in 2022 ESOO and 2023 IASR (50% POE, operational sent-out), 2020-34



2.2.4 Changing flow paths across the DSN

Victoria continues to attract investment in both large-scale renewable generator connections and energy storage systems which is changing the way existing transmission infrastructure is utilised.

As Victoria decarbonises its electricity grid, the geographic location of supply has diversified, with additional solar and wind generation being developed in the west of the state while large brown coal generators in the Latrobe Valley have identified expected closure dates. Solar and wind generation sources, including offshore wind, are also anticipated to develop in the east to take advantage of existing transmission resources. Given the intermittent nature of solar and wind resources, both the east and west generation developments will be required to meet the overall needs of Victorian consumers. While the network to the east is expected to largely accommodate generation developments replacing coal in the next decade, the network to the state's west is being utilised above and beyond its design, which will constrain renewable generators in the short term. Major transmission augmentations such as WRL and VNI West have been identified as the most cost effective way to deliver energy to consumers in the medium to long term.

The 2022 VAPR highlighted the emerging trend of changing power flows with historical average flow in the 500 kV corridor from Latrobe Valley in the state's eastern side declining and average flow from the west and south western corridor in Victoria into the greater Melbourne and Geelong areas increasing[37]. This has resulted in additional generation-driven limitations on the existing network.

This trend of changing flows is expected to continue over the next decade, particularly following the anticipated retirement of Yallourn Power Station in 2028, the uptake in large-scale renewable generation in the west, and planned transmission augmentation in the west and south-west of the state unlocking additional renewable

[37] See Figures 28 and 29 in the 2022 VAPR.

generation and increasing the interconnector capability. Over time, it is anticipated that development of offshore wind generation in Gippsland and MarinusLink interconnection will drive the need for a resilient, flexible network that can accommodate high (and low) levels of supply from either the eastern or western corridors.

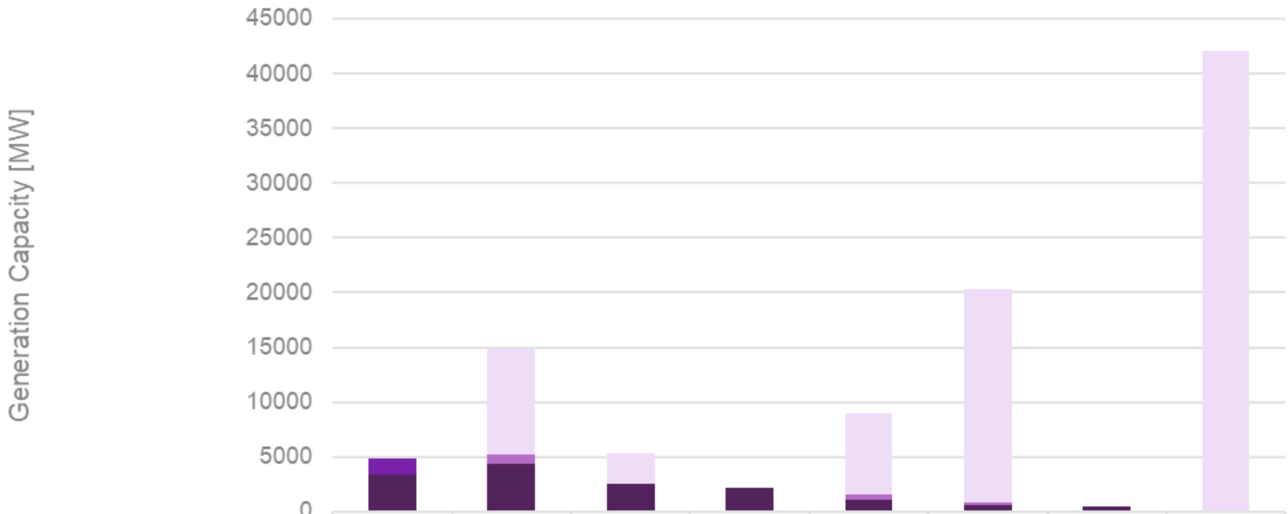
See Section 5 of this document for more details about the identified generation-driven limitations caused by the increasing flow from western and south-western Victoria.

2.3 Network development context

2.3.1 New renewable generation and storage connections

Victoria continues to attract strong interest in new renewable generation and storage projects, with a number of large-scale renewable generator and battery connections projects in the connections pipeline, as shown in **Figure 9**[38].

Figure 9 Existing, committed and proposed large scale generation capacity in Victoria



	Coal	Wind-Onshore	Gas	Hydro	Solar	Battery Storage	Biomass	Wind-Offshore
Proposed projects [MW]		9579	2866		7415	19546		42076
Committed projects [MW]		927			485	200		0
Announced Retirement [by 2033] [MW]	1450							
Existing [less Retirement] [MW]	3385	4314	2475	2183	1029	581	450	0

Note: Committed includes projects that are currently undergoing the commissioning process, 'large-scale generation' means individually greater than 20 MW, and retirements are those that owners/operators have announced will occur in the next decade.

[38] See AEMO, Generation Information webpage, July 2023, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

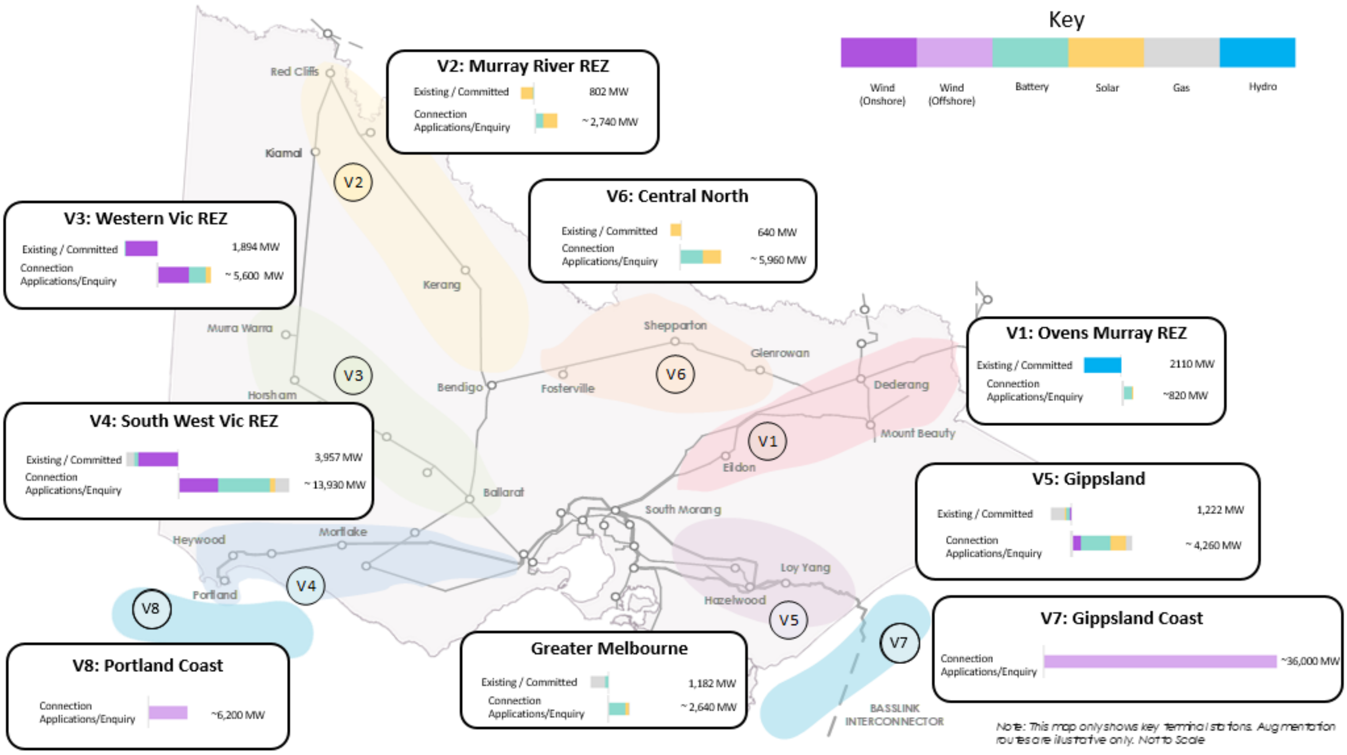
Figure 10 shows that, as well as approximately 4.1 GW[39] of CER, Victoria has increased:

- Total installed generation capacity (large-scale and distributed) to 19.57 GW.
- Installed renewable generation capacity to 12.2 GW (62% of total large-scale and distributed generation), including:
  - 5.9 GW of large-scale wind, solar generation, and battery storage.
  - 2.3 GW of hydro generation.

Since publication of the 2022 VAPR, approximately 420 MW of large-scale renewable projects (individually greater than 20 MW) have connected in the Victorian transmission network, while another 94 MW has been connected as embedded generation into the distribution network. The large-scale renewable projects that completed commissioning in the past year include:

- Mortlake South Wind Farm (157.5 MW) – connected at 220 kV Terang Terminal Station.
- Hazelwood Battery Energy Storage System (BESS) (150 MW) – connected at 220 kV Hazelwood Terminal Station.
- Berrybank Wind Farm Stage 2 (109.2 MW) – connected at 220 kV Berrybank Terminal Station.

Figure 10 Summary of existing generation capacity and connections pipeline in Victoria



[39] See AEMO DER Register and https://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations. Data is taken up to 25 July 2023.

There is a further 1.1 GW of wind generation and battery storage capacity committed[40] to connect in Victoria, including:

- Golden Plains Wind Farm Stage 1 (730 MW) – connecting at 500 kV Cressy Terminal Station.
- Hawkesdale Wind Farm (89.5 MW) – connecting at 132 kV Tarrone Terminal Station.
- Glenrowan Solar Farm (102 MW) – connecting at 220 kV Glenrowan Terminal Station.
- Rangebank BESS (200 MW) – connecting at 220 kV Cranbourne Terminal Station.

The following generators or battery storage capacity met AEMO's generator commitment criteria after July 2023, hence have not been considered in the annual planning review undertaken for the 2023 VAPR:

- Gnarwarre BESS (250 MW) – connecting at new 220 kV Gnarwarre Terminal Station.
- Latrobe Valley BESS (100 MW) – connecting at 66 kV Morwell Terminal Station.

Of the 78.6 GW[41] of proposed wind, solar and storage projects in Victoria, connections enquiries have been submitted for 33 GW of renewable generation and 5 GW of storage.

2.3.2 Social licence for building new transmission lines

AVP acknowledges the significant scale and pace of the transmission build required to meet Victoria's changing energy needs and enable a net-zero future, and the disproportionate impacts felt by regional and rural people and businesses that host new energy infrastructure. Obtaining social legitimacy and credibility for new transmission projects is challenging, and without a social licence to operate, projects face delays, and cost increases.

The energy sector will continue to mature and adapt in terms of its approach to stakeholder expectations, government policy and social justice issues, learning from national and international experiences and using better integrated planning, design and benefit sharing strategies. In particular, there is room to improve the ways in which communities are engaged, their views heard and their feedback about important social, environmental, cultural issues are incorporated in the planning for the new transmission network. This could help reduce the burden, and increase understanding about the benefits, to landowners, host communities, Traditional Owners, Victorian consumers and other interested parties through its transformation in the way Victoria generates and consumes electricity in future continue.

[40] 'Committed' projects have secured land and planning approvals, executed contracts for the supply and construction of major equipment components and for finance, and have either started construction or have set a firm date. For more details on AEMO's commitment criteria, see the Background Information tab on each update at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[41] See AEMO, Generation Information webpage, July 2023 at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

3 Network performance in 2022-23

This section reviews the performance of the Victorian DSN throughout 2022-23, including operational challenges, notable power system incidents, and the performance of the network under a range of operating conditions. While the rapidly changing system makes past performance less dependable than it historically has been as a basis for planning future investments, this review reflects important current challenges and opportunities.

Key network performance observations

The Victorian DSN remained largely secure in 2022-23, despite record low minimum operational demand and unprecedented levels of IBR generation:

- The annual peak Victorian operational demand in 2022-23 was 8,988 MW on 17 January 2023, compared to 8,599 MW in 2021-22. Summer operational maximum demand was higher than in the previous two years, due to increased load in Victoria, but is still lower than recent historical demand levels (for example, 9,852 MW in 2019-20) due to the substantial uptake of distributed PV.
- There was no directed load shedding, and no emergency reserves were dispatched through Reliability and Emergency Reserve Trader (RERT), in 2022-23.
- Victoria recorded its all-time lowest minimum operational demand of 2,195 MW on 18 December 2022, which was 138 MW lower than the previous record set last year. This is the fifth consecutive year that the annual minimum operational demand record occurred during the daytime, and fourth consecutive year that the previous record was broken.
- The newly installed reactors at Keilor and Moorabool Terminal Stations have significantly reduced the need for operational intervention to manage high voltage occurrences despite the record minimum demand and increasing number of low demand days.
- Several terminal stations that have historically behaved as net loads increasingly behaved as net generation sources, due to the increases in distribution-connected generation. As in 2021-22, 15 locations experienced reverse flows in 2022-23.

3.1 How AVP assesses network performance

In evaluating the adequacy of the Victorian DSN, AVP considered the following key performance indicators:

- **Notable power system incidents** – the frequency of reviewable incidents[42] or other significant incidents which resulted in system security violation or loss of customer load or generation (Section 3.2).

[42] For the definition of "reviewable operating incident", see NER 4.8.15. AEMO's published operating incident reports are at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

- **Supply-demand adequacy** – the extent to which the operation of the network facilitated or hindered the ability of the power system to meet customer demand (Section 3.3).
- **Operational challenges** – how network operation was impacted by the changing technical characteristics and geography of supply, particularly where such changes increased operational complexity (Section 3.4).
- **Impact of constraints** – the severity of network constraints (Section 3.5).
- **Interconnector capability and performance**– the extent to which the operational and design limits of interconnectors restricted the import and export of generation (Section 3.6 and Appendix A1).
- **Behaviour of the DSN at time of high network stress** – a range of case studies examining the performance of the network under extreme operating conditions (Section 3.7 and Appendix A2).

In this section, unless otherwise stated:

- **Generation** is defined as all scheduled, semi-scheduled, and non-scheduled generation greater than 30 MW, and does not include distributed PV systems.
- **Operational demand and consumption** are 'as generated', meaning they include generator auxiliary loads.
- **Distributed PV** refers to PV systems up to 100 kilowatts (kW) capacity.

3.2 Notable power system incidents

Table 2 summarises notable power system incidents in Victoria in 2022-23, and this section highlights emerging issues in the Victorian DSN which may, in future, develop into investment opportunities. This section does not consider events which occurred primarily within the distribution network.

Table 2 Summary of notable power system incidents in Victoria in 2022-23

Date	Incident	Consequence
25 July 2022	Buronga 220 kV isolator failure and trip of multiple transmission elements[A]	• Trip of multiple transmission lines in south-west New South Wales. • Trip of Murraylink interconnector. • Trip of Red Cliff – Buronga (0X1). • Trip of 210 MW wind generation. • 40 MW of load in south-west New South Wales was lost.
11 December 2022	Trip of Kerang-Wemen-Red Cliffs 220 kV line and Kiamal synchronous condenser transformer	• 55 MW of generation and 27 MW of loads were disconnected.

A. This event originated outside of Victoria but has been included due to the effect on the DSN.

25 July 2022 – Buronga 220 kV isolator failure and trip of multiple transmission elements

At 01:15 on 25 July 2022[43], an isolator at Buronga substation failed, resulting in a 220 kilovolts (kV) phase to ground fault on blue phase. The Buronga 220 kV busbar was tripped following the fault, disconnecting 220 kV lines from Buronga to Red Cliffs, Balranald and Broken Hill, and as a result initiated a number of control schemes and subsequent line trips in south-western New South Wales and north-western Victoria, as well as the trip of a

[43] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/buronga-220-kv-isolator-failure-and-trip-of-multiple-transmission-elements-on-25-july-2022.pdf?la=en.

Victorian wind farm generating 31 MW. A total of 40 MW of load was disconnected at Balranald, Broken Hill, Buronga and Silverton substations.

The Murraylink very fast run back control scheme (VFRB) was initiated, but the scheme was unable to reduce Murraylink flow, resulting in the back-up trip of Murraylink. AVP, jointly with AusNet has investigated this event, identified the cause of the maloperation and implemented an upgrade to avoid Murraylink's failure to run back in future. The Victorian wind farm was disconnected due to an over-voltage protection settings error which was corrected on 30 November 2022.

11 December 2022 – Trip of Kerang-Wemen-Red Cliffs 220 kV line during a prior outage of Kiamal synchronous condenser transformer

This incident involved the simultaneous trip of the Kerang Terminal Station (KGTS)-Wemen Terminal Station (WETS)-Red Cliffs Terminal Station (RCTS) 220 kV line, as well as the synchronous condenser (syncon) transformer at Kiamal Terminal Station (KMTS). Post incident investigation by AusNet confirmed that the trip was due to a red-phase-to-ground fault caused by lightning.

On the day of the incident, 55 MW of generation was tripped due to the Wemen Solar Farm and Bannerton Solar Farm anti-islanding protection. Also, 27 MW of load supplied from Wemen, Boundary Bend and Ouyen 66 kV substations was lost due to the disconnection of WETS.

3.3 Supply-demand adequacy

The supply-demand balance in Victoria was maintained throughout 2022-23, with no directed load shedding, and no emergency reserves needing to be dispatched through RERT. In Victoria, one actual Lack of Reserve (LOR) 1[44] was declared on 16 February 2023[45] due to increased forecast operational demand; this compares to three LORs (LOR1 and LOR2) in 2021-22[46], and one LOR1 in 2020-21[47].

The declared LOR 1 condition 16 February 2023 was subsequently cancelled due to increased generator availability and net import to Victoria.

3.3.1 Victorian demand

Peak Victorian operational demand in 2022-23 was 8,988 MW at 18:00 on 17 January 2023, compared to 8,599 MW in 2021-22. Victorian maximum operational demand continued to remain relatively low compared to historical highs of 9,852 MW summer maximum in 2019-20 and 10,313 MW in 2013-14. This was driven by milder weather condition along with the continued uptake of distributed PV[48]. Similar to 2021-22, the maximum demand occurred after 17:00 AEST, which reflects the increasing trend for distributed PV generation to meet a growing proportion of underlying demand during the day. **Figure 11** shows Victoria's maximum demand levels since 2000.

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[44] For definitions of LORs (both actual and forecast), see AEMO's LOR factsheet at https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf?la=en.

[45] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/lack-of-reserve-framework-quarterly-reports/2023/q1-report.pdf?la=en.

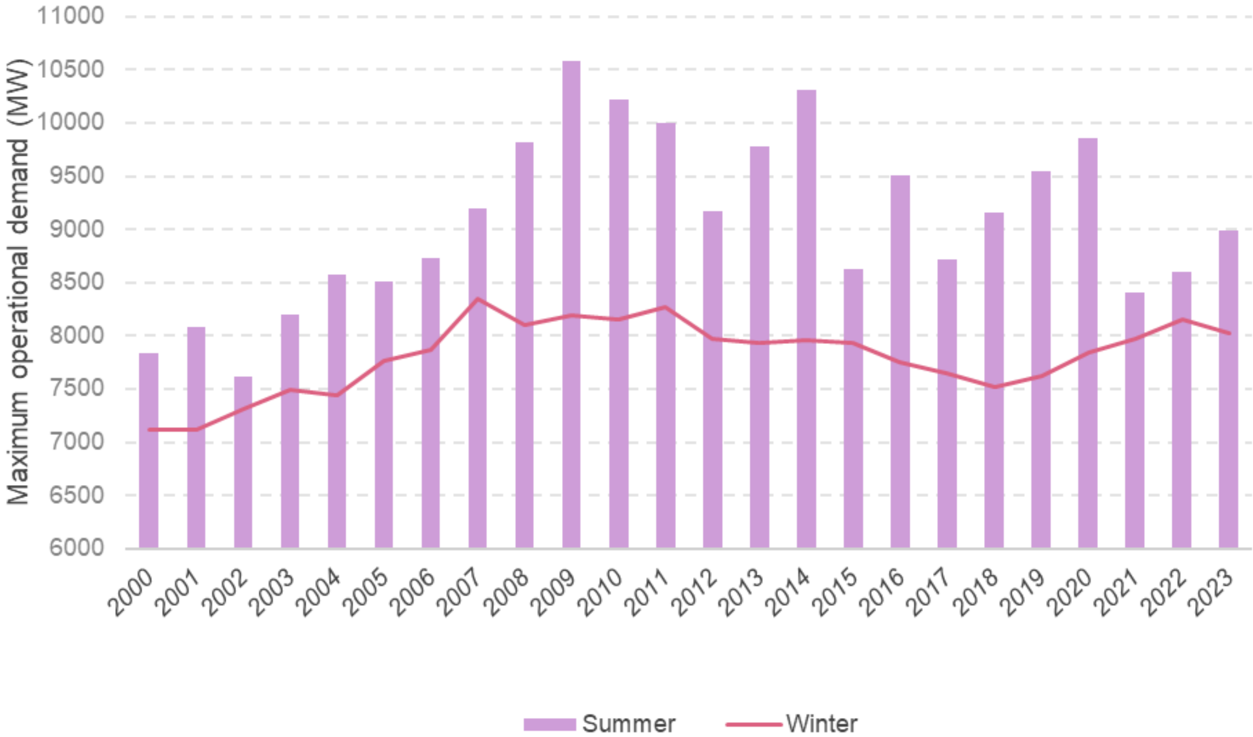
[46] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2022/2022-victorian-annual-planning-report.pdf.

[47] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/lack-of-reserve-framework-quarterly-reports/2022/q2-report.pdf?la=en.

[48] See AEMO, Quarterly Energy Dynamics, Q1 2023, at https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q1-2023-report.pdf?la=en.

Winter maximum demand did not change much from the previous year and remained at elevated levels. It was 8,018 MW on 19 June 2023 compared to the previous year's winter maximum of 8,158 MW, which was the highest since 2011. The elevated winter maximum demand is likely due to colder winters increasing the use of heating; low daytime maximum temperatures around the period of the maximum demand were below those of 2022, and below the 10-year average[49].

Figure 11 Actual maximum summer (1 Nov – 31 Mar) and winter (1 Apr – 31 Oct) Victorian operational demand, 2000 to 2023 (MW)



All-time lowest minimum operational demand occurred in 2022-23

Victoria recorded its all-time lowest minimum operational demand of 2,195 MW at 13:00 on 18 December 2022. This was 138 MW lower than the previous record set last year[50].

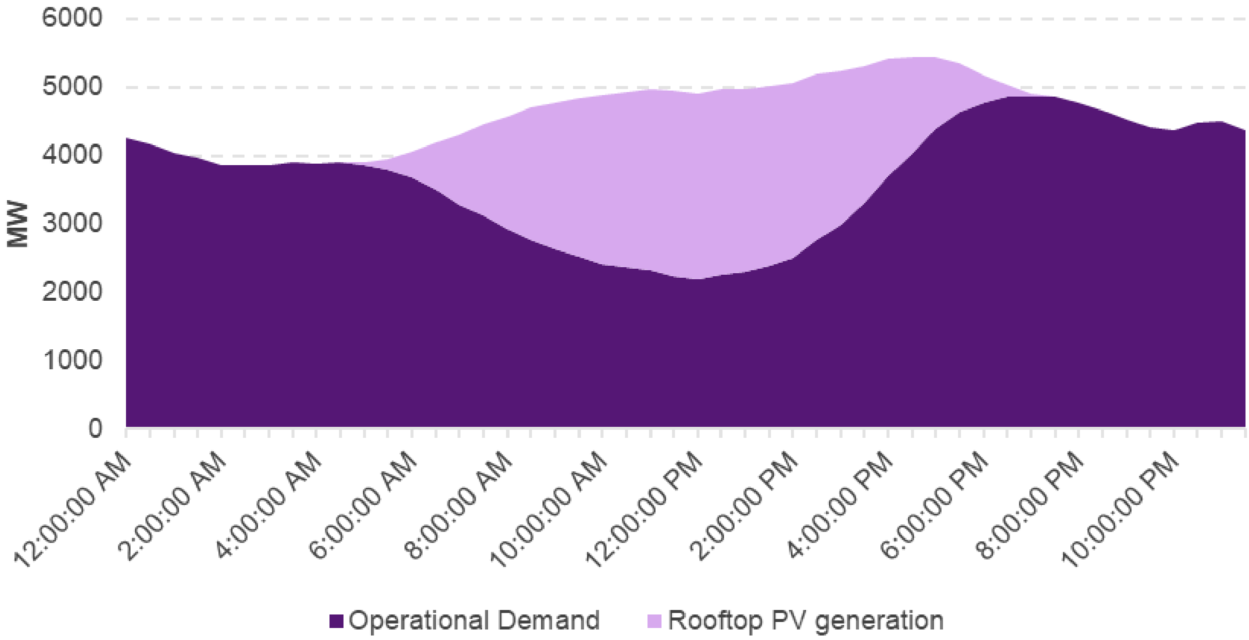
Figure 12 shows the demand profile and impact of distributed PV generation on the day of annual minimum operational demand for 2022-23. At the time of minimum demand, distributed PV met more than half (55%) of Victoria's underlying demand. For each megawatt of installed distributed PV, minimum operational demand tends to reduce between 0.7 MW and 0.8 MW (that is, a contribution of 70-80%), when accounting for the diversity of panel orientation and solar irradiation at different locations[51].

[49] See AEMO, Quarterly Energy Dynamics, Q2 2023, at https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q2-2023-report.pdf?la=en&hash=719538BE6166CB79BE1BF6B9BE82A183.

[50] At the time of 2023 VAPR publication, a new minimum operational demand record of 2,068 MW at 13:30 on 24 September 2023 had already occurred for 2023-24 (see AEMO, Quarterly Energy Dynamics, Q3 2023, at https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf).

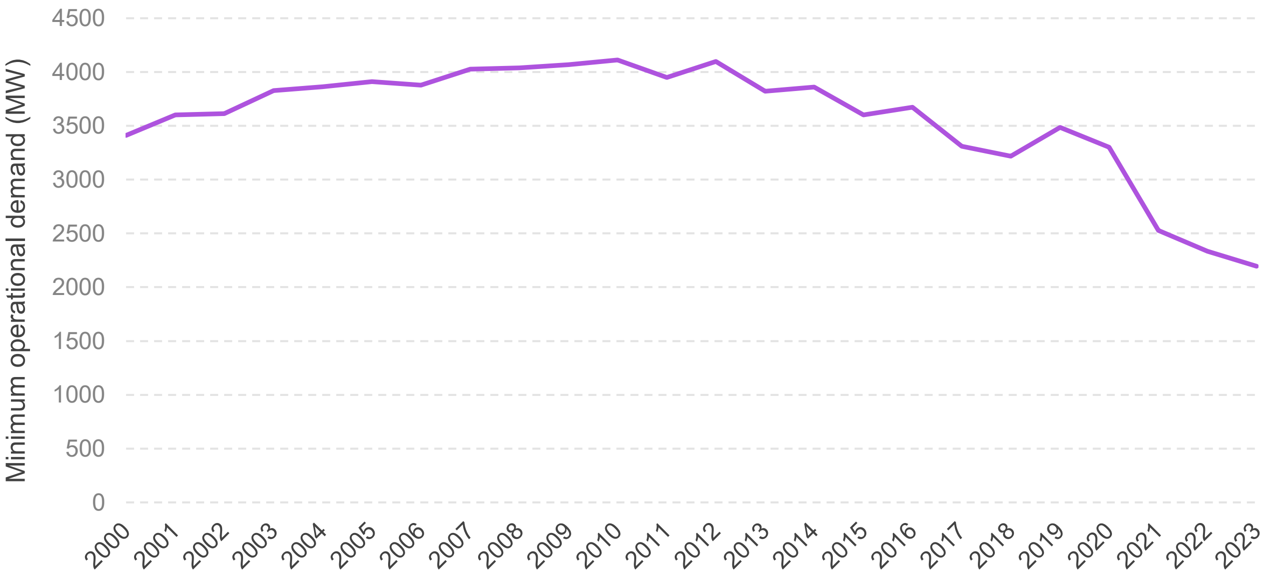
[51] See AEMO, 2023 ESOO, page 38, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf?la=en.

Figure 12 Victorian demand profile and impact of distributed PV on the day of minimum demand, 18 December 2022 (MW)



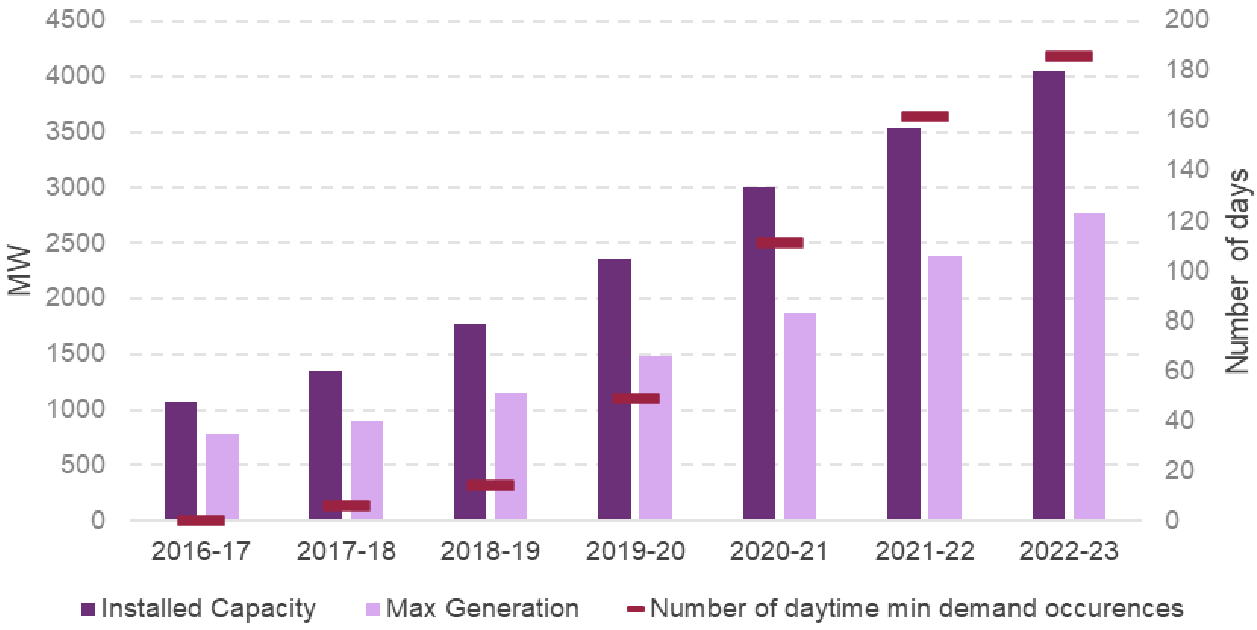
This is the fifth consecutive year the annual minimum operational demand record occurred during the day. The trend can be seen in **Figure 13**.

Figure 13 Actual minimum Victorian operational demand, 2000 to 2023



More than 500 MW of distributed PV was installed in Victoria over the 2022-23 financial year. As the installed capacity and maximum generation from distributed PV have continued to grow, daily minimum demand is occurring during daylight hours (08:00 to 17:00) more frequently. This was the case on 186 days in 2022-23, compared to 162 days in 2021-22 and 111 days in 2020-21. **Figure 14** below[52] shows the trend since 2016-17.

Figure 14 Distributed PV capacity and maximum generation by financial year and number of daytime minimum demand days, 2016-17 to 2022-23



3.4 Operational challenges

This section discusses how network operation has been impacted over the past year by the changing power system dynamics and supply geography, particularly where this has reduced system resilience, resulted in additional network constraints, or otherwise increased operational complexity.

3.4.1 West Murray observations

Voltage oscillations under prior outage conditions

AEMO continued to apply network constraints to generating units in the Western Victoria and Murray River REZs to avoid undamped voltage oscillations during prior network outages for a subsequent contingency event. The binding hours and market impact of these outage constraints have decreased in the past year from the record highs in 2021-22 (see Section 3.5), mainly due to reduced prior outages.

Sub-synchronous oscillations

AEMO first observed sub-synchronous oscillations[53] (16-19 hertz (Hz)) on the power system in 2020. Oscillations have the potential to cause damage to rotating equipment and in extreme cases could cause cascading failures.

[52] Distributed PV generation and capacity according to Australian Solar Energy Forecasting System (ASEFS) 2 measured actuals, installed capacity as of 1 July each year, see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system.

[53] See https://aemo.com.au/-/media/files/electricity/nem/network_connections/west-murray/sub-synchronous-oscillations-in-the-west-murray-area.pdf?la=en.

In May 2023, AEMO was made aware of a hypothesis that these sub-synchronous power system oscillations may contribute to the mechanical shaft damage of a synchronous condenser in this area[54].

AEMO, with support from relevant NSPs, has installed additional modern high-speed measuring equipment, Phasor Measurement Units (PMUs), at strategic locations around Victoria in the past year, to better monitor and understand sub-synchronous oscillations.

3.4.2 Reverse power flows

The increasing volume of generation sources connecting at the distribution level has resulted in reverse power flows at some terminal stations which were installed to supply customer loads. During periods of low local demand and high local generation, the power could be transferred from the distribution network to the DSN. In other words, the distribution networks at these terminal stations inject power into the DSN instead of drawing power from the DSN. From a DSN perspective, these 'reverse power flows' could reduce the effectiveness and reliability of load shedding control schemes, because these schemes could actually shed generation instead of shedding loads as designed.

In the past year, reverse power flows occurred at 15 terminal stations. While the total number of terminal stations which experienced reverse power flows remained the same as in 2021-22, the total reverse flow hours increased slightly, to 19,533 hours from 18,958 hours. **Table 3** outlines the number of hours in which reverse flows occurred at these terminal stations over the last four years, and notes the associated primary cause of reverse flows.

Table 3 Yearly statistics of reverse flows at identified locations

Terminal station	Hours with reversed flows					Primary cause
	2018-19	2019-20	2020-21	2021-22	2022-23	
Wemen 220/66 kV	1,926	3,241	3,546	3,053	3,610	Distribution network connected generation
Terang 220/66 kV	2,288	2,905	2,343	2,626	2,350	Distribution network connected generation
Kerang 220/66/22 kV	2,504	2,646	2,657	2,606	2,999	Distribution network connected generation
Horsham 220/66 kV	1,358	827	290	680	426	Distribution network connected generation
Red Cliffs 220/66/22 kV	536	477	1,933	2,192	2,636	Distribution network connected generation
Shepparton 220/66 kV	0	940	1,534	1,551	1,445	Distribution network connected generation
Ballarat 220/66 kV	0	838	1,912	1,659	1,589	Distribution network connected generation
Glenrowan 220/66 kV	0	0	592	2,582	2,617	Distribution network connected generation
South Morang 220/66 kV	0	0.5	14	56	84	Distribution network connected generation
Mount Beauty 220/66 kV	579	0	12	1,632	1,343	Distribution network connected generation
Bendigo 220/66 kV	0	0	4	24	39	Distributed PV
Cranbourne 220/66 kV	0	0	0	4	15	Distributed PV
Deer Park 220/66kV	0	0	0	18	35	Distributed PV
Morwell 220/66kV	0	1	2	38	66	Distribution network connected generation
Wodonga 330/22 kV	0	0	NA*	201	279	Distributed PV
Total	**9,191**	**11,876**	**14,839**	**18,958**	**19,533**	

*Data quality issues prevented determination of reverse flow hours for this terminal station over this period.

54 See https://aemo.com.au/-/media/files/electricity/nem/network_connections/west-murray/2023-06-28-industry-notification-on-ssr.pdf?la=en#:~:text=During%20August%202020%2C%20AEMO%20observed%20lower%20magnitude%20sub-synchronous,of%2015-20%20Hz%20based%20on%20root-mean-square%20%28RMS%29%20data.

3.4.3 Voltage management during low demand periods

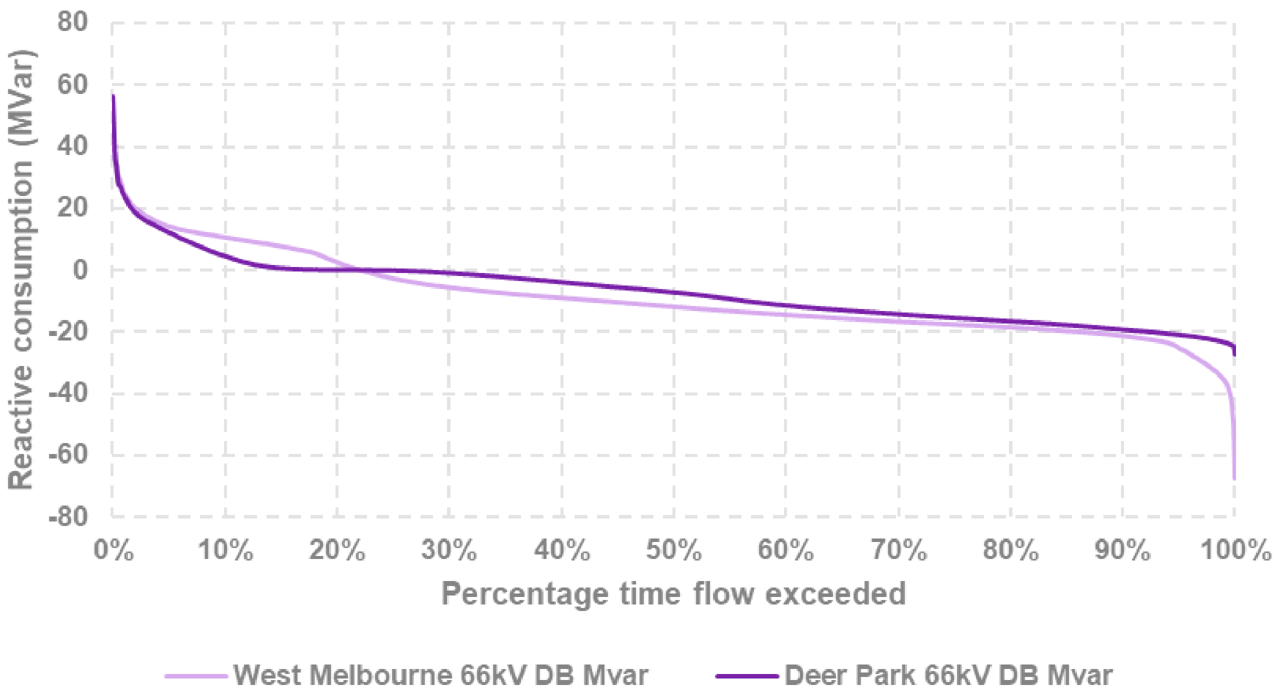
While the recent installation of 4 x 100 megavolt amperes reactive (MVAr) additional reactors at Keilor and Moorabool (the last installed in mid-2022) has greatly improved DSN voltage management during low demand periods, it did not eliminate this operational challenge entirely in the past year.

There were still occasions when normal voltage regulation measures were exhausted. For example, on 31 March 2023 and 1 April 2023 during overnight low demand periods, AEMO enabled the Keilor over-voltage protection scheme to maintain voltage within specified limits.

In addition to the low operational demand seen from the DSN, another factor which contributed to the challenges of managing high DSN voltages was reactive power injection from the distribution networks. In 2022-23, out of 32 terminal stations assessed, 13 terminal stations were found to be injecting above 30 MVAr for more than 5% of the year, and terminal stations at West Melbourne, Deer Park, Cranbourne, and Bendigo showed a consistent trend of increasing reactive power injection into the transmission network.

Figure 15 shows the yearly net reactive consumption (a negative value indicates injection into the DSN) at West Melbourne and Deer Park terminal stations as examples to demonstrate this issue. The consumed MVAr were estimated by subtracting the historical reactive power injection by respective capacitor banks, if any, from the reactive power through the transformer(s) at the locations.

Figure 15 Net reactive power flow duration curve at West Melbourne and Deer Park (MVAr)



AVP will continue to work with local distribution network service providers (DNSPs) to jointly plan how best to manage DSN voltages at times when reactive power is being injected into the DSN.

3.5 Impact of Victorian transmission constraints

This section summarises the Victorian transmission network constraints that resulted in the top 22 highest dispatch impacts during 2022-23, and compares these impacts to the outcomes during 2021-22.

The ranking of each constraint (or group of constraints) was determined by the calculated 'binding impact' of the constraints. The binding impact of a constraint is derived by combining the marginal value for each dispatch interval over the period considered. It is used to distinguish between the severity of different binding constraint equations and represents the relative financial impact associated with that constraint equation. However, it does not represent the market benefit from investment to remove the constraint in absolute terms.

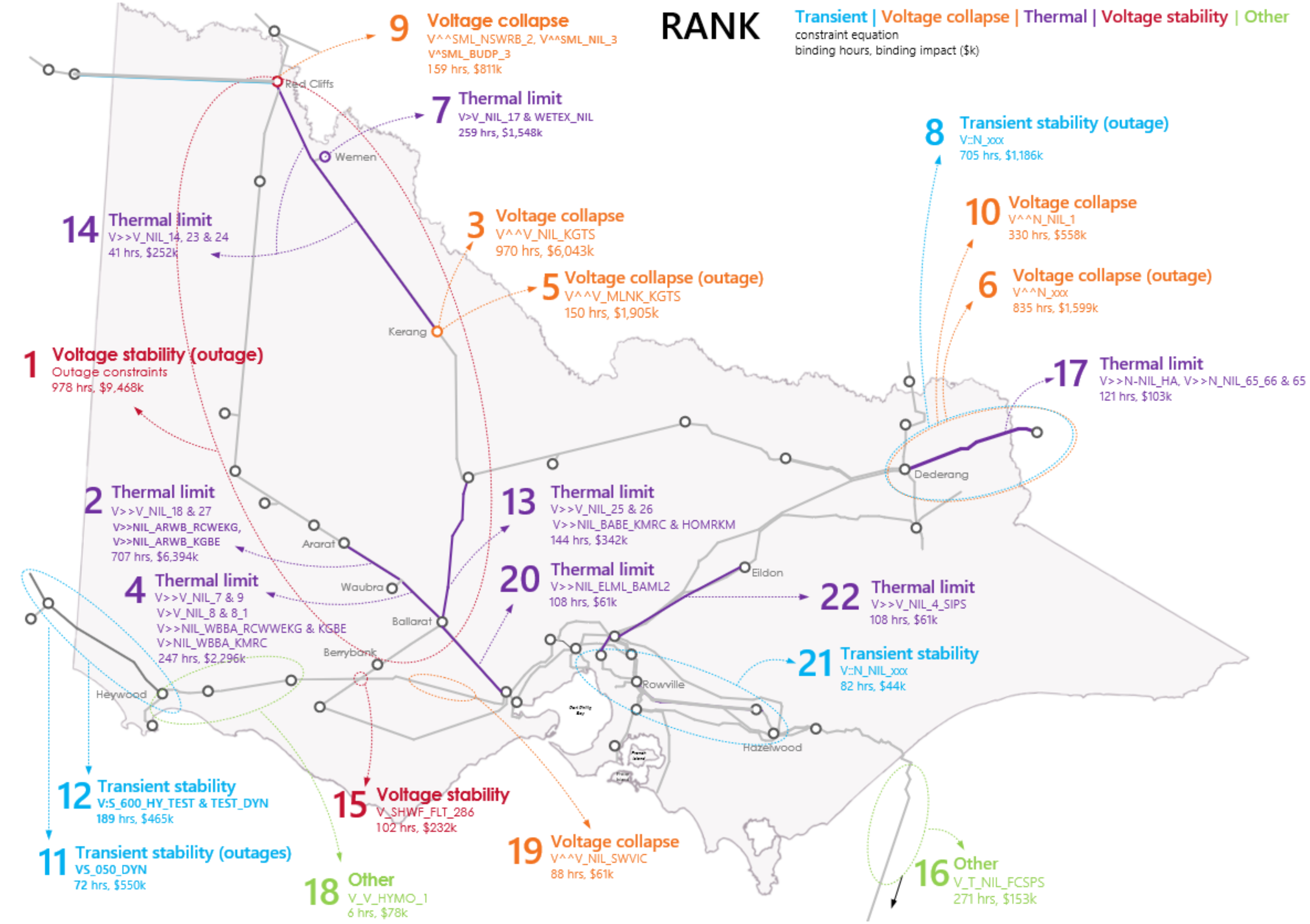
Figure 16 summarises the highest impact constraints in 2022-23 by type and location around the Victorian transmission network, as well as the binding hours and constraint impact in dollars.

While the constraints summarised in this section are those with the most significant market impact historically, investment to remove any specific constraint would also require consideration of limitations that may bind immediately behind these limits and reduce the benefits unless those constraints are also alleviated.

For example, investment to remove constraint #3 in Figure 16 would not result in unconstrained flows along Wemen to Kerang, as this line is also limited by constraint #14. In other parts of the state, constraints that currently do not bind at all may begin to bind as other limits are removed.

To assess the benefits of relieving the constraints, AVP undertakes detailed power system and economic modelling through prefeasibility and RIT-T processes (see Section 5).

Figure 16 Map of the most significant Victorian transmission constraints in 2022-23



Notes:

- Constraint impact is measured as the sum of marginal values for a constraint and provides indicative impacts on dispatch outcomes. This is a guide but does not reflect the financial impacts on individual generators, or the market benefits available under a regulatory test.
- The top ranked constraint (rank #1) represents a collection of prior outage limitations that applied during a set of planned network outages in the north-west of Victoria (see section 3.4.1 for further details).

Western Victoria and Murray River region

This part of the Victorian network (highlighted by the red dashed oval on Figure 16) is characterised by significant investment in new renewable generation and is experiencing outages to facilitate connection and commissioning of these projects. It is a relatively weak part of the Victorian network, subject to thermal, voltage stability and voltage collapse constraints that have bound more in 2022-23 than 2021-22. Of the top 10 constraints in 2022-23, seven are from this region (see **Table 4** below for more information).

Delivery of key augmentation projects planned for this region, including WRL and EnergyConnect, is expected to reduce many of these constraints. Projects being delivered as a part of the Victorian Government's RDP Stage 1 (that is, a new synchronous condenser at Ararat, a new BESS at Koorangie, Mortlake turn-in, and a number of minor augmentations), are also expected to reduce these constraints. More information about these projects is included in Section 4.

Table 4 Constraint equations with significant binding durations or impact – western Victoria and Murray River region

Rank	Equation	Binding hours		Binding impact		Description of constraint
		2021-22	2022-23	2021-22	2022-23	
1	North-west Victoria voltage oscillation (prior outage)	1,982[A]	978[A]	$21,540k[A]	$9,468k[A]	This represents a set of the network constraint equations associated with voltage oscillation during a range of prior outage conditions. Less outages have occurred in 2022-23 compared to 2021-22 and, due to this, these constraints have bound less. AEMO is continuously reviewing these constraints as revised models are obtained and based on upcoming outage schedule. AVP expects that the projects being delivered as a part of the Victorian Government's RDP (Koorangie Energy Storage System-KESS) may help reduce the impact of these constraints.
2	Ararat to Waubra thermal V>>V_NIL_18, V>>V_NIL_27, V>>NIL_ARWB_RCWEKG, V>>NIL_ARWB_KGBE	234	707	$2,948k	$6,394k	To avoid overloading Ararat to Waubra 220kV due to the loss of 220kV lines at either Kerang to Bendigo, or Red Cliffs to Wemen to Kerang. Due to the renaming of these constraints, there are many different merged constraints in this year. The increase in binding hours and impact is due to additional renewable generation coming online and contributing to this constraint. Following an RDP Stage 1 project milestone, the static ratings at Ararat have already been upgraded in August 2023. As the static ratings at Ararat has been the primary driver of this constraint, this constraint should improve next year.
3	Kerang voltage collapse V^^V_NIL_KGTS	749	970	$5,434k	$6,043k	To avoid voltage collapse at Kerang due to the loss of Horsham – Murra Warra – Kiamal 220kV line considering Murraylink Very Fast Run Back (VFRB) scheme disabled. It is expected that EnergyConnect and Victorian Government's RDP projects (see section 4.5.2) may reduce the impact of this constraint.

Rank	Equation	Binding hours		Binding impact		Description of constraint
		2021-22	2022-23	2021-22	2022-23	
4	Waubra to Ballarat thermal V>>V_NIL_9, V>>V_NIL_7, V>>NIL_WBBA_RCWWEKG, V>>NIL_WBBA_KGBE, V>V_NIL_8, V>V_NIL_8_1, V>NIL_WBBA_KMRC	197	247	$2,297k	$2,296k	To avoid overloading Waubra to Ballarat 220 kV line on trip of the Red Cliffs-Wemen-Kerang 220 kV line or Kiamal to Red Cliffs 220 kV line or Kerang to Bendigo 220 kV line. It is expected that minor augmentations as part of the Victorian Government's RDP Stage 1 projects and Western Renewable Link project increase the thermal capability of the Ballarat – Waubra – Ararat – Crowlands – Bulgana – Horsham – Murra Warra – Kiamal 220 kV line, and thereby reduce the impact of this limitation.
5	Wemen to Kerang voltage collapse V^^V_MLNK_KGTS	266	150	$3,508k	$1,905k	To avoid voltage collapse at Kerang due to the loss of Horsham – Murra Warra – Kiamal 220kV line during an outage of Murraylink.
7	Wemen Transformer thermal[B] V>V_NIL_17, V>NIL_WETS_NIL	106	259	$421k	$1,548k	Prevent pre-contingent overload of Wemen 220/66 kV transformer in the 66 to 220kV direction (not part of DSN).
9	Red Cliffs voltage stability V^^SML_NIL_3 V^^SML_NSWRB_2 V^SML_BUDP_3	87	159	$237k	$811	To avoid voltage collapse at Red Cliffs for the loss of Bendigo to Kerang 220kV, Darlington Point to Balranald (X5) or Balranald to Buronga (X3) 220 kV lines when the New South Wales Murraylink runback scheme is unavailable. V^SML_BUDP_3 is to avoid voltage collapse for loss of Bendigo to Kerang 220 kV line. This is an outage constraint at the time of Buronga to Balranald (X3) or Balranald to Darlington Pt (X5) outage. .It is expected that EnergyConnect will reduce the impact of this constraint.
13	Ballarat to Bendigo thermal V>>V_NIL_25[c], V>>NIL_BABE_HOMRKM[D], V>>V_NIL_26[c], V>>NIL_BABE_KMRC[D]	40	144	$123	$342k	To avoid overloading Ballarat to Bendigo for loss of Horsham – Murra Warra – Kiamal 220kV or Kiamal to Red Cliff 220kV lines.
14	Red Cliff – Wemen – Kerang thermal V>>V_NIL_24[E], V>>V_NIL_14[E], V>>V_NIL_23[E]	59	157	$403k	$252k	To avoid overloading the Red Cliff – Wemen – Kerang 220kV line for the loss of Horsham – Bulgana – Crowlands 220kV line or Horsham – Murra Warra – Kiamal 220kV line. A project to remove station limitations at Wemen and Kerang Terminal Stations and install windspeed monitoring on the Wemen to Kerang line, was completed in 2021. This project has increased the available headroom of these constraints during the winter and shoulder periods, however during summer these constraints have continued to bind.

A. This is the sum of the binding hours and binding impacts for multiple constraint equations during prior outage and system normal conditions (35 in 2022 and 45 in 2021). Many of these individual constraints bound concurrently.
B. These transformers are not DSN assets but have been included for completeness.
C. These are new constraints effective from May 2022.
D. These are new constraints effective from March 2023.
E. V>>V_NIL_24 has recently been replaced by new equation V>>NIL_WEKG_HOBUCW.
V>>V_NIL_14 has recently been replaced by new equation V>>NIL_WEKG_HOMRKM.
V>>V_NIL_23 has recently been replaced by new equation V>>NIL_RCWE_HOBUCW.

South West corridor and the Heywood interconnector

This area encompasses some of the bigger wind farms in Victoria (such as Stockyard Hill, Dundonnell and Macarthur), and the alternating current (AC) interconnection to South Australia through Heywood Terminal

Station. New constraints have emerged in the south-west corridor in Victoria recently, and existing constraints bound more frequently than the previous year. This is due to both new Victorian generators connecting in this corridor, and new limitations emerging on the Heywood interconnector to manage secure operation in South Australia. Delivery of EnergyConnect is expected to help alleviate constraints on the Heywood interconnector. **Table 5** presents further details on each of these limitations.

Table 5 Equations with significant binding durations or impact – south-west corridor

Rank	Equation	Binding hours		Binding impact		Description
		2021-22	2022-23	2021-22	2022-23	
11	Heywood transient stability (outages) VS_050_DYN	14	72	$123k	$550k	Limiting Heywood interconnector flow to 50 MW in Victoria to South Australia direction maintaining oscillatory stability during outages.
12	Heywood transient stability V:S_600_HY_TEST and V:S_600_HY_TEST_DYN	140	189	$385k	$465k	This constraint represents a 600 MW transfer limit on Victoria to South Australia to ensure oscillatory stability in system normal condition. These transient stability constraints (both system normal and outage) are expected to be removed after the completion of EnergyConnect (see Section 4.5.2)
15	Stockyard Hill Wind Farm system strength V_SHWF_FLT_286	41	108	$2,036k	$310k	Limit generation at Stockyard Hill wind farm to 286 MW for system strength when Heywood flows from South Australia to Victoria exceed 470 MW. This limit is currently being reviewed.
18	Limiting voltage unbalance Heywood-Alcoa Portland (APD) V_V_HYMO_1	-	6	-	$78k	Limit voltage unbalance at the APD 500 kV bus and Heywood 275 kV bus. This has a high impact with less binding hours. This constraint is expected to be improved after Mortlake Power Station (MOPS) turn in (see Section 4).
19	Haunted Gully to Moorabool And Mortlake to Moorabool Voltage collapse V^^V_NIL_SWVIC[A]	-	88	-	$61k	To manage flow towards Moorabool across Haunted Gully to Moorabool and Mortlake to Moorabool 500 kV lines due to the loss of Haunted Gully to Moorabool 500 kV line and both APD potlines. The Mortlake Power Station (MOPS) turn-in project, as a part of the Victorian Government's RDP, will improve the situation, as will the new terminal station at Cressy (see Section 4.5.2).
20	Elaine to Moorabool thermal V>>NIL_ELML_BAML2[A]	-	108	-	$61k	To avoid overloading Elaine to Moorabool 220 kV line on trip of Ballarat to Moorabool No. 2 220 kV line. WRL is expected to address this issue (see Section 4.5.1).

A. These are new constraints effective from August 2022

Eastern Victoria, Victoria – New South Wales Interconnector and Latrobe Valley

Constraints in the east of Victoria are primarily dominated by the limitations across VNI East. There are several thermal constraints limiting flows between South Morang and Murray, while voltage and thermal limits flow across the border region. **Table 6** provides further details on these limitations.

Table 6 Equations with significant binding durations or impact – Eastern Victoria, VNI East and Latrobe Valley

Rank	Equation	Binding hours		Binding impact		Description
		2021-22	2022-23	2021-22	2022-23	
6	VNI export voltage collapse during outages V^^N_xxx	634	835	$1,679k	$1,599k	Avoid voltage collapse around Murray for loss of all APD potlines during planned transmission equipment outages. These constraints each behave similarly to their system normal counterpart V^^N_NIL_1. These constraints are invoked during outages of any line in, or connecting to, the 330kV corridor between Victorian and New South Wales capital city load centres. Outages of other significant lines including 500kV Latrobe Valley lines in Victoria and 220kV lines in Southwest New South Wales also may require such constraints to be invoked. The market impact of this constraint is expected to reduce during 2023-24 now that the VNI East project is complete (detailed in Section 4.1.1).
8	VNI export transient stability during outages V::N_xxx	694	705	$1,679	$1,186k	Prevent transient instability for fault and trip of Hazelwood to South Morang line during planned transmission equipment outages. The market impact of this constraint was mainly driven by outages of the Dederang to South Morang 330 kV lines and South Morang series capacitors in 2022.
10	VNI voltage collapse V^^N_NIL_1	734	330	$8,917k	$558k	To avoid voltage collapse in northern Victoria and southern New South Wales for loss of APD potlines following fault on one of the 500 kV lines in Southwest Victoria. The frequency of binding this constraint has been reduced.
16	Basslink limit V_T_NIL_FCSPS[A]	175	271	$74	$153k	To limit Basslink flow from Victoria to Tasmania while the FCSPS is enabled. This constraint binds depending on the load enabled for arming.
17	VNI thermal overload V>>N_NIL_65_66 V>>N_NIL_65 V>>N-NIL_HA	124	121	$1,318k	$103k	To prevent overloading of VNI, Murray to Upper or Lower Tumut line both pre-contingent and post-contingent for loss of Murray to Lower Tumut or Upper Tumut line.
21	Transient stability V::N_NIL_xxx	39	82	$16k	$44k	To prevent transient instability for fault and trip of Hazelwood to South Morang line during system normal.
22	Eildon to Thomastown thermal V>>V_NIL_4_SIPS[B]	-	2	-	$41k	To avoid overloading Eildon to Thomastown 220 kV line for loss of one of the Dederang to South Morang 330 kV lines. This constraint manages the Eildon to Thomastown line flow to its 5 mins rating, when the System Integrity Protection Scheme (SIPS), provided by the Victorian Big Battery, is available.

A. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/operation-of-frequency-control-special-protection-scheme-in-tasmania.pdf?la=en.
B. V>>V_NIL_4_SIPS has recently been replaced by new equation V>>NIL_EPTT_DDSM_SIP.

3.6 Interconnector capability

An interconnector's capability depends on the conditions within the network, which vary throughout the year. AEMO publishes notional interconnector limits in the IASR[55], and a detailed summary of the capability and limits of each interconnector in the NEM in its Monthly and Annual NEM Constraint Reports[56].

Following the completion of the VNI East upgrade project in late 2022, its exporting capability has initially increased by about 40 MW[57] (see Section 4.1.1 for more information about VNI Minor).

The Heywood interconnector continues to operate below its maximum design limit of 650 MW in both directions, due to stability risks which were identified following the South Australia black system event in 2016. The maximum transfer currently allowed is 600 MW from Victoria to South Australia, and 550 MW from South Australia to Victoria. AVP, ElectraNet and AEMO are currently progressing work to release the full design capacity of this interconnection, with a plan to increase the South Australia to Victoria transfer limit to 600 MW initially, then to 650 MW in both directions following commissioning of EnergyConnect Stage 1 in mid-2024.

Refer to Appendix A1 for more information on how the Victorian interconnectors performed over the past 12 months.

3.7 Behaviour of DSN at time of high network stress

To understand how the DSN performed at times of high stress, AVP identified a series of snapshots which represent unfavourable operating conditions in the last year, to give a comprehensive picture of DSN network performance under stress. These snapshots focus on network stress arising from maximum and minimum demand (both day and night) and high renewable (wind) generation, to assess periods in which these quantities were at their most extreme or most limited by network conditions. **Table 7** provides a summary of the selected snapshots for analysis.

Table 7 Summary of snapshots in 2022-23

Snapshots	Conditions	Occurring date and time	Operational condition
Demand	Maximum Victorian demand	17/01/2023 18:00	Various generation mix (both VRE and synchronous generators
	Minimum Victorian demand (daytime)	18/12/2022 13:00	Fewer synchronous generators online, solar units online and ubiquitous rooftop PV
	Minimum Victorian demand (night-time)	05/02/2023 04:30	Fewer synchronous generators online but with no rooftop PV
Wind	Maximum wind generation in Victoria	08/06/2023 21:00	Extensive grid-scale VRE
Interconnectors	Maximum export through VNI	27/06/2023 22:00	Surplus generation in Victoria

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

56 See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams.

57 The total increase in notional exporting capability will be 170 MW, to 870 MW from the existing 700 MW, after completion of EnergyConnect Stage 2 and Western Renewable Link. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/2020/vni-rit-t/victoria-to-new-south-wales-interconnector-upgrade-rit-t-pacr.pdf?la=en&hash=0564037FF5BFD025B8A8E7EA3CBD9743.

Key insights from these 2022-23 snapshots are:

- Under maximum demand conditions, the DSN element with the highest system normal ('n') loading was the Rowville A1 transformer, which reached 70% of its continuous rating. Using the snapshot to test DSN loadings following credible contingencies, the DSN elements with the highest modelled post-contingent ('n-1') loading were the Geelong to Moorabool No.1 and No.2 lines loaded at 98% of their emergency rating for the loss of the parallel line.
- Due to the installation of two 100 MVAr reactors at Moorabool in July and August 2022, to manage high DSN voltages, the performance of the DSN under minimum demand conditions improved compared to last year's minimum demand case.
- At the time of maximum wind generation in Victoria in 2022-23, the Ararat to Waubra, Waubra to Ballarat, Ballarat to Bendigo and Elaine to Moorabool lines were approaching their post-contingent thermal limits, suggesting the existing market constraint equations are operating effectively. The commissioning of WRL and VNI West are both expected to help relieve these limits.
- Maximum export conditions occurred in June 2023 when Victorian regional demand was moderate and approximately 40% of Victorian generation consisted of renewables, including approximately 2,000 MW of wind generation. The VNI export level was limited by voltage collapse constraints.

Appendix A2 provides more information on the minimum demand, maximum wind generation and maximum export snapshots. The remainder of this section focuses on the performance of the network under maximum demand conditions, which is of most relevance for this year's Annual Planning Review.

3.7.1 Maximum demand snapshot

The maximum demand snapshot captures the conditions when many network elements experience their maximum loading. It is based on power system characteristics observed at 18:00 on 17 January 2023, when demand reached an annual peak of 8,988 MW.

At the time of maximum demand, the southward flows into Victoria across VNI East and westward flows across the Heywood interconnector from Victoria to South Australia were not limited by constraints. The flows across Murraylink to South Australia were limited to avoid voltage collapse at Red Cliffs. The Buronga syncon in New South Wales tripped off this day, resulting in the offload of 94 MW solar generation in South West New South Wales.

During the time of maximum demand, all DSN elements were loaded below their system normal ('n') and post-contingent ('n-1') limits. In system normal, the DSN element with highest n loading was the Rowville A1 transformer, at 70% of its continuous rating. Loading of the Rowville A1 transformer under system normal has been identified as an emerging limitation in this 2023 VAPR; further detail is in Section 5.2.2.

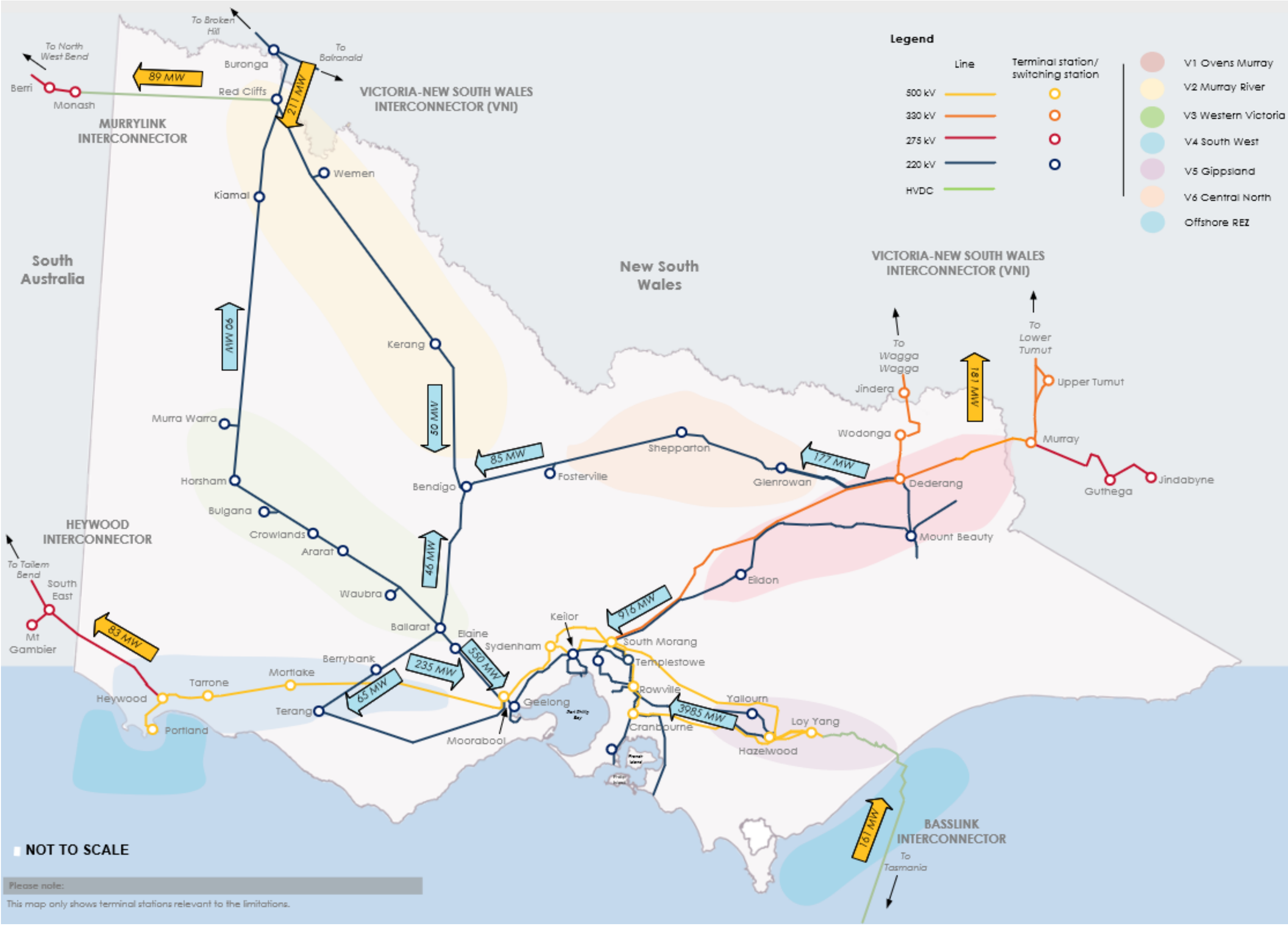
The DSN elements with highest modelled post contingency ('n-1') loading were the Geelong to Moorabool No. 1 and No. 2 lines, loaded at 98% of their emergency rating for the loss of the parallel line. To avoid overloading for the loss of one (parallel) line, the switching arrangement at Keilor was temporarily changed to encourage more power to flow through the Keilor 500/220kV transformers. System normal constraints were introduced in January 2023 to manage loading on Moorabool to Geelong feeders for a trip of the parallel line. Overloading of the Moorabool – Geelong lines for trip of a parallel line has been identified as an emerging limitation in this 2023 VAPR; further detail is in Section 5.2.2.

The ‘n’ and ‘n-1’ ratings and loadings for each DSN element during the maximum demand snapshot are detailed in the historical DSN rating and loading workbook[58].

In addition to elements approaching thermal limits, the voltage at the Deer Park 220 kV bus was observed to be at its lower limit for the loss of Deer Park to Keilor 220 kV line during the maximum demand snapshot. At the time, the load at Deer Park reached a new historical maximum record of 266 megavolt amperes (MVA). The need for absorbing reactive support at Deer Park for trip of the Deer Park – Keilor line was identified in the 2022 VAPR and included in the Metropolitan Melbourne Voltage Management RIT-T. Further detail can be found in Section 5.2.1.

Figure 17 shows the direction and magnitude of power flows through significant DSN corridors during maximum demand, with Melbourne’s 6.1 GW of load being supplied via the Eastern Metro, Northern Metro, and Western Metro corridors.

Figure 17 Map of power flows along significant corridors during maximum demand (18:00 on 17 January 2023)



58 See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

4 Update on network developments already progressing

The information provided in this section sets out the key network developments assumed in the Annual Planning Review and Transmission Development Plan for Victoria presented in Section 5, highlighting progress since the 2022 VAPR. It includes updates on network developments within Victoria and interconnections with neighbouring states.

Key insights

- Victoria's rapid energy transition is being driven by large-scale renewable energy generation, so far mostly developed in the west of the state, and the strong uptake of distributed generation by consumers.
- The majority of the network and non-network developments currently being progressed in Victoria through its Transmission Development Plan, such as RDP stage 1, WRL and VNI West, serve to reduce congestion and more efficiently harness this renewable generation development for consumers.
- The Transmission Development Plan for Victoria is designed to deliver security and reliability objectives in the context of Victorian Government policy and regulatory settings. The investments in the plan help reduce overall costs to consumers by unlocking lower-cost generation supplies, increasing power system resilience, and improving the efficiency of resource sharing between neighbouring regions.
- Together these projects target key thermal, stability, voltage control, system strength, and REZ expansion limits across the state and interconnector transfer limits with neighbouring states.
- The Transmission Development Plan is updated annually. For this 2023 VAPR, the network developments discussed in this section are assumed to proceed and any updates to the plan reflect emerging limitations in the past year.

4.1 Transmission developments projects in Victoria

To address the emerging operational challenges and deliver a system capable of facilitating the supply and demand changes highlighted in Section 2, AVP has been progressing a suite of transmission development projects.

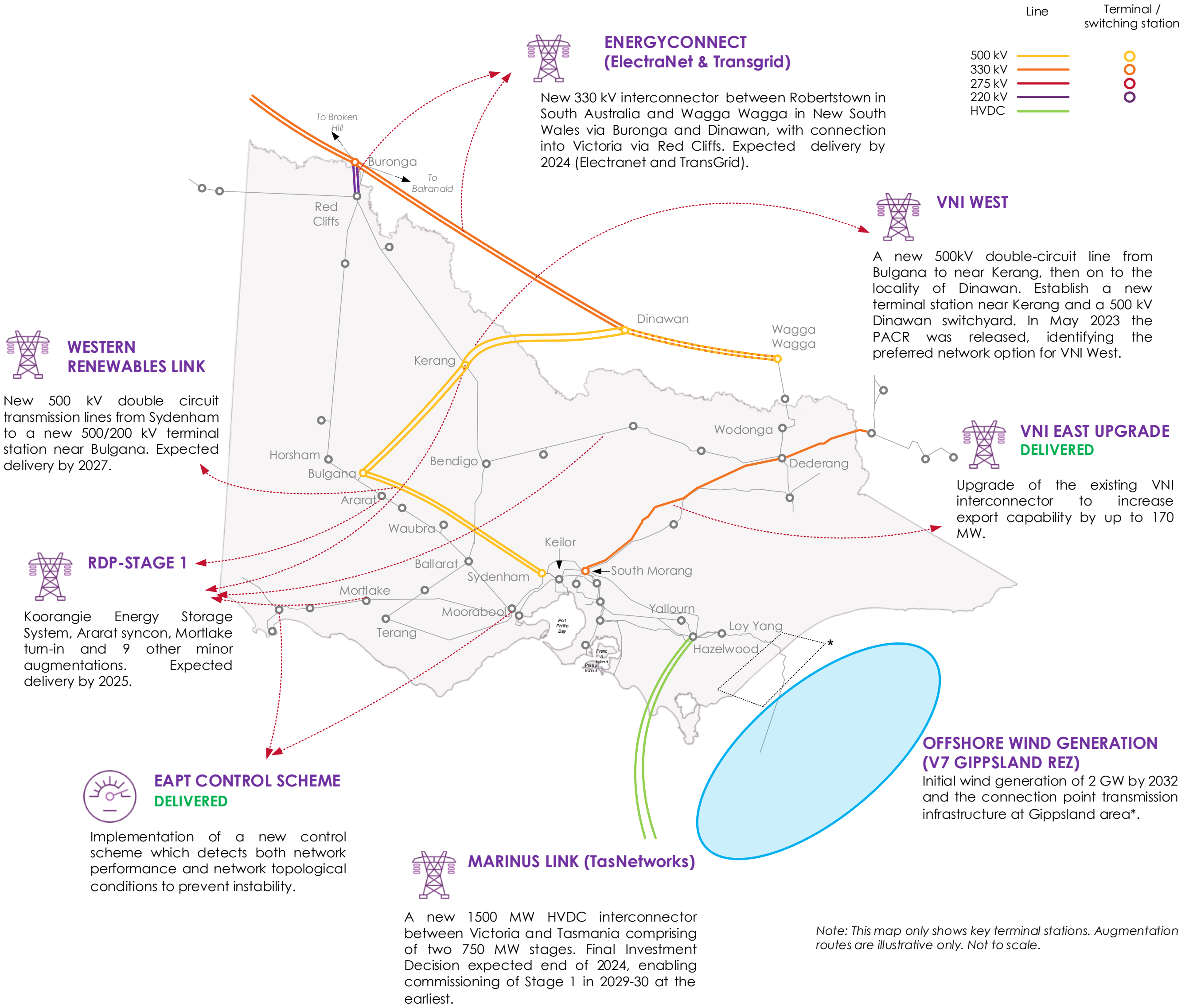
Over the 10-year VAPR outlook, these projects will facilitate the connection of new generation, increase network capacity to transfer power between new supply centres and demand, and manage emerging operational challenges before they arise. Combined, these projects help to efficiently deliver network performance as outlined in the NER, maintain supply reliability, and minimise overall costs to consumers in the context of Victorian Government policy and regulatory settings.

Figure 18 shows the transmission development projects that AVP included in the base case when undertaking the Annual Planning Review for 2023, presented in Section 5. These projects are either:

- **Delivered projects** – projects completed since the publication of 2022 VAPR.
- **Other planned projects** – this includes all committed and anticipated projects according to the ISP commitment criteria in the ISP Methodology[59], as well as transmission projects initiated by VicGrid as part of the RDP.

The remainder of this section provides further details about each project, including high-level scope and progress since the 2022 VAPR.

Figure 18 Base case network and non-network development projects for Victoria



* Gippsland connection point area of interest for investigation; see https://engage.vic.gov.au/project/offshore-wind-transmission-in-gippsland-and-portland/page/development-and-engagement-roadmap.

[59] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

4.1.1 Delivered projects

The following projects reported as committed in the 2022 VAPR have since been completed:

- **VNI Minor (also named VNI East Upgrade)** – the upgrades to the existing Victoria – New South Wales Interconnector (VNI East) have been completed. Installation and energisation of a second 500/330 kV transformer at South Morang Terminal station was completed in March 2023. Re-tensioning of the 330 kV South Morang – Dederang lines (and associated works) was completed in August 2023. Installation of power flow controllers on the Upper Tumut to Canberra and Upper Tumut to Yass 330 kV lines was completed in February 2023. See Section 3.4 of the 2022 VAPR[60] for more information about this project.
- **EAPT Scheme upgrades** – AVP has implemented the changes to the Emergency Alcoa Portland Tripping (EAPT) Scheme based on the recommendation of the Victoria control scheme review as outlined in the 2020 VAPR. Now the EAPT scheme detects both network performance (including frequency and voltage) and network topological conditions to prevent instability in the network by separating the Victorian network from South Australia at Heywood. This upgrade introduced the topological criteria which reduces the likelihood of maloperation and ensures that the scheme only operates for events in the South West Victorian region, rather than events on the wider network.

4.1.2 Other planned projects

Renewable Energy Zone Development Plan (RDP) Stage 1

The Victorian Government's RDP Directions Paper[61] published in February 2021 identified potential network augmentations that would relieve existing constraints on the Victorian DSN and facilitate the connection of future generators. In August 2021, the Victorian Government directed AVP to progress procurement activities for three contestable projects for services to strengthen the system, as well as three sets (totalling nine projects) of non-contestable minor network augmentations.

In January 2022, the Victorian Government also directed AVP to progress procurement activities for turn-in of the Haunted Gully to Tarrone 500 kV line at Mortlake. In October 2022, the Victorian Government issued the Third REZ Stage 1 *National Electricity (Victoria) Act 2005* (NEVA) Order directing AEMO to enter into contracts with the declared transmission system operator for the network augmentations identified through the procurement process[62].

Table 8 summarises projects planned under the RDP Stage 1.

[60] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2021/2021-victorian-annual-planning-report.pdf?la=en.

[61] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0016/512422/DELWP_REZ-Development-Plan-Directions-Paper_Feb23-updated.pdf.

[62] Victoria Government Gazette No. S547, 14 October 2022, at http://www.gazette.vic.gov.au/gazette/Gazettes2022/GG2022S547.pdf.

Table 8 RDP Stage 1 system strengthening projects

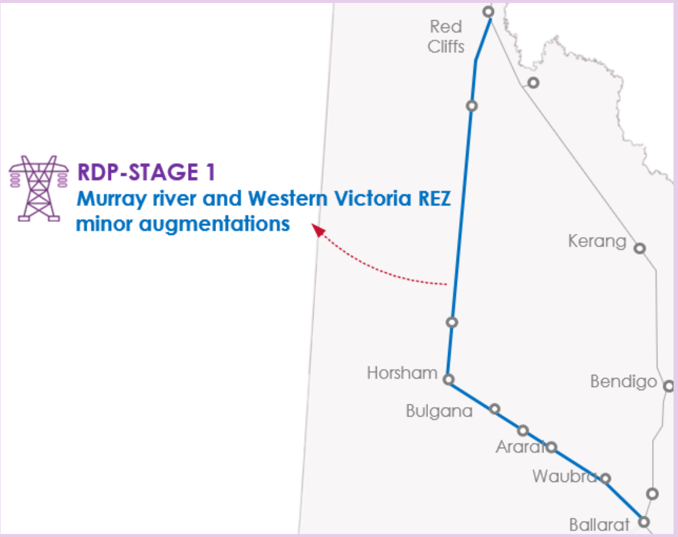
Project	REZ	Purpose	Description and scope
Mortlake Turn in	V4 - South West	Improving voltage stability in the South West REZ has the potential to allow up to 1,500 MW of additional renewable generation[A].	• Installing four new 500 kV circuit breakers and associated equipment to fully populate one existing 500 kV bay and establish a new 500 kV bay at Mortlake Power Station. • Connecting the existing Haunted Gully to Tarrone 500 kV circuit, of the Moorabool to Heywood 500 kV double circuit line, into Mortlake Terminal Station to establish a Haunted Gully to Mortlake 500 kV circuit and a Mortlake to Tarrone 500 kV circuit. The project is expected to be completed by October 2025.
Koorangie Energy Storage System (KESS)	V2 – Murray River	Improving the system strength in Murray River REZ hence increasing the potential for connection of additional renewable generation. Additional renewable generation up to 300 MW can be supported by the KESS with the support of its grid-forming technology.	• Establishing a new 220 kV terminal station, located approximately 15 km north-west of the existing Kerang Terminal Station, connecting into the existing Kerang – Wemen 220 kV line. • Establishing a new 125 MW / 250 MWh battery energy storage system with grid-forming inverters, to be connected to the new terminal station near Kerang. Currently the project is in the development stage and the expected delivery date of the project is late 2025. The KESS will provide system strength services for 20 years as part of the service agreement with AEMO[B].
Ararat synchronous condenser	V3 – Western Victoria	Improving the system strength in Western REZ and providing dynamic voltage and reactive power control capability. Ararat synchronous condenser is expected to allow the stable connection of up to 600 MW of additional generation.	• Installation of a synchronous 250 MVA synchronous condenser and the associated primary and secondary equipment at existing Ararat Terminal Station. • The project is currently undergoing detailed design. Expected completion date of the project is late 2025 with a 20 year service agreement[C].

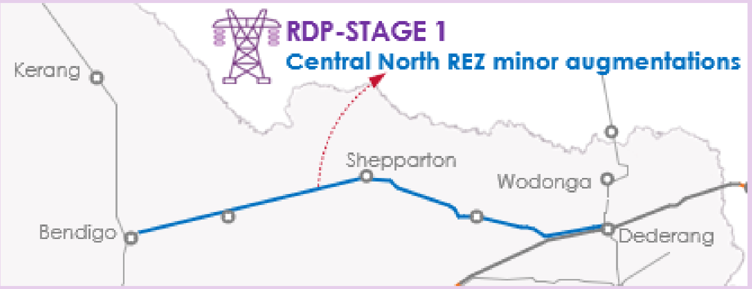
A. See https://aemo.com.au/en/newsroom/media-release/aemo-completes-procurement-for-victorian-government.
B. See https://aemo.com.au/en/newsroom/media-release/aemo-awards-contract-to-improve-system-security-in-murray-river-rez.
C. See https://aemo.com.au/en/newsroom/media-release/aemo-awards-contract-to-improve-system-security-in-western-victoria-rez.

Table 9 below provides a summary of the minor augmentations to be carried out in West Murray, South West and Central North REZs in Victoria as part of RDP Stage 1.

The purpose of these minor augmentations is to alleviate the existing thermal constraints to allow additional low-cost renewable generation in regional Victoria to connect to the NEM. The majority of these minor augmentations are expected to be completed by October 2025.

Table 9 Summary of RDP Stage 1 minor augmentation projects – all projects aimed at relieving thermal constraints

REZ	Project	Description and scope of work
V4 – South West 	Ballarat – Terang – Moorabool thermal loading control scheme	Implementing an automatic generator runback control scheme to avoid thermal overloading on Ballarat – Berrybank – Terang – Moorabool 220 kV link post contingency (trip of Ballarat to Berrybank 220 kV line)
	Heywood to Moorabool 500 kV line uprating (substation / auxiliary upgrade and dynamic line rating)	Install wind monitoring facilities to realise higher thermal capacity ratings. Upgrade interplant limitations (such as switch to circuit breaker conductor sections) within the Moorabool and/or Heywood terminal station/s to increase the Heywood to Moorabool 500 kV line rating
	Sydenham to Keilor line uprating (station upgrade)	Upgrade interplant assets to remove the limitations (such as switch to circuit breaker conductor sections) within the Sydenham and/or Keilor terminal station/s to increase the Sydenham to Keilor 500 kV line rating.
	Moorabool 220 kV transformer (MLTS) station upgrade	Upgrade interplant limitations (such as switch to circuit breaker conductor sections) within MLTS to match MLTS transformer short-term ratings.
V2 – Murray River **V3 – Western Victoria** 	Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana thermal loading control scheme	Install a generator runback/tripping scheme to quickly reduce the output of local generators to avoid overload of the Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana 220 kV lines. This scheme is expected to operate to prevent overload following trip of either: • Bendigo – Kerang 220 kV line • Red Cliffs – Wemen – Kerang 220 kV line
	Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana thermal overloading scheme with Murraylink runback for Murraylink import conditions	Modify the existing Murraylink Very Fast Run Back (VFRB) to operate during Murraylink on import (from South Australia to Victoria) to manage thermal loading on Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana 200 kV link during contingency conditions.
	Ararat, Waubra, Ballarat, Bulgana and Kiamal terminal station interplant upgrades	Upgrade interplant limitations at Ararat, Waubra, Ballarat, Bulgana and Kiamal to allow full utilisation of the 220 kV line ratings.

REZ	Project	Description and scope of work
V1 and V6 	Dederang – Glenrowan – Shepperton– Bendigo circuit thermal loading control scheme	Implementing an automatic generator runback control scheme to manage the thermal loading in 220 kV lines between Dederang and Bendigo for runback proposed Axedale Solar Farm. This scheme is expected to operate to prevent overload following trip of either: • Eildon – Thomastown 220 kV line • Bendigo – Kerang 220 kV line • Dederang H1 DBUSS operation • Fosterville – Shepparton 220 kV line
	Central North REZ augmentation #2: DDTS 330 / 220 kV transformer (secondary cooling system)	Install a control scheme that automates the enablement of the cooling system on the DDTS H3 transformer, thereby allowing the 340 MVA short-term rating to be used at all times, effectively increasing the transformer rating from 240 MVA to 340 MVA.

Western Renewables Link

The Western Victoria region is experiencing significant renewable generation development, with large amounts of additional generation expected to be operational in the near future. However, transmission infrastructure in this region is currently insufficient to allow efficient access to all generation seeking to connect.

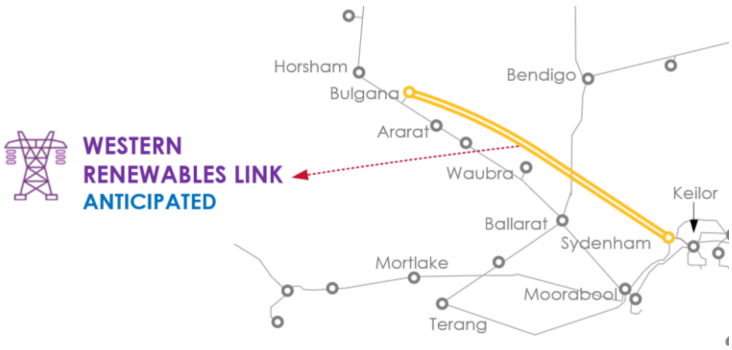
In July 2019, AVP completed a RIT-T (previously known as the Western Victoria Transmission Network Project RIT-T) to unlock renewable energy resources, reduce network congestion, and improve utilisation of existing assets in western parts of Victoria[63]. In December 2019, AusNet Services was awarded a contract to consult on design and seek planning approvals to build, own, operate and maintain the preferred transmission augmentations identified by the RIT-T.

In May 2023, following investigations in relation to the VNI West transmission project and the release of the VNI West PACR, the Victorian Minister for Energy and Resources Issued order S 267, 27 May 2023 (May NEVA Order) in relation to WRL and VNI West. The effect of the May NEVA Order is to allow the WRL Project to progress many elements of the project based on an augmented scope including the construction of a new 500 kV double circuit transmission line from Sydenham to Bulgana (referred to as the uprate). The order explains why such a course is justified and directs AEMO to proceed with an uprated scope for the project.

Due to the assessment of the augmented scope, delivery of the WRL is assumed to be completed in mid-2027 rather than its original mid-2026 completion date.

The updated proposed scope of the Western Renewables Link as described within the 2023 NEVA order consists of:

- A new 500/220 kV terminal station near Bulgana with two new 1,000 MVA 500/220 kV transformers.
- New 500 kV double circuit transmission lines from Sydenham to a new terminal station near Bulgana
- The original scope to turn one of the existing Ballarat to Moorabool 220kV transmission lines into the existing Elaine Terminal Station has been maintained as part of this project..



AusNet Services is progressing planning and environmental investigations within the project's identified corridor and is currently engaging with identified landowners and key representatives of the community. The latest project information is available on AusNet Services' dedicated project website[64].

VNI West

VNI West is a proposed new high capacity 500 kV double circuit overhead transmission line, which will deliver vital new transmission infrastructure to:

- Carry clean, low-cost renewable power from REZs in New South Wales and Victoria, in particular the wind and solar-rich regions of the Murray River REZ and the Western Victoria REZ.
- Harness upwards of 3.4 GW of new renewable generation in the Murray River and Western Victoria REZs.

[63] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/PACR/Western-Victoria-RIT-T-PACR.pdf.

[64] See https://www.westernrenewableslink.com.au.

- Add 1.93 GW of electricity export capacity from Victoria to New South Wales, and 1.67 GW of electricity import capacity from New South Wales to Victoria.
- Improve security and reliability in the electricity network as coal-fired power stations retire.

In May 2023, AVP and Transgrid released the Project Assessment Conclusions Report[65] (PACR) which identifies the preferred network option for VNI West. The PACR is the final report in the RIT-T. The PACR identifies the preferred option for VNI West, charting a broad corridor that connects it to WRL at a new terminal station at Bulgana and crossing the Murray River north of Kerang. This continues on to EnergyConnect in New South Wales at the new Dinawan substation. It is known as Option 5A.

A new AEMO company, Transmission Company Victoria (TCV) has been established to undertake early works in Victoria, including community, landholder and Traditional Owner consultations and ongoing investigations into the corridor and ultimate route. The Draft Corridor Report[66], published 6 October 2023, highlights a draft corridor for the line approximately 2 km wide for Victoria. VNI West is planned for ‘first energisation’ in 2028, and fully operational (with inter-network testing complete, subject to market conditions) in Q4 2029.

VNI West consists of:

- A new 500 kV double circuit overhead line from Bulgana to near Kerang to locality of Dinawan, including series compensation on the line near Kerang.
- Construction of the Dinawan to near Wagga Wagga line as a double circuit 500 kV line, rather than a double circuit 330 kV line and later uprate from 330 kV to 500 kV operation (including new 500 kV bays and a transformer station near Wagga Wagga).
- Establish Dinawan 500 kV switchyard with two 500/330 kV 1,500 MVA transformers.
- Establish new terminal station near Kerang with two 500/220 kV 1,000 MVA transformers.
- 220 kV connections from the new terminal station near Kerang to the existing 220 kV lines near Kerang.
- Modular power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang and 220 kV lines between Dederang and Thomastown following certain contingencies.
- 500 kV line shunt reactors at both ends of the three following 500 kV circuits: (i) Bulgana – near Kerang, (ii) near Kerang – Dinawan and (iii) Dinawan – near Wagga Wagga.
- Up to +/- 400 MVAr dynamic reactive compensation at the new 220 kV terminal station near Kerang.
- In addition, series compensation or additional power flow controllers would be installed along the Kerang to Bulgana section to reduce impedance on the new 500 kV network.

Committed control scheme upgrade projects

The following control scheme upgrades have been committed or planned by AVP for implementation in the DSN.

- **Interconnector Emergency Control Scheme (IECS)** – the existing IECS is used to minimise supply disruption following non-credible contingencies of multiple 330kV and 220kV transmission lines between Murray and Thomastown terminal stations, by quickly shedding load or tripping generation, to reduce the probability of Victoria separating from New South Wales which could trigger large scale of load shedding.

[65] See https://aemo.com.au/initiatives/major-programs/vni-west/reports-and-project-updates.

[66] See https://www.transmissionvictoria.com.au/-/media/16bf3d579a8944f084eb37bd800a13a0.ashx?la=en.

  - Due to the increased penetration of rooftop PV generation, existing load shedding blocks have experienced a decline in prospective load to be shed. In this project, the existing IECS will be modified to include additional load blocks to the load shedding sequence, to maintain system security in Victoria.

- **Murraylink Very Fast Run Back Control Scheme (ML VFRB)** – this existing ML VFRB is used to manage line loading and voltage stability by quickly running back Murraylink export to South Australia post contingency. EnergyConnect Stage 1 includes the connection of a new double circuit line in Red Cliffs Terminal Station, replacing the existing single circuit line between Buronga and Red Cliffs. This update will include the new double circuits as one of the monitored contingency to trigger the VFRB should all triggering conditions be met.
- **South West Victoria Generation Fast Tripping (SWVic GFT) Control Scheme** – this existing SWVic GFT control scheme was designed to fast trip a number of large wind farms connected to the 500 kV network in the South West Victoria area following non-credible contingencies, to avoid power system oscillation due to lack of system strength. The upgrade will modify the triggering condition of this control scheme, to minimise impact on generators.

4.2 Neighbouring TNSP projects

EnergyConnect

EnergyConnect is a committed interconnector between South Australia and New South Wales, with connection to Victoria at Red Cliffs, with a transfer capacity of 800 MW. The project is aimed at reducing the cost of providing secure and reliable electricity across the NEM, while facilitating a longer-term transition to low emission energy sources in Northern South Australia and Southern New South Wales. The completion of Energy Connect will provide increased transfer capacity between Victoria and New South Wales via the upgraded Red Cliffs to Buronga 220 kV connection. The project reached Considered status in March 2023, meaning that new connections enquiries can now be formally lodged and processed.

EnergyConnect consists of:

- Stage 1 – a new 275 kV and 330 kV double circuit interconnector from Robertstown in mid-north South Australia to Buronga in south-west New South Wales, via a new 275/330 kV substation at Bundey, South Australia. The scope for Stage 1 includes a new 220 kV double circuit line between Buronga and Red Cliffs in Victoria, which replaces the existing single circuit line. Commissioning of Stage 1 will take place in early 2024 with release of the initial power transfer planned for mid-2024.
- Stage 2 – a new 330 kV double circuit transmission line (540 km) between Buronga and Wagga Wagga in New South Wales, construction of a new substation at Dinawan, and an upgrade of the existing substation at Wagga Wagga. The section between Dinawan and Wagga Wagga will be constructed to 500 kV and operated at 330 kV in anticipation of the VNI West project connecting at Dinawan Terminal Station in New South Wales. Stage 2 is expected to be completed in July 2026.

Marinus Link

Marinus Link is a proposed underground and undersea electricity transmission project, comprising two cables, to further link Tasmania and Victoria. The first stage of the project (first cable), delivering a 750 MW high voltage direct current (HVDC) link, is being prioritised whilst negotiations continue for the second stage. The project includes new terminal stations and other necessary augmentations in Tasmania and Victoria.

This project will provide improved access to Tasmania's dispatchable capacity (including deep storages) and high quality VRE opportunities, helping reduce the scale of investment needed on the mainland. Wind farms located in Tasmania (particularly Tasmania's Central Highlands and North-West REZs) produce more energy than almost all REZs on the mainland, and provide greater resource diversity to mainland wind farms. Without improved access to these resources, more mainland capacity would be required for the equivalent volume of energy, which would increase system costs, all else being equal[67].

Marinus Link is proceeding with the early works required to be able to achieve a Final Investment Decision (FID) expected by the end of 2024, enabling commissioning of the first cable in 2029-30.

HumeLink

HumeLink is an actionable ISP project to reinforce the southern New South Wales network with a new 500 kV transmission line between Maragle, Wagga Wagga and Bannaby[68], which links greater Sydney load centre with South Australia and Victoria through EnergyConnect , and unlocks the full capacity of Snowy 2.0[69]. AEMO's August 2023 NEM Transmission Augmentation Information indicates an in-service date for HumeLink of July 2026[70].

4.3 New terminal station developments to support connections

A new 500 kV Cressy Terminal Station will be developed as the connection point to the newly committed Golden Plains Wind Farm (Stage 1 – 730 MW), and is expected to be operational in late 2024.

A new 220 kV Gnarwarre Terminal Station will be developed as the connection point to the newly committed Gnarwarre BESS, and is expected to be operational in early 2025.

[67] See https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

[68] See TransGrid's 2022 TAPR, at https://www.transgrid.com.au/media/jn4klv4s/tgr12164-tapr-2022-v5-4-final.pdf.

[69] See HumeLink Project Assessment Conclusion Report (PACR), at https://www.transgrid.com.au/media/rxancvmx/transgrid-humelink-pacr.pdf.

[70] See 2023 Transgrid Annual Planning Report at https://www.transgrid.com.au/tapr.

5 Annual Planning Review and Transmission Development Plan for Victoria

This section explores potential new limitations that may impact supply reliability, reduce system performance, impact efficient asset utilisation, or result in additional network constraints, and updates AVP's plan for developing the Victorian network. Where options to address limitations are likely to exceed the AER's RIT-T cost threshold determination[71] and deliver benefits to consumers, RIT-Ts will be triggered in future.

Key outcomes of the Annual Planning Review

- New switching arrangements have been identified to better balance the loading on the Latrobe Valley to Melbourne 220 kV lines and the 500/220 kV transformers at Rowville and Cranbourne, to improve network utilisation following the retirement of Yallourn Power Station.
- Increased maximum demand forecasts in the 2023 IASR are driving new emerging limitations on the DSN, where further network investment may now be beneficial for consumers. Specifically:
  - Small scale options to address thermal limitations on the Moorabool – Geelong 220 kV lines now warrant further investigation due to increasing wind and BESS capacity in Western and Southwestern Victoria as well as forecast demand growth.
  - Maximum demand forecasts in Melbourne metropolitan area are driving an expected increase in thermal limitations on the Thomastown – Ringwood 220 kV line and Rowville A1 500/220 kV transformer. In addition to the newly identified switching arrangements in the Latrobe Valley, network investment is likely to be required in next decade to support this forecast load growth.
- As many of these emerging limitations are in a strongly meshed part of the network, a holistic approach is needed to identify the most economically efficient way to address these multiple inter-related limitations under future conditions.
- AVP will commence power system analysis and economic assessment of options for Eastern Metro and Western Metro Reinforcement to identify credible network and non-network options to jointly address a number of emerging limitations identified in this VAPR. This may trigger RIT-Ts, commencing prior to the 2024 VAPR.
- System Strength and Metropolitan Melbourne Voltage Management RIT-Ts have both published Project Specification Consultation Reports (PSCRs) to address emerging limitations identified in the 2022 VAPR and in AEMO's 2022 *System Strength Report*.

AVP's Transmission Development Plan for Victoria addresses limitations identified in the Annual Planning Review, and is designed to meet security and reliability objectives in an efficient way over the coming decade. This means it is not necessarily designed to remove all network congestion – particularly where generation

[71] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/cost-thresholds-review-for-the-regulatory-investment-tests-2021.

investments occur in weaker parts of the grid or where the costs of augmentation outweigh the benefits to consumers.

AVP proactively identifies and monitors future limitations through its operational, planning, and connection functions, which could trigger further study under specific system changes or generator investment patterns.

The VAPR provides an opportunity to build on these investigations, and undertake a full review of the Victorian DSN in accordance with the requirements of NER 5.12.1. The VAPR uses detailed analysis to capture the nature, timing, impact, and triggers associated with potential limitations, which identify the need for RIT-Ts and also inform the subsequent ISP. The focus of this work is on identifying projects that are likely to deliver net positive economic benefits under the current regulatory framework, or where corrective action is required to keep the DSN reliable and secure.

5.1 Methodology

The VAPR identifies opportunities to address transmission network limitations emerging over the next 10 years, where credible solutions are likely to deliver positive net market benefits. The overall planning approach is described below, and the identified limitations are discussed in the following sections.

Note that the numbering of the limitations in this section does not reflect the ranking of most significant Victorian transmission constraints observed in 2022-23, shown earlier in Figure 16. They relate to future limitations that are forecast over the next decade that may ultimately require network augmentation to address (shown below in **Figure 20**).

5.1.1 DSN augmentation planning approach

To identify network augmentation needs, AVP first investigates transmission network limitations by:

- Reviewing historical network performance over the previous year, noting that past performance is becoming a weaker indicator of future performance as the demands on the DSN change (see Section 3).
- Reviewing future network performance under a range of demand and generation scenarios considering government policy and economic growth projections described in Section 2 and Section 4, through exploratory studies in this section.

For the purposes of the VAPR, a limitation is defined as a network element or location that, in the next 10 years:

- Is forecast to be loaded to 90% of its continuous rating, or experience voltages outside its normal voltage range, during system normal operating conditions.
- Is forecast to be loaded to 90% of its short-term rating, or experience voltages outside its contingency voltage range, following a contingency event.
- Does not maintain the minimum three phase fault level or stable voltage waveform system strength standard for that location as determined under by AEMO under 5.20C.1 of the NER.
- Has voltage unbalance levels which do not meet the requirements outlined in S5.1a.7 of the NER.

- Has typical inertia dispatched being less than the secure operating level of inertia, where the typical inertia is the value at one standard deviation below the mean and the secure operating level of inertia is the minimum level of inertia required to operate an islanded inertia sub-network in a secure operating state[72].
- Does not maintain sufficient reactive margins following a credible contingency event as outlined in S5.1.8 of the NER.
- Does not meet the requirements for steady-state magnitude of power frequency voltage outlined in S5.1.4 of the NER.
- Has a fault level shortfall as outlined in Clause 11.143.14 of the NER.
- Has a heavily restricted outage window due to other constraints and limitations.

Exploratory studies, which mainly include screening and trigger studies, are carried out to identify DSN thermal and voltage control limitations that may emerge over the next 10 years. Screening studies are used to identify expected limitations, while trigger studies are used to test the system under more extreme scenarios to identify conditions that trigger further limitations.

The VAPR analysis always incorporates a full set of state-wide screening studies, and specific trigger studies are undertaken if necessary, to examine the triggers likely to cause transmission network limitations beyond the current 10-year forecasts of generation, demand, or other planning inputs.

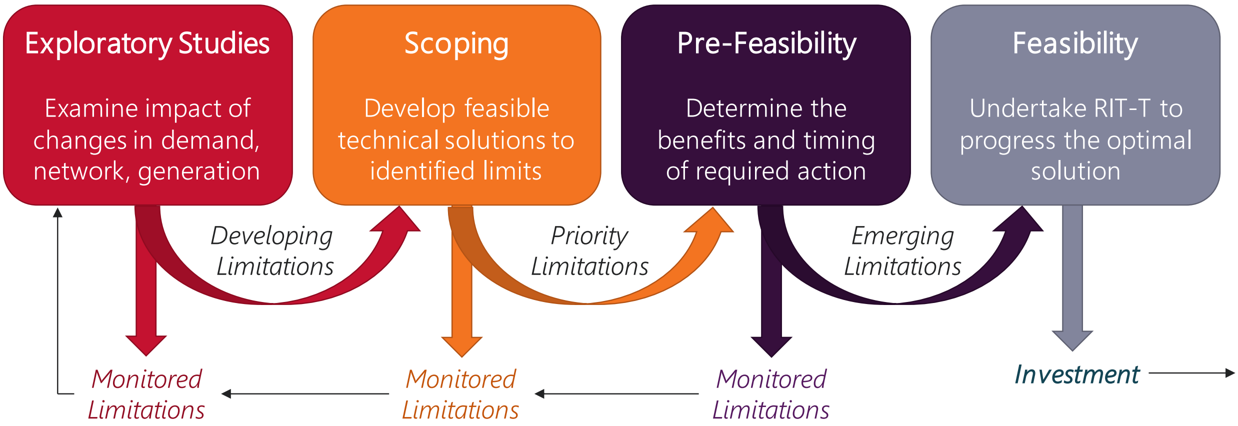
Screening studies identify limitations by assessing network performance in terms of security and performance obligations under a range of different power system configurations. Security and performance obligations define the transmission system's technical limitations (for example, voltage ranges, thermal limits, stability limits, maximum fault currents, and fault clearance requirements). These obligations ensure that connected assets (and the power system itself) are designed to operate within known technical limits.

For each network element, screening studies are typically undertaken for a base case and a worst-case scenario, in order to capture a wide range of limitations. The worst-case scenario differs, depending on the transmission network element under consideration, and is a variation on the base case scenario designed to test that specific network element. For example, in a particular location the worst-case scenario may be 100% VRE output, while in another location the worst case may be 0% VRE.

AVP identifies possible options to address the identified limitations, then estimates the costs of the options, and assesses the likelihood of these delivering positive net market benefits (where applicable). Based on these assessments, the limitations are categorised as shown in **Figure 19**, and described below.

[72] For more information see *Inertia Requirements Methodology Inertia Requirements and Shortfalls*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

Figure 19 Identification of network limitations – the planning cycle



Limitations are categorised as:

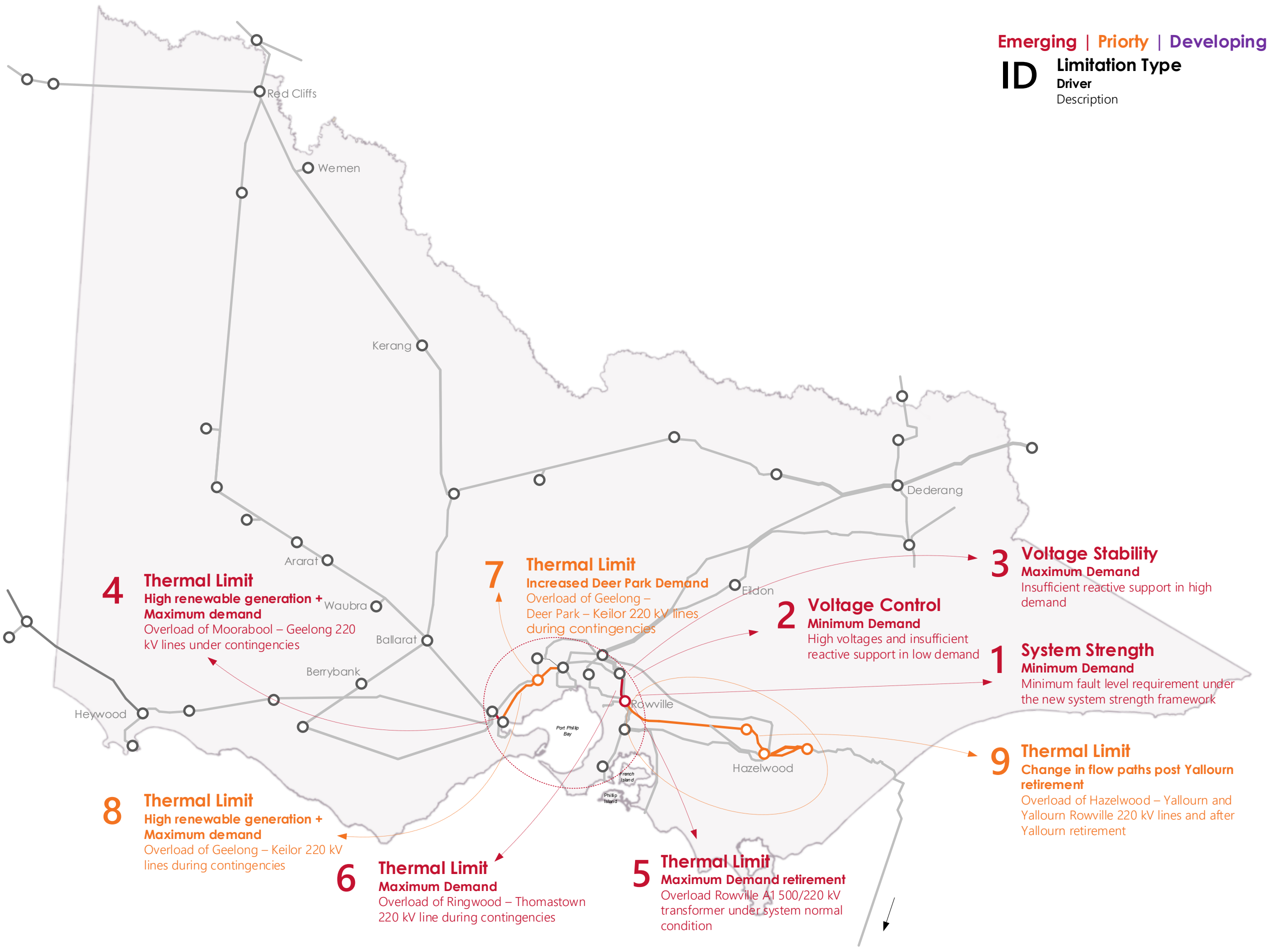
- **Emerging limitations** – limitations for which credible solutions are likely to deliver positive net market benefits. AVP will begin a RIT-T (or other relevant regulatory approval process) within 12 months to identify the optimal solution and investment timing.
- **Priority limitations** – limitations for which credible solutions may deliver positive net market benefits. Following the VAPR publication, AVP will undertake further pre-feasibility assessment using more detailed market modelling to assess the benefits from credible augmentation options.
- **Monitored limitations** – limitations for which there is currently no credible solution likely to deliver positive net market benefits. AVP reassesses these limitations annually, when conditions change, or when a new credible solution becomes available.
- **Developing limitations** – a subset of monitored limitations, for which credible solutions likely to deliver positive net market benefits may be identified or confirmed before the next VAPR cycle, or triggering conditions are more likely to change rapidly and therefore require heightened active monitoring or further pre-feasibility assessment within 12 months. These may include limitations in areas of high investor interest, those related to step changes in supply or demand, or those which have occurred operationally under unusual system conditions.

AVP normally performs high-level economic assessments in determining emerging limitations, and may perform these assessments for priority limitations when required. This analysis and categorisation can provide signals for potential non-network development opportunities, such as localised generation or demand response.

AVP undertakes joint planning with AEMO as national planner (ISP process), other TNSPs and Victorian DNSPs to address transmission limitations, challenges, and opportunities. Victorian joint planning outcomes have been incorporated into the limitation summaries presented in this section.

Figure 20 shows the limitations under investigation in this Annual Planning Review, assuming the network developments already progressing and discussed in Section 4 proceed. A complete list of the identified emerging, priority, developing, and monitored transmission network limitations is given in Appendix A4. Appendix A3 has more information on AVP's approach to transmission network limitation reviews.

Figure 20 Emerging, priority and developing limitations under investigation



5.2 Emerging limitations

5.2.1 Emerging limitations identified in 2022 VAPR

The following emerging network limitations were identified in the 2022 VAPR and have now commenced RIT-Ts in 2023. **Table 10** summarises progress of AVP's analysis for these limitations, with further detail on the relevant RIT-Ts provided below.

Table 10 Emerging limitations from 2022 VAPR

#	Limitation (conditions)	Description	Status/Next steps
1	**Maintaining system strength requirements under the new System Strength Framework.**	Under the new System Strength framework, AVP must make available sufficient services available to maintain the minimum fault level and a stable voltage waveform for Victoria at all times.	Options to meet the system strength standard under the new framework from 2 December 2025 onwards are being assessed through a RIT-T. A PSCR report and RFI seeking information on non-network options were both published in July 2023[A]. AVP will commence analysis for the PADR stage of the RIT-T following closure of the PSCR consultation period on 6 October 2023.
2	**High voltages in Metropolitan Melbourne and South West Victoria**	Options to provide reactive support during forecast	A PSCR report was published in October 2023[B].

#	Limitation (conditions)	Description	Status/Next steps
	(caused by low and negative demand conditions forecast in the 2022 ESOO over the next decade).	maximum and minimum demand conditions.	AVP will commence analysis for the PADR stage of the RIT-T following closure of the PSCR consultation period on 31 January 2024.
3	**Metropolitan Melbourne area voltage stability** (caused by aging capacitor banks and high demand conditions forecast in the 2022 ESOO over the next decade).		

A. Victorian System Strength Requirement PSCR, at https://aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength---project-specification-consultation-report_final.pdf?la=en.
B. See https://aemo.com.au/initiatives/major-programs/metropolitan-melbourne-voltage-management-regulatory-investment-test-for-transmission

System Strength RIT-T (Limitation #1)

Under the new System Strength framework which came into effect on 2 December 2022, AVP is responsible for proactive provision of system strength services, as the System Strength Service Provider (SSSP) for Victoria, to ensure power system stability and to facilitate efficient generator and storage connections as set out in the 10-year forecast provided in the most recent *System Strength Report*[73].

AVP is undertaking a RIT-T to procure system strength services to meet the system strength standard as set in AEMO's 2022 System Strength Report, and has published a PSCR and Request for Information (RFI)[74] outlining the identified need and potential credible options to address the need. AVP will need to procure sufficient system strength services to meet both the minimum three-phase fault level requirement and efficient level as shown in **Table 11** and **Table 12** respectively.

Table 11 Victorian minimum three phase fault level requirement (MVA)

System strength node and voltage	Pre-contingency fault level requirement (MVA)	Post-contingency fault level requirement (MVA)
Dederang 220 kV	3,500	3,300
Hazelwood 500 kV	7,700	7,150
Moorabool 220 kV	4,600	4,050
Red Cliffs 220 kV	1,786	1,036
Thomastown 220 kV	4,700	4,500

Note: as specified in Table 36, AEMO, 2022 *System Strength Report*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-system-strength-report.pdf?la=en.

Table 12 AEMO 2022 *System Strength Report*– modified forecast IBR generation (MW)

System strength node	2025	2026	2027	2028	2029	2030	2031	2032	2033
Moorabool	0	0	0	0	0	56	847	1,359	1,459
Hazelwood	374	394	394	394	833	1,482	2,001	2,001	2,001
Dederang	0	0	0	0	0	0	0	264	264
Red Cliffs	0	0	0	0	0	0	0	354	1,437
Thomastown	0	0	0	0	0	0	0	0	0

Note: As specified in Table 39, AEMO, 2022 *System Strength Report*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-system-strength-report.pdf?la=en. This table has been modified from the forecast published in the 2022 *System Strength Report*, with recent generation commitment (Hawkesdale Wind Farm) subtracted from the relevant system strength node and technology type.

[73] AEMO, 2022 *System Strength Report*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-system-strength-report.pdf?la=en.

[74] AEMO, Victorian System Strength RIT-T, at https://aemo.com.au/en/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission.

AEMO, in the 2022 *System Strength Report*, completed wide-area electromagnetic transient (EMT) studies in Victoria which indicated that the power system stability may be maintained under lower minimum fault levels. The minimum fault level requirement for Victoria may be decreased in future years following confirmation from AVP as SSSP for Victoria that both protection system operation and the stable operation of voltage control devices can be maintained at lower fault levels. AVP is currently investigating the fault level requirements for protection system operation, and fault level requirements for stable operation of voltage control devices.

AVP has identified in the Victorian System Strength Requirements PSCR[75] that the equivalent network solution of synchronous condensers to meet the system strength standard is as shown in **Table 13**.

Table 13 Equivalent network solution to meet the system strength standard

System strength node	Equivalent network solution	Timing
Hazelwood	5 x 250 MVAr synchronous condensers	From December 2025 ongoing, to meet the minimum fault level
Moorabool	1 x 250 MVAr synchronous condenser	From December 2025 ongoing, to meet the minimum fault level
	2 x additional 250 MVAr synchronous condensers	From 2030 ongoing, to maintain stable voltage waveform
Red Cliffs	1 x 125 MVAr synchronous condenser	From December 2025 to the commissioning of Energy Connect Stage 2 (July 2026), to meet the minimum fault level
	1 x 250 MVAr synchronous condenser	From 2032[A] ongoing, to maintain stable voltage waveform

A. Timing is expected to align with Victoria – New South Wales Interconnector West (VNI West).

The size and location of the synchronous condensers are intended to be a guide for any equivalent non-network options.

As well as being critical in meeting the system strength standard in the short term (given the timing constraints for network solutions noted above), AVP expects non-network options to continue to be a major contributor in meeting the long-term system strength requirements beyond 2025.

Non-network options can be (but are not limited to) procurement of system strength services from:

- Synchronous machines.
- Modification to existing synchronous generators.
- Grid-forming batteries, generators, static VAR compensators (SVCs) and STATCOMs.

The second stage of the RIT-T process is a full options analysis, followed by publication of a Project Assessment Draft Report (PADR) in accordance with clause 5.16.4 of the NER. The recommended preferred option may be a combination of network and non-network options. The third and final stage of the RIT-T process, the Project Assessment Conclusions Report (PACR), will make a conclusion on the preferred option.

Metropolitan Melbourne Voltage Management RIT-T (Limitations #2 and #3))[76]

Over the coming decade, maximum electricity demand in Victoria is forecast to continue growing, while minimum electricity demand is forecast to continue decreasing. In addition, aging equipment that supplies reactive power during maximum demand is approaching retirement. Together, these trends are driving a need for investment to

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

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

maintain transmission system voltages within operational and design limits during both high and low demand periods.

In October 2023, AVP published a PSCR outlining credible network options and characteristics required for non-network options. As well as limitations #2 and #3, this RIT-T also addresses the reactive power limitation identified in the 2022 VAPR at Deer Park Terminal Station to prevent under-voltages at maximum demand times.

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 National Electricity Rules (NER). The third and final stage of the RIT-T process, the Project Assessment Conclusions Report (PACR), will make a conclusion on the preferred option.

5.2.2 New emerging limitations identified in 2023

AVP has conducted a combination of power flow modelling and economic assessments to identify new network limitations, following the methodology described in Section 5.1. These studies include all planned developments listed in Section 4.

Three new emerging limitations have been identified by AVP this year as described in **Table 14**, and AVP will now commence pre-feasibility assessments, including RIT-Ts if necessary, to identify the preferred option to address these limitations in 2024. These emerging limitations and proposed studies are discussed in the following sections.

Table 14 New emerging limitations from 2023 VAPR

#	Limitation (conditions)	Category		Description and next steps
		2022	2023	
4	**Overloading of the Moorabool – Geelong 220 kV lines for trip of the parallel line (due to high generation in South West Victoria and Western Victoria as well as high demand in Greater Melbourne)**	Developing	Emerging	The impact of this limitation has increased in the 2023 VAPR due to commitment of additional generation and BESS in V4 South West Victoria, coupled with higher demand growth in the metropolitan area and generation retirement in Latrobe Valley. AVP will commence the pre-feasibility studies to assess options to address this limitation, including a RIT-T if necessary, prior to the next VAPR. The pre-feasibility studies will form part of the Western Metro area configuration assessment, which is detailed in Section 5.9.1.
5	**Overloading of the Rowville A1 500/220 kV transformer during system normal (due to high demand in Greater Melbourne)**	Developing	Emerging	The impact of this limitation has increased in the 2023 VAPR due primarily to higher demand growth in the Melbourne metropolitan area, which is further exacerbated by retirement of Yallourn power station. AVP has identified a new switching arrangement at Hazelwood Power Station (modified parallel mode) for post YPS retirement, which will balance the loading on the Latrobe Valley to Metropolitan Melbourne 220 kV lines and the 500/220 kV transformers at Rowville and Cranbourne, as detailed in Section 5.3.1. However, the modified parallel mode will not be sufficient in managing this limitation in the long term given the increasing demand forecast. AVP will commence holistic pre-feasibility studies, including a RIT-T if necessary, for the Eastern metro area after the VAPR publication to assess potential reconfiguration or augmentation options. The holistic studies will cover not only this limitation, but also emerging limitation #6 described below, taking into account other factors affecting this area, including maximum fault levels, upcoming asset retirements and anticipated network developments.
6	**Overloading of Thomastown – Ringwood 220 kV line for loss of the Rowville A1 transformer (due to high demand in Greater Melbourne)**	Monitored	Emerging	Similar to #5 limitation described above, the impact of this limitation has increased in the 2023 VAPR due primarily to increased maximum demand forecasts in Melbourne metropolitan area. The holistic feasibility studies for the Eastern metro area will also address this limitation as described above.

Moorabool – Geelong thermal limitation (limitation #4)

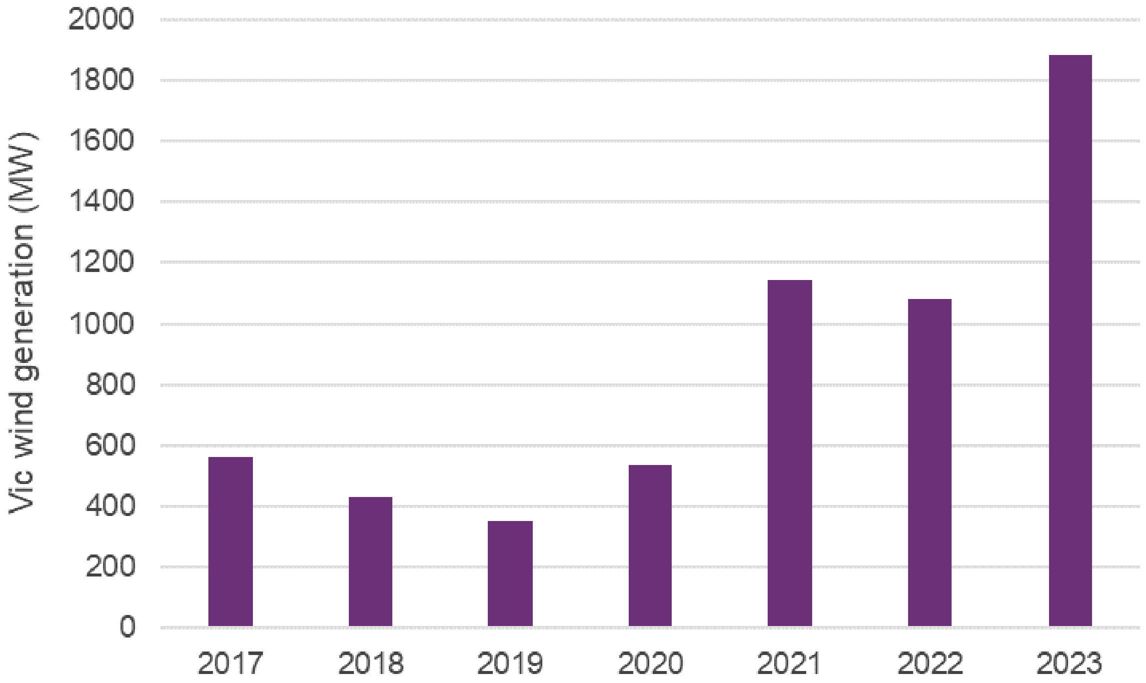
Thermal loading on the Moorabool – Geelong corridor was identified as a developing limitation in the 2022 VAPR. Since then, AVP has determined that credible solutions to address this limitation are likely to provide positive net market benefits due to commitment of additional wind generation in V4 South West Victoria, Yallourn retirement and higher projected maximum demands in the 2023 IASR, making this an emerging limitation.

Thermal loading on the Moorabool – Geelong – Keilor corridor was presented as a single limitation in the 2022 VAPR as they are geographically close and have similar drivers. The Moorabool – Geelong and Geelong – Keilor lines have been decoupled in 2023 due to differences in the expected timing, critical contingencies, and likely solutions for each. Thermal loading on the Geelong – Keilor lines is a priority limitation in 2023 (see Section 5.3.3 for more detail).

The Moorabool – Geelong thermal limitation arises when there is high wind generation in the V3 Western Victoria and V4 South West Victoria REZs during high Victorian demand. This may occur both from high wind generation during typical daily peak demand, and from moderate or greater wind generation during annual maximum summer demand when hot temperatures reduce the rating of the lines. While both cases result in Moorabool – Geelong being loaded close to its rating, the latter case presents the greater challenge as constraints on generation to manage this limitation are more likely to result in reserve shortfalls during high summer demand periods.

The contribution of wind generation to annual peak demand has steadily increased in recent years due to Victoria's growing wind capacity. As a result, the power flowing through the Moorabool – Geelong lines during peak demand has increased. **Figure 21** below shows the increase over time of wind generation during annual peak demand.

Figure 21 Victorian wind generation during annual peak demand, 2017 to 2023



Source: AEMO OPDMS data.

WRL will help alleviate this limitation by creating a new, separate path for wind generation to supply the Western Metro load area. Shortly after however, retirement of Yallourn Power station will exacerbate this limitation by increasing Victoria's reliance on generation from the V3 Western Victoria and V4 South-West Victoria REZs during peak demand. AVP anticipates that WRL itself will not completely address this limitation as additional generation in the V3 Western Victoria and V4 South-West REZs continues to connect.

AVP is considering options to manage thermal loading on Moorabool – Geelong for loss of the parallel line. These options may include, but not be limited to:

- Alternative operational arrangements to reduce power flow on the remaining line following a loss of a Moorabool – Geelong line.
- Replacement of station limiting plant to increase the rating of both Moorabool – Geelong lines.
- Installation of wind monitoring on the Moorabool – Geelong lines to allow operation at higher ratings during periods of high wind-driven V3 and V4 generation.

AVP will also commence a holistic assessment of the Western Metro area network to determine the optimal configuration which maximises the utilisation of existing assets while taking into account other factors which could affect this area, including maximum fault level issues, upcoming asset retirements and anticipated network developments. More detail is provided in Section 5.9.1.

Rowville A1 500/220 kV transformer thermal limitation (limitation #5)

The Rowville A1 transformer supplies a number of Eastern metro connection points including Ringwood, Thomastown, Springvale and Malvern. The loading on the A1 transformer is forecast to exceed its continuous rating under system normal condition due primarily to higher demand growth in the Melbourne metropolitan area, further exacerbated by retirement of Yallourn Power Station.

The new switching arrangement proposed by AVP for Latrobe Valley for post-retirement of Yallourn, as described in Section 5.3.1, will help reduce the overloading in A1 transformer to some extent. Nevertheless, due to the higher demand forecast projected for Victoria in 2023 IASR and with most of the demand located in the metropolitan area, the loading level of the A1 transformer under system normal condition is still forecast to exceed its continuous rating during peak demand times.

Based on the 2023 10% POE forecast, overloading can be noted from 2027-28 and gets significantly higher from 2029-30 onwards. Not addressing this limitation in a timely manner may lead to load shedding during high demand times.

Potential options include, but are not limited to, the following network augmentations:

- Installing a second 500/220 kV 1,000 MVA transformer at Cranbourne and cutting in the existing Hazelwood – Rowville No.3 500 kV line at Cranbourne.
- Installing a third 500/220 kV 1,000 MVA transformer at Rowville, plus any fault level mitigation works.
- Establishing a new 500 kV switch yard at Templestowe cutting into the existing South Morang – Rowville No.3 500 kV line and a new 500/220 kV 1,000 MVA transformer at Templestowe terminal station, plus any fault level mitigation works.
- Expanding the existing Ringwood terminal station by establishing a new 500 kV switchyard by cutting into the existing South Morang – Rowville No.3 500 kV line and installing a new 500/220 kV 1,000 MVA transformer at Ringwood terminal station, plus any fault level mitigation works.

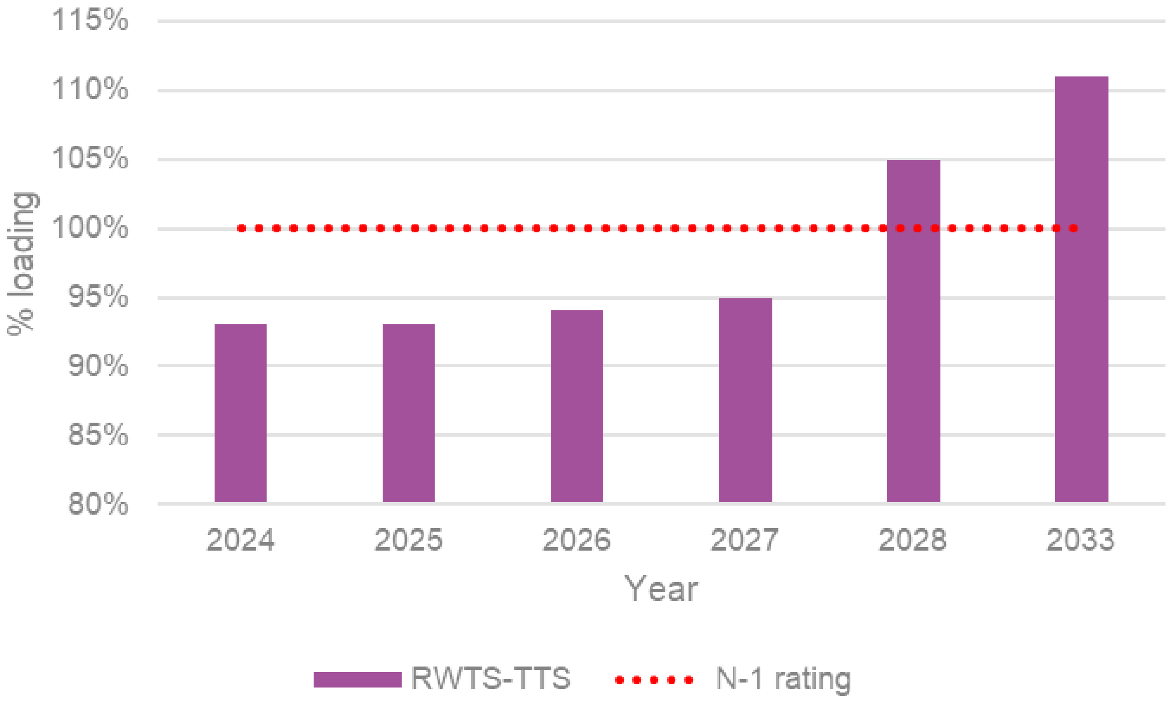
The feasibility of each option needs further investigation, which will be carried out as part of Eastern metro area reinforcement holistic pre-feasibility studies as described in Section 5.9.2. In assessing options to address this limitation, AVP will consider other limiting factors such as fault levels, upcoming asset retirements and anticipated network developments.

Thomastown – Ringwood 220 kV line thermal limitation (limitation #6)

This limitation was identified as a monitored, load-driven limitation in the 2022 VAPR and has been re-assessed this year based on the 2023 IASR demand forecast. The primary driver of this limitation is increasing demand in Eastern metropolitan area, specifically supplied at Ringwood Terminal Station.

During peak demand times from summer 2027-28, the loading of Thomastown – Ringwood 220 kV lines is forecast to exceed its short-term rating for a contingent trip of Rowville A1 500/220 kV transformer. The level of overloading gets exacerbated after the retirement of Yallourn Power Station due to the increased power flow from the west (see **Figure 22**).

Figure 22 Overloading in Thomastown – Ringwood 220 kV line under contingencies



Potential options to manage thermal loading on the Thomastown – Ringwood 220 kV line may include, but are not limited to:

- Upgrading the Thomastown – Ringwood 220 kV line by rebuilding as a double circuit.
- Cutting in Rowville – Ringwood – Thomastown 220 kV at Templestowe and Rowville – Templestowe – Thomastown 220 kV lines at Ringwood to form the Rowville – Ringwood – Templestowe – Thomastown No.1 and No.2 circuits, plus any fault level mitigation work.
- Installing a new (third) 500/220 kV transformer at Rowville, plus any fault level mitigation works.

- Establishing a new 500 kV switch yard at Templestowe cutting into the existing South Morang – Rowville No.3 500 kV line and a new 500/220 kV transformer at Templestowe Terminal Station, plus any fault level mitigation works.
- Establishing a new 500 kV switch yard at Ringwood cutting into the existing South Morang – Rowville No.3 500 kV line and a new 500/220 kV transformer at Ringwood Terminal Station, plus any fault level mitigation works.

The feasibility of each option needs further investigations, which will be carried out as part of Eastern metro re-configuration holistic studies as described in Section 5.9.2.

5.3 Priority limitations

AVP has identified three priority limitations this year for which credible solutions may deliver positive net market benefits in the next 10 years. These priority limitations were identified as developing in the 2022 VAPR and have now progressed to priority due to increased maximum demand forecasts in the 2023 IASR, commitment of additional supply (renewable generation and BESS) in V4 South West Victoria, and anticipated supply changes due to generation retirement in Latrobe Valley. Following the 2023 VAPR, AVP will undertake pre-feasibility assessments, including confirmation of the network limitation and economic assessment of market impacts.

Table 15 New priority limitations

#	Limitation	Category		Description and next steps
		2022	2023	
7	**Thermal capacity limitation - Overloading of the Geelong – Deer Park line for trip of the Deer Park – Keilor line, or the Deer Park – Keilor 220 kV line for trip of the Geelong – Deer Park line (due to increased demand at Deer Park)**	Developing	Priority	AVP will commence holistic pre-feasibility studies following the VAPR to assess the feasible options to improve the thermal capacity in 220kV corridor in the western metro area, which will cover this thermal capacity limitation.
8	**Thermal capacity limitation – overloading Geelong - Keilor 220 kV lines for post credible contingencies (due primarily to increased generation from the southwest area, as well as high demand in Melbourne metropolitan area)**	Developing	Priority	The proposed holistic pre-feasibility studies planned for western metro area will investigate feasible options to relieve this thermal capacity limitation as well.
9	**Thermal capacity limitations in the Latrobe Valley to Melbourne 220 kV corridor-overloading Hazelwood to Yallourn and Rowville to Yallourn 220 kV lines with the modified parallel mode post Yallourn retirement (due to uneven transfer on Latrobe Valley to Melbourne 220 kV corridor)**	Developing	Priority	AVP has identified a new switching arrangement at HWPS (the modified parallel mode), for post-Yallourn retirement to utilise the eastern 220 kV corridor. Although the modified parallel mode will be used to transfer the generation from Latrobe Valley to Melbourne metropolitan area after Yallourn retirement, the 220 kV corridor can still get overloaded during contingencies. AVP will initiate a project following this VAPR to scope out the details of the works required to facilitate the proposed modified parallel in year 2028 to manage the thermal overloads in Latrobe Valley 220 kV corridor.

5.3.1 Latrobe Valley thermal limitations (limitation #9)

The retirement of Yallourn Power Station (YPS) has been announced with all four units (totalling 1,450 MW) to be retired by mid-2028[77]. With this retirement well within the planning horizon, AVP has undertaken studies to determine a range of possible future operating switching arrangements and identify a preferred operating arrangement for Latrobe Valley area.

Currently with YPS in-service the normal operating arrangement is to operate the Latrobe Valley in radial mode as shown in **Figure 23**. This existing arrangement has Hazelwood Power Station (HWTS) buses 1-4 tied together and buses 5-6 tied together separately where a single Yallourn generating unit (YPSW1) is connected to bus group 1-4 with the other units connected to bus group 5-6. This configuration is called radial mode, because generation from YPSW1, together with other generation connected to the 500 kV, will be sent out of the Latrobe Valley radially only through the 500 kV network, while the generation from the remaining three Yallourn units would be delivered to Melbourne through the 220 kV lines between YPS – HWPS – Rowville Terminal Station (ROTS) from a separate radial path. This operating mode has been in place as it offers efficient utilisation of network assets between Latrobe Valley generators and Melbourne load whilst maintaining fault currents within acceptable levels.

Following the retirement of YPS, if changes were not made to the current switching arrangement, the 220 kV network between the Latrobe Valley and Melbourne would be under-utilised, putting additional pressure on other network assets, and deteriorating existing network limitations.

However, fault currents in the area will also reduce which allows for the potential use of many other switching arrangements not currently preferable under system normal conditions. AVP has assessed a range of system normal mode options in detail including permutations of the following options:

- **Parallel mode** – tying all buses at HWPS and operating 550 kV and 220 kV corridors in parallel.
- **Modified parallel mode** – splitting buses at HWPS into two groups to run the MWTS/JLTS and YPS-ROTS networks in parallel (see **Figure 24**).
- **Line out of service** – one or more YPS – ROTS 220 kV lines out of service as hot spares.
- **Transformer out of service** – one HWTS 500 kV/220 kV transformer out of service as a hot spare.

Of the many possible switching arrangements that were assessed, Figure 24 shows the modified parallel switching arrangement, which is AVP's preferred arrangement for the Latrobe Valley considering committed projects and developments. This configuration allows for high utilisation of the existing 220 kV lines while minimising impact on both fault currents and existing generators. It is worth noting that the preferred switching arrangement may vary with future network changes which are not identified or committed at present.

Beyond retirement of YPS and with the preferred arrangement for the Latrobe Valley, AVP expects that thermal limitations in the Eastern Metro area during high demand periods will continue to emerge as they are primarily load driven. Higher maximum demand forecasts in the 2023 IASR compared to previous years are expected to exceed the existing capacity of the broader Eastern Metro network towards the end of the decade. AVP will commence a holistic assessment of the Eastern Metro network to determine whether additional investment in this

[77] See https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station/energy-transition#:~:text=Under%20the%20agreement%2C%20EnergyAustralia%20will%20retire%20Yallourn%20in,energy%20in%20Victoria%2C%20before%20Yallourn%20exits%20the%20system.

area is required. This assessment will consider the potential impact of additional anticipated Latrobe Valley supply from the Victorian Government's offshore wind policy and from Marinus Link. More detail is in Section 5.9.2.

Figure 23 Latrobe Valley radial mode (existing normal configuration)

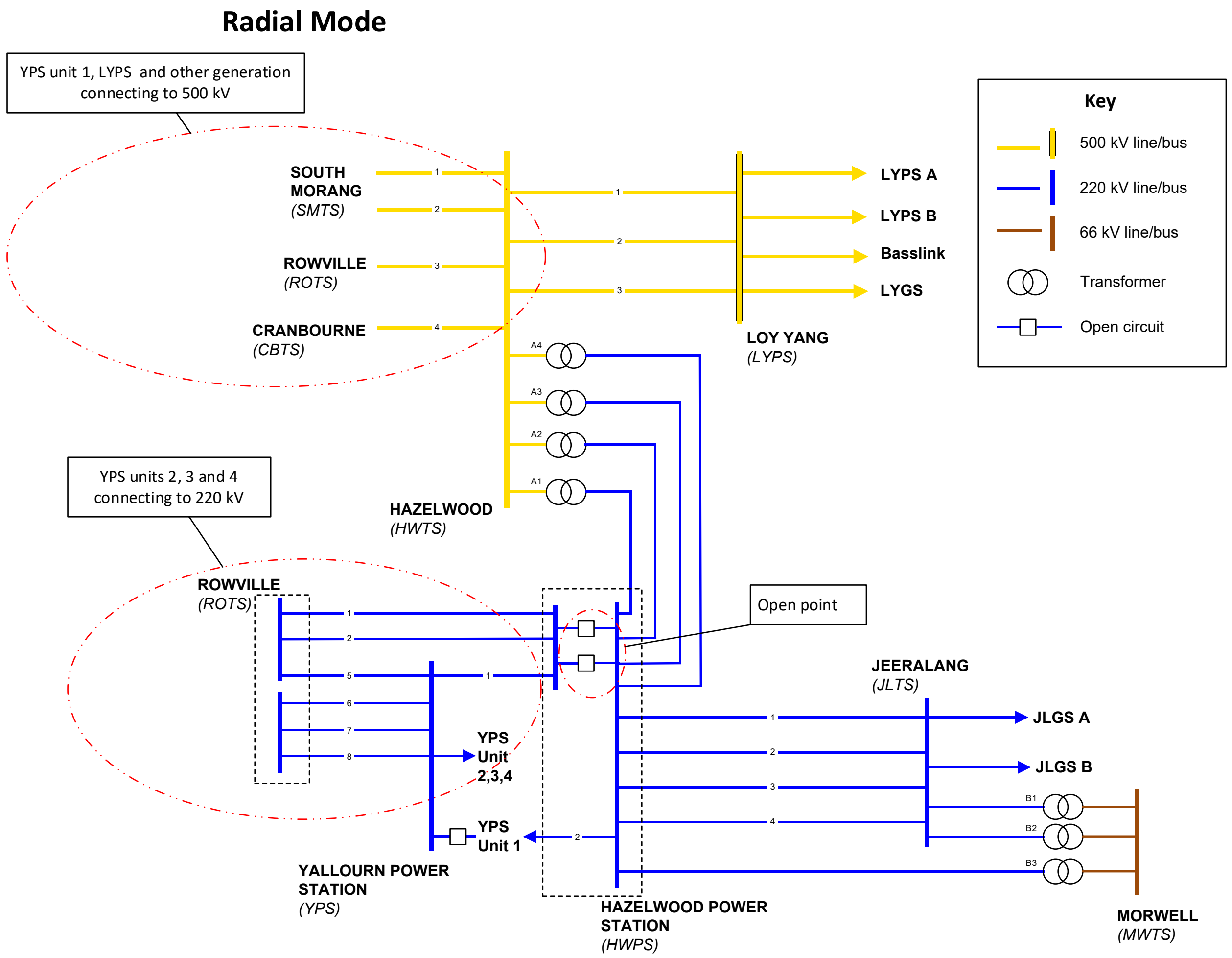
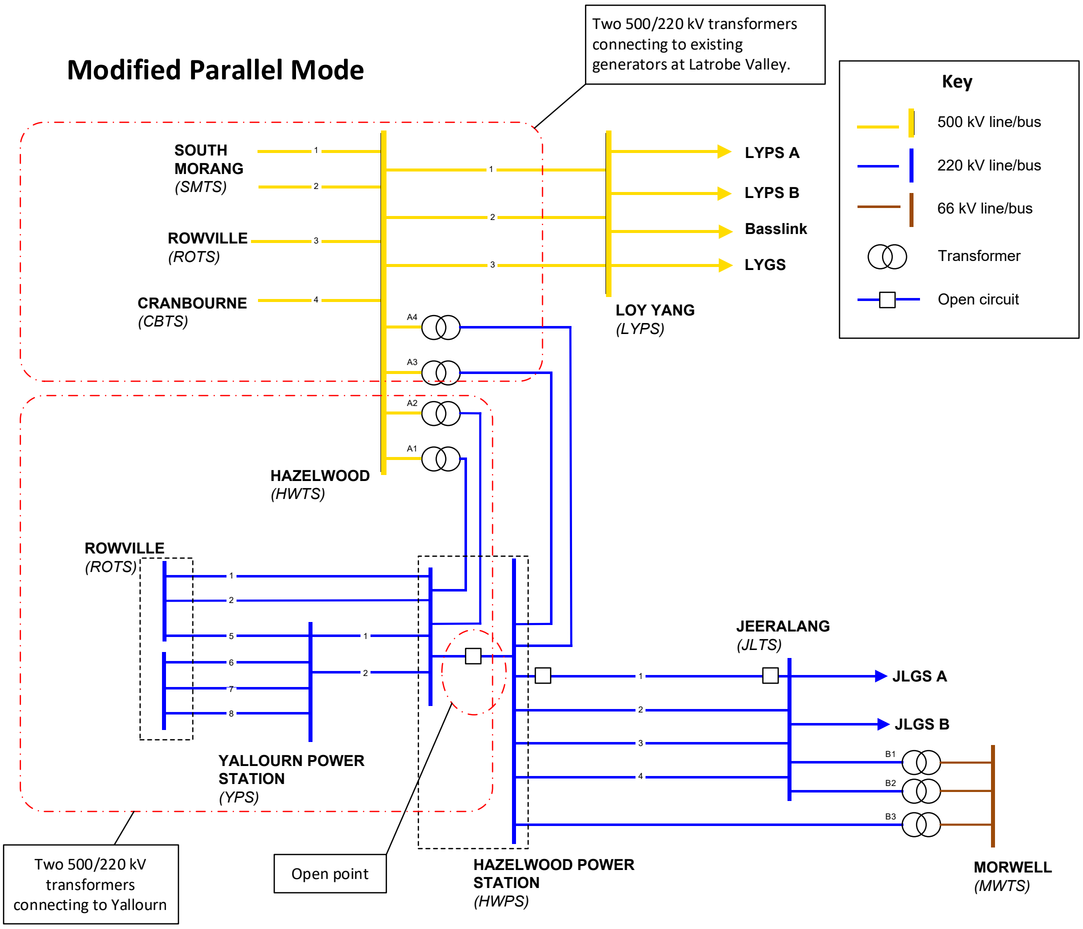


Figure 24 Latrobe Valley modified parallel mode



5.3.2 Deer Park thermal limitation (limitation #7)

Deer Park Terminal Station (DPTS) was established in 2017 to service growing load in the greater Geelong and Western Melbourne area, and is connected to the Victorian transmission network via two 220 kV lines. Previous VAPRs have identified thermal overload of these lines for credible loss of the other line, and low voltage at Deer Park 220 kV for loss of the lower impedance line as developing limitations driven by expected load growth at Deer Park. The Metropolitan Melbourne Voltage Management RIT-T discussed in Section 5.2.1 will address the low voltage issues at Deer Park. The thermal limitation will remain and has progressed to priority in 2023 due to increased demand forecast at Deer Park.

Recently experienced maximum demand levels at Deer Park have reached levels which would approach the thermal capacity of the Geelong – Deer Park or Deer Park – Keilor line for loss of the opposite line under high temperature and low wind conditions.

The latest demand forecasts in the 2022 Transmission Connection Point Report (TCPR) project the maximum load at Deer Park will continue to increase sharply over the coming five years. However, AVP notes that demand forecast is higher than the current n-1 transformer import rating at this terminal station[78]. If this step increase in load were to eventuate, without action to maintain loading on the Geelong – Deer Park – Keilor 220 kV lines

[78] Transmission Connection Point Report, at https://jemena.com.au/documents/electricity/2022-tcpr.aspx.

below their thermal capacity, load shedding would be required. As an operational solution, AVP is working with other NSPs to deliver a post-contingent load shedding control scheme at Deer Park to manage thermal overload of the Geelong – Deer Park – Keilor lines.

AVP will engage in joint planning with Powercor to confirm the impact this may have on the identified limitations at Deer Park.

This limitation will be further assessed by the proposed holistic studies currently planned for the Western metro area, as described in Section 5.9.1.

5.3.3 Geelong – Keilor thermal limitation (limitation #8)

This limitation was identified as a Developing limitation in the 2022 VAPR and has been elevated to a Priority limitation in 2023 due to the increased impact on the western metro 220 kV corridor during high renewable generation from the Southwest (V3 REZ). Without generation redispatch, each of the 220 kV lines between Geelong and Keilor could be overloaded post contingency (for example, loss of Keilor A2 transformer or one of the Geelong-Keilor 220 kV parallel lines), in particular during peak demand times when the generation from the south-west Victoria is high and generation from the east is low post-Yallourn Power Station retirement.

To maintain reliability for Victorian consumers in the next decade, it is vital to relieve DSN congestion so supply from large-scale renewable generation connected in western and south-western Victoria can be sent onto the large loads centres in Melbourne metropolitan area.

High-level options considered by AVP include:

- Uprating the existing Geelong – Keilor 220 kV lines, for example, to 800 MVA at 35ºC.
- Replace the existing Keilor 500/220kV transformers with lower impedance and higher ratings in conjunction with AusNet Services asset replacement program.
- Non-network options, including BESS.

The proposed holistic pre-feasibility assessment for the Western metro area will explore the feasible options to address this thermal limitation in detail and evaluate if they deliver net market benefits.

5.4 Developing limitations

AVP has not identified any new Development limitations in 2023 VAPR.

Five of the seven developing limitations identified in 2022 have been re-categorised based on the 2023 assessment. The limitation associated with insufficient reactive support at Deer Park is being further assessed as part of the recently commenced Metropolitan Melbourne Voltage Management RIT-T. The limitation associated with high rate of change of frequency (ROCOF) in South West Victoria has been removed from the limitation list, because investigation indicates that the impact of this limitation will decrease or even diminish following completion of EnergyConnect.

Refer to Appendix A4 for the updated limitation types and Section 5.2.1 for more details of the Metropolitan Melbourne Voltage Management RIT-T .

5.5 Other monitored transmission network limitations

AVP continues to monitor transmission network limitations that may result in supply interruptions or constrain generation, but for which either there are no currently identified needs/triggers, or there are not yet sufficient market benefits expected to justify the cost of relieving the limitation. The following sections provide more detail on monitored limitations likely to be impacted by new anticipated or committed developments in the DSN announced since the previous VAPR. These developments may include announced generator connections, transmission augmentations, load forecasts, changes in historical constraint behaviour or regulatory changes.

While the monitored limitations reported in this VAPR are identified based on the generation expected closure years, AVP has also carried out a sensitivity analysis to assess the impacts on these limitations due to earlier than announced generator retirements and subsequent supply uptake elsewhere, as included in the 2022 ISP *Step Change* scenario. More information is provided in Appendix A4.

5.5.1 Thermal limitations

The emergence of new thermal limitations, and the benefits of addressing them, are heavily dependent on the geography and intermittency of both supply and demand. Patterns of network flow and asset utilisation continue to change rapidly in Victoria, due to drivers on the supply side such as a strong uptake in VRE projects and decommitment of large synchronous generation, strong uptake of distributed PV. These factors result in a decline of minimum operational demand, and other drivers of maximum demand growth such as projected growth in base load, electric vehicles, and electrification.

In 2022-23, 420 MW of new generation projects connected in Victoria, and new projects continue to be proposed in rural parts of the state, where high-quality solar and wind resources are abundant (see Section 2.3.1). These parts of the network, however, were not originally designed to support such high generation density, and a number of investors have faced economic and technical challenges associated with connecting to these weaker parts of the grid. A number of projects have been and are being delivered to address these challenges (see Section 4). Further projects are likely to be identified through the VTIF, to facilitate development of REZs beyond the 10-year VAPR timeframe.

V4 Ballarat – Terang – Moorabool corridor

In the 2022 VAPR, thermal loading on the Ballarat – Berrybank – Terang – Moorabool lines was reclassified as monitored following completion of a network capability incentive parameter action plan (NCIPAP) project to increase the thermal rating of the lines, and in anticipation of an RDP Stage 1 minor augmentation for a post-contingent generator tripping scheme for generators in this area.

Since the 2022 VAPR, the Australian Renewable Energy Agency (ARENA) announced successful applicants of the Large Scale Battery Storage Funding Round[79] which includes significant additional BESS capacity connecting in Victoria that may influence this limitation. A detailed investigation was conducted to understand the impact of anticipated future generation and storage on this limitation. This investigation confirmed that actions already in place would be sufficient to manage this limitation under anticipated future generation, but also highlighted challenges should additional generation beyond what is already anticipated and committed connect in this corridor.

[79] See https://arena.gov.au/news/arena-backs-eight-grid-scale-batteries-worth-2-7-billion/.

V6 Central North REZ

Thermal loading on the Dederang – Glenrowan – Shepparton – Bendigo 220 kV lines has been identified as a monitored limitation that may be triggered by additional generator connections in the V6 Central North REZ. Since the 2022 VAPR, 100 MW of additional solar capacity has connected in this REZ, with many more applications in the pipeline. Studies found that existing and committed generation has not yet reached levels triggering thermal limitations in this REZ, however highlighted risks if a number of additional generation projects were to connect in the REZ. Minor augmentations under RDP Stage 1 are expected to assist in initially managing these issues. These minor augmentations include a thermal loading control scheme for the Dederang – Bendigo corridor, and transformer secondary cooling upgrade at Dederang (see Table 9, Section 4.1.2).

5.5.2 Stability limitations

V2 Murray River

Voltage stability in the V2 Murray River REZ has ranked highly among the market impact of Victorian network constraints since 2021 when constraints for this limitation were formulated. In the 2022 VAPR, this limitation was re-categorised from priority to monitored due to the expected impact of EnergyConnect and Koorangie BESS (see sections 4.2 and 4.1.2), as well as changes already implemented to the Murraylink VFRS. Since the 2022 VAPR, the Victorian Government announced successful applicants of the VRET 2 auction[80] which includes significant additional solar and BESS capacity in the V2 Murray REZ.

Voltage stability in the V2 Murray REZ was investigated in this 2023 VAPR under anticipated future solar connections. Analysis highlighted a risk that constraints to manage this limitation may have a greater impact if additional solar generation connects prior to commissioning of EnergyConnect, however this risk is significantly mitigated if the anticipated co-located generation and BESS projects are charging during high solar periods. Beyond EnergyConnect, and based on the assumptions used in this Annual Planning Review, additional solar capacity is expected to be able to operate with reduced challenges of voltage stability during periods when market conditions allow the additional export capacity to be utilised.

V4 South West Victoria

The 2020 VAPR reported a developing limitation of voltage collapse in South West Victoria (for a contingency of Moorabool – Haunted Gully line) due to additional generator connections and under high import from South Australia. A constraint was developed in August 2022 to manage this limitation, which has bound for 88 hours in the 2022-23 reporting period, ranking 15th in AVP's constraint impact assessment (see Section 3.5).

As noted in the 2022 VAPR, the RDP Stage 1 project to turn in the existing Haunted Gully – Tarrone line at Mortlake is anticipated to improve voltage stability in South West Victoria. This improvement will be boosted further by establishment of a new terminal station at Cressy to connect stage 1 of the Golden Plains Wind Farm in 2025, which has achieved committed status since the 2022 VAPR. AVP anticipates that these augmentations will be sufficient to prevent significant challenges managing voltage stability during system normal conditions under committed and anticipated future connections to the South West Victoria 500 kV network. Prior to completion of these augmentations in 2025, constraints to address this limitation may temporarily bind more frequently due to recent commitment of additional wind generation in this area.

[80] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets/victorian-renewable-energy-target-auction-vret2.

5.6 Inertia outlook

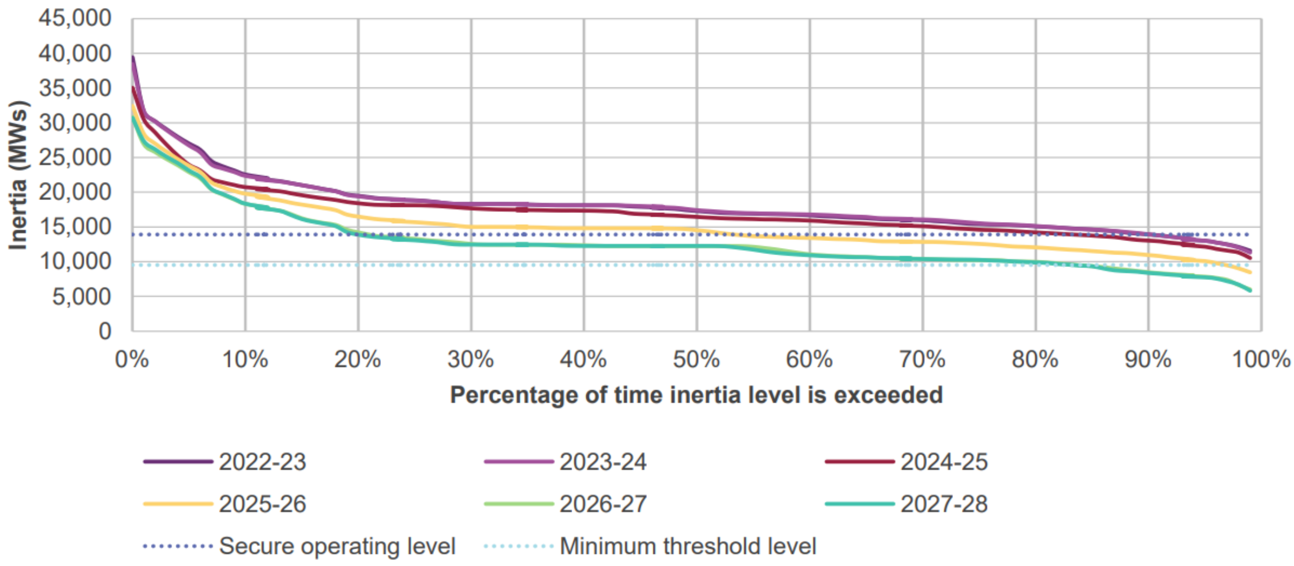
Power systems with high inertia can resist large changes in system frequency arising from contingency events that create an imbalance between supply and demand.

With the increase in CER and non-synchronous renewable generation, and the reduction in the number of coal-fired generating units online, system inertia is likely to decrease, making it more difficult to manage power system frequency events. Under the NER (and in accordance with the published Inertia Requirements Methodology[81]), the satisfactory and secure requirements for synchronous inertia are identified for each NEM region under islanded operating conditions. As the Inertia Service Provider for Victoria, AVP is required to remediate any inertia shortfall identified.

In the 2022 *Inertia Report*[82], AEMO (as national planner):

- Projected that inertia in Victoria will decline below the minimum threshold level of inertia and secure operating level of inertia within the next five years for a completely islanded Victorian region, as indicated in **Figure 25**. AEMO has not declared a gap for Victoria ,as islanding of Victoria alone remains unlikely due to the diversity and number of AC interconnectors that exist between Victoria and adjacent regions.
- Declared an inertia shortfall for the sub-region of Victoria and South Australia, ranging from 2,421 MWs to 2,482 MWs against the secure operating level, from 1 July 2026 onwards as indicated in **Figure 26**.

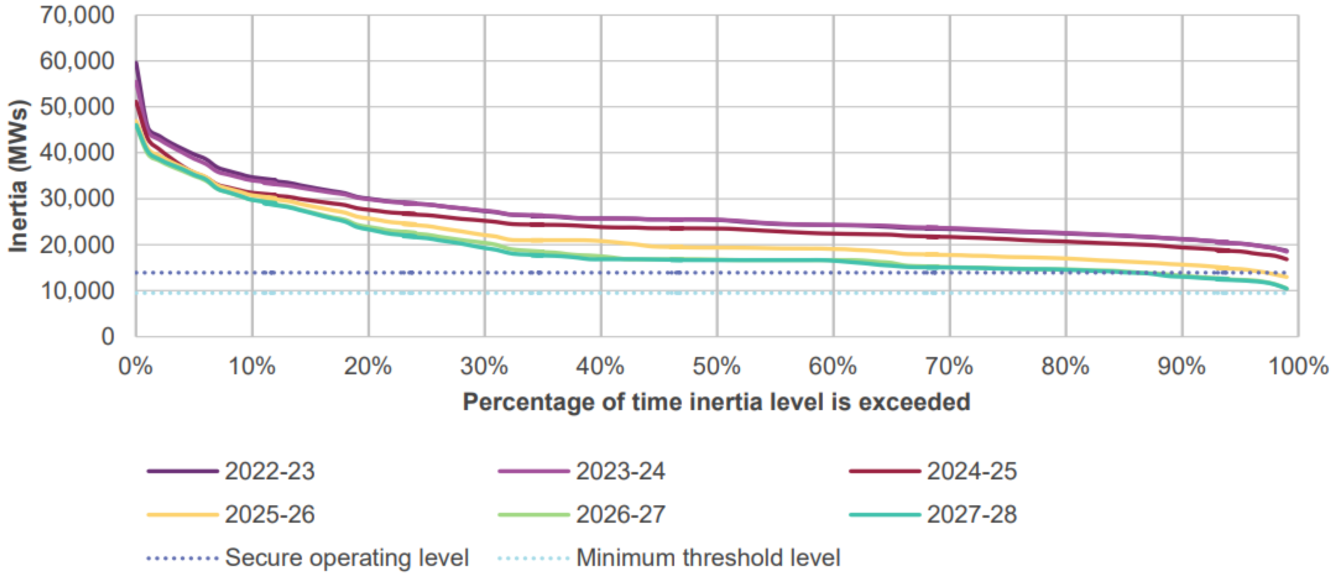
Figure 25 Projected inertia for the five-year outlook, *Step Change* scenario, Victoria (MWs)



81 AEMO, *Inertia Requirements Methodology Inertia Requirements and Shortfalls*, June 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

82 AEMO, *2022 Inertia Report*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-inertia-report.pdf?la=en.

Figure 26 Projected inertia for the five-year outlook, *Step Change* scenario, South Australia and Victoria (MWs)



As historical islanding events have occurred between New South Wales and Victoria[83] (which led to Victoria and South Australia islanding with a small section of New South Wales), AEMO, as national planner, has assessed the inertia levels for the combined islanding of South Australia and Victoria and accounted for these in the inertia requirements for each inertia subnetwork.

The inertia shortfall was declared for Victoria and not South Australia due to the relative availability of forecast inertia in each region to meet its own secure operating level of inertia. It should also be noted that the four synchronous condensers at Buronga and Dinawan built with EnergyConnect may impact the amount of inertia available to Victoria and South Australia in an islanding event but were not part of the projected forecast due to the lack of information at that time on the control schemes being implemented as part of EnergyConnect and final equipment design.

As such, AVP is actively engaging with AEMO (as national planner) to refine the inertia shortfall with the latest network developments, including special control schemes. As noted in Section 5.2.1, AVP is undertaking a RIT-T to procure system strength services for Victoria. AVP will consider system strength services which also provide inertia as a potential class of benefits that may help address any remaining inertia shortfall.

AVP also notes the ongoing AEMC rule change “Improving security frameworks for the energy transition”[84] which may have implications on AVP as the inertia service provider.

[83] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en.

[84] AEMC, Improving security frameworks for the energy transition, at https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

5.7 General Power System Risk Review (GPSRR)

AEMO published its 2023 General Power System Risk Review (GPSRR) report in July 2023, undertaken under rule 5.20A of the National Electricity Rules (NER). This is AEMO's first GPSRR report, replacing the former biennial Power System Frequency Risk Review (PSFRR) report.

The GPSRR is an integrated, annual review of major power system risks in the National Electricity Market (NEM). AEMO, in its role as NEM Operator, undertakes this review in consultation with TNSPs.

The 2023 GPSRR is available on the AEMO website[85].

Relevant 2023 GPSRR risks and recommendations:

2023 GPSRR Risk 4: A selection of non-credible events, some of which are in South West Victoria, could lead to QNI instability, considering the increase in QNI power transfer limit planned as part of the QNI Minor upgrade. This risk was identified in studies against future operating conditions for financial year 2027-28. Consistent with the 2022 PSFRR, the 2023 GPSRR highlighted that under certain scenarios, loss of 500kV lines at Moorabool Terminal Station (MLTS)[86] could result in a large power swing on Energy Connect even with operation of the South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS). This power swing could lead to the tripping of EnergyConnect and the synchronous separation of South Australia, as well as the tripping of QNI and the synchronous separation of Queensland.

2023 GPSRR Recommendation 3 to address Risk 4

Given the potential for Moorabool contingency events to result in separation of the mainland NEM into four islanded areas – Queensland, South Australia (separated at Heywood following Emergency Alcoa Potline Tripping – EAPT operation), the network between Heywood and Moorabool (not a viable island) and the rest of New South Wales and Victoria – AEMO recommends that AEMO, AVP, ElectraNet and Transgrid continue collaborating as part of the Project EnergyConnect System Integration Steering Committee (SISC) to ensure that the SAIT RAS operates effectively in conjunction with existing NEM system protection and generation tripping schemes, as well as any future QNI SPS and other protection schemes.

In response to the above GPSRR recommendation, AVP is actively collaborating with ElectraNet to identify a range of solutions to address 2023 GPSRR Risk 4. Refer Section 5.8 for more details.

5.8 Victorian control schemes

As outlined in the 2022 VAPR, AVP has assessed the impacts of committed network projects and generation connection projects on existing control schemes and identified the needs for new control schemes. Currently AVP is progressing the review of a set of existing control schemes which could be impacted by these network changes, as well as the development of new control schemes to address the recommendations from 2022 PSFRR[87] and 2023 GPSRR as described below:

[85] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review.

[86] Specifically combined loss of MLTS-(MOPS and MLTS-Haunted Gully Terminal Station (HGTS) 500 kV lines.

[87] Refer to recommendations 2 and 10, AEMO *2022 Power System Frequency Risk Review*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.

- The review of existing control schemes to accommodate EnergyConnect Stage 1 has been completed and modification of relevant control schemes is underway. In addition, AVP has jointly worked with Transgrid to confirm the instability risk identified in the 2022 PSFRR for loss of both Dederang – South Morang 330 kV lines during Victoria export to New South Wales, and to assess the need for a new control scheme to address the instability issue as recommended by the 2022 PSFRR. The assessment indicated that a control scheme involving generation tripping and load shedding could address the instability issue and AVP is conducting power system studies to determine functional requirements for the new control scheme.
- AVP and ElectraNet are initiating a joint planning project to determine the functional requirements for a new control scheme, and modifications to existing control schemes if necessary, to manage the GPSRR Risk 4 as recommended in the 2023 GPSRR (refer to Section 5.7).
- AVP is currently designing an additional scheme for post completion of WRL project to mitigate the impact of double circuit 500 kV outage of the lines between Bulgana and Sydenham. A similar scheme will be designed for VNI West scheme to minimise the impact of double circuit 500 kV outage of the lines between Bulgana, Kerang and Dinawan. These schemes will likely include tripping of generators and loads where necessary to prevent system instability and potential overloading of the remaining transmission network. The designs will consider a range of operating conditions and the probability of those conditions in line with the Victorian planning approach.

AVP will continue to monitor changes in network configuration and operating conditions, including connection point demand, new generation connection and retirements of existing generation, and upgrade the Victorian control schemes whenever necessary to ensure their effectiveness and appropriateness.

5.9 Updating the Transmission Development Plan

The majority of the Victorian transmission network was designed and built based on the main source of supply being the coal-fired generators in the Latrobe Valley. From the Latrobe Valley, the transmission network takes energy predominantly in a westward direction towards the eastern side of Melbourne and then continues to branch out further in northerly and westerly directions to supply loads and form interconnectors with New South Wales and South Australia.

In general terms, the capacity of the existing network continues to diminish the further west and north it extends from the Latrobe Valley, except for the lines specifically connecting New South Wales and South Australia and operating as higher capacity (and higher voltage) interconnectors. This was correctly seen as the least-cost technically acceptable initial power system design for supplying Victorian customers and the interconnectors, based on the majority of the supply coming from the Latrobe Valley.

After Victoria's brown coal generators retire, there are expected to be times supply will come from many different areas of Victoria and will be imported via interconnectors, and the historic network will no longer be adequate to get electricity to consumers.

While works are already underway in some areas where good renewable resources are available, to increase the capacity of the network to allow the connection of more generators, as outlined in Section 4, this will not address the issues forecast to occur closer to load centres by virtue of the change in location of major electricity supplies.

For example, the lines on the eastern side of Melbourne have capacity to carry energy to the western side of Melbourne with supply from the Latrobe Valley. In the future, however, at times when majority of the supply comes from renewables in Western Victoria due to intermittency of the resources supplying the generation, some of the lines on Melbourne's western fringes will not have the capacity to supply loads in eastern Melbourne without augmentation. While the installation of offshore wind generators in Gippsland will support utilisation of the existing network capacity, this supply would be intermittent, and there will be times when energy will be provided from other locations.

AVP has therefore identified the need to update its Transmission Development Plan for Victoria to include projects to reinforce both eastern and western metro area to supply the growing Melbourne load from geographically and temporally diverse generation sources.

5.9.1 Western Metro area reinforcement

AVP has identified a need to reassess the current configuration of the Western Metro network to holistically address a number of inter-related limitations and challenges which are anticipated to arise as both demand and supply in the state's west continue to grow. Significant changes to supply, demand, and the network have already occurred in the Western metro and regional areas over the last decade which have impacted how assets are utilised in the network, including:

- Retirement of Port Henry Smelter at Geelong.
- Establishment of Deer Park load terminal station.
- Construction of a third 220 kV line between Ballarat and Moorabool.
- Significant increase in 500 kV and 220 kV-connected wind and BESS capacity.

Additional significant changes in the Western metro, regional and rural Victorian areas are anticipated over the next decade, including WRL, VNI West, RDP Stage 1 projects, Keilor transformer end of life refurbishment, significant additional BESS capacity, retirement of metro capacitor banks and more (see sections 4.1, 5.2 and 7.1). AVP intends to commence a holistic assessment of the Western Metro network configuration to ensure that the network is utilised efficiently under future system conditions. This will include:

- Identifying options that address the developing and priority limitations on the Moorabool – Geelong – Keilor corridor (limitations 4 and 10) by balancing the sharing of power between 220 kV and 500 kV entry points into the Western Metro area to maximise their utilisation.
- Managing maximum fault levels at terminal stations under future conditions.
- Assessing options for replacement of assets reaching end of life in the coming decade, including the Keilor A4 transformer (see Section 7.1).
- Joint planning with NSPs to accommodate future terminal stations and address developing thermal and voltage stability limitations arising due to future load growth at Deer Park (limitations #8 and #9).

5.9.2 Eastern Metro area reinforcement

AVP has identified a need to reassess the current configuration of the Eastern Metro network to holistically address a number of inter-related limitations and challenges which are anticipated to arise as both demand and supply in the state's west continue to grow and change. Changes in the Eastern Metro network over the last decade have been modest compared to some other areas of the state and the existing arrangements have therefore been adequate to meet the needs of Victorian consumers so far. However, significant changes in the Eastern metro network are starting to occur and are anticipated to continue over the next decade, including:

- Retirement of Yallourn Power station in 2028, and Loy Yang A by 2035.
- Connection of the first Marinus Link cable in 2029-30.
- Connection of 2 GW of offshore wind by 2032 to meet the Victorian Government's Offshore wind target[88].
- Load growth projected to exceed the capacity of the Eastern Metro network in its current configuration.
- Hazelwood and South Morang transformer end of life refurbishments (see Section 7.1), and more.

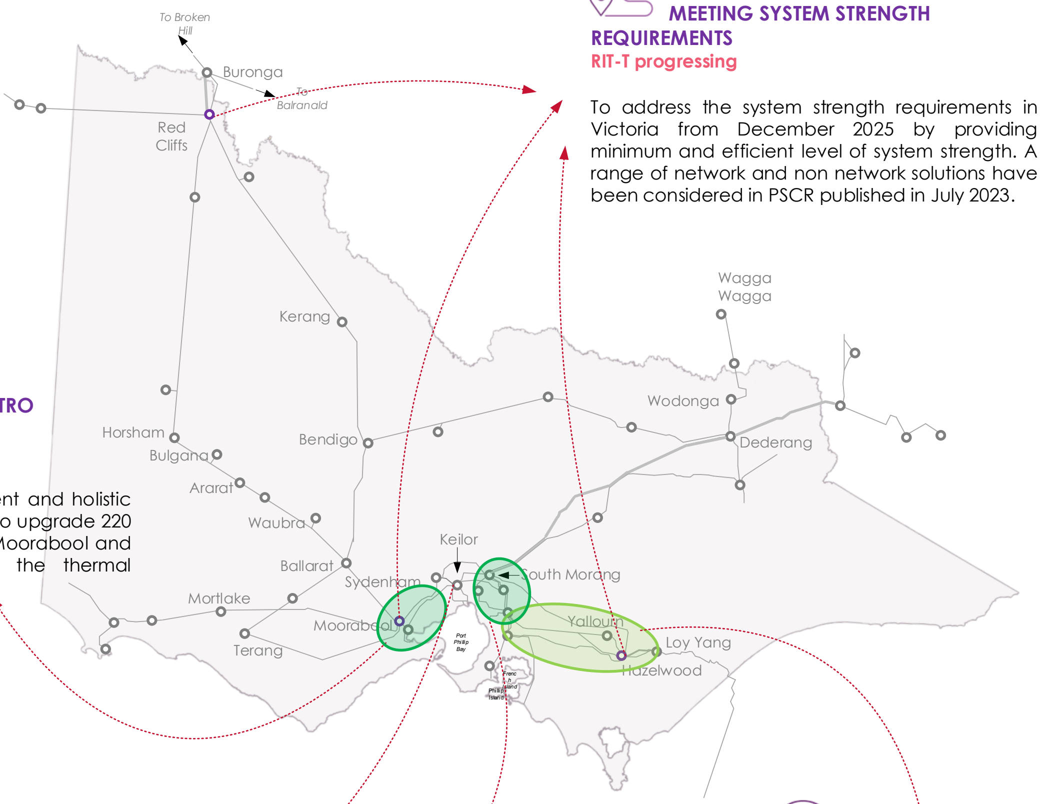
Based on current 2023 IASR demand forecasts, the preferred switching arrangement at Hazelwood outlined in Section 5.3.1 should maintain loading on network elements in the Eastern Metro network below their thermal ratings until 2030-31. Beyond 2030-31, further network and/or non-network options to increase the DSN capacity of the wider Eastern Metro network are likely to be needed.

AVP intends to commence a holistic power system and economic assessment of the Eastern Metro network configuration to ensure that the network is utilised efficiently under future system conditions, and determine whether additional investment is needed to support forecast load growth. This will include:

- Addressing emerging limitations (limitations #5 and #6) by balancing the sharing of load across Eastern Metro bus groups.
- Managing maximum fault levels at Metropolitan and Latrobe Valley terminal stations under future arrangements.
- Assessing options for renewal of assets reaching end of life in the coming decade including replacement of the South Morang H1 transformer and KTS A transformers as well as refurbishment of the Hazelwood A2, A3, and A4 transformers (see Section 7.1).
- Advertisement of NMAS opportunities for load and generation developments in the Eastern Metro network.

[88] Note that for the purpose of this Annual Planning Review, this first 2 GW is assumed to be in Gippsland due to the development and licensing process being more advanced in this area than in Portland.

Figure 27 Updates to the Development Plan from 2023 VAPR



MEETING SYSTEM STRENGTH REQUIREMENTS
RIT-T progressing

To address the system strength requirements in Victoria from December 2025 by providing minimum and efficient level of system strength. A range of network and non network solutions have been considered in PSCR published in July 2023.

WESTERN-METRO REINFORCEMENT
Future RIT-T

Pre-feasibility assessment and holistic studies to initiate RIT-T to upgrade 220 kV corridor between Moorabool and Geelong to remove the thermal limitation.

METROPOLITAN MELBOURNE VOLTAGE MANAGEMENT
RIT-T progressing

To provide reactive support to maintain the voltages in metropolitan area within the limits during minimum and maximum demand times. PSCR published in October 2023.

EASTERN-METRO REINFORCEMENT
Future RIT-T

Pre-feasibility assessment and holistic studies to initiate RIT-T to relieve the thermal limitations in eastern metro area.

MINOR AUGMENTATION TO SUPPORT LATROBE VALLEY RE-CONFIGURATION
Minor augmentation

Initiate a project to assess the required minor augmentation works to re-configure the 220 kV network in Latrobe Valley to operate after Yallourn retirement.

6 System strength and available fault level forecasts

This section provides a high level explanation of system strength, the new rule change that came into effect December 2022, and AVP's available fault level forecasts that are now an annual requirement to be published with the VAPR.

What is system strength?

System strength is the ability of the power system to maintain a stable voltage waveform at any given location in the power system, both during steady state operation and following a disturbance. AVP has an important role in ensuring sufficient system strength as the System Strength Service Provider for Victoria.

Until 1 December 2025, AVP is responsible for making system strength services available to meet any fault level shortfall related to decreasing supply of system strength as declared by AEMO as the National Planner through the annual System Strength Reports[89].

From 2 December 2025 onwards, under a new system strength framework introduced by the AEMC's rule change on Efficient Management of System Strength on the Power System[90], AVP will be required to use reasonable endeavours to plan for system strength services to meet the three-phase fault level requirement and stable voltage waveform criteria for a secure system under forecast future IBR connections for each system strength node as part of a system strength standard; that is, AVP must plan to meet the current and future system strength need for Victoria.

The minimum three-phase fault level and efficient IBR forecast applicable three years ahead of time is published by AEMO as National Planner through the annual System Strength Reports. AEMO (in its role as the national transmission planner) published the first System Strength Report in December 2022 under the evolved framework that defines the system strength requirements for Victoria over a 10-year outlook period.

The stable voltage waveform criteria is published by AEMO as National Planner in the System Strength Requirements Methodology. These reports are published on AEMO's System Security Planning webpage[91].

Declared and near-term shortfalls

There are no previously declared shortfalls left unaddressed on the DSN prior to December 2025.

Looking forward, AEMO's 2022 *System Strength Report*[92] identified potential lack of system strength shortfalls at Hazelwood, Thomastown and Moorabool from 2026-27 onwards, however it is expected the new system strength standard will be met after December 2025, so a formal shortfall was not declared.

[89] AEMO, System Security Planning page, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[90] See https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[91] AEMO, System Security Planning page, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[92] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-system-strength-report.pdf?la=en.

Available fault level forecasts

The available fault level (AFL) is a proxy used to quantify the indicative impact of IBR on the power system. AFL is intended to provide locational signals for IBR connections on connection points that may be more susceptible to issues as more IBR connects.

Under NER 5.20C.3 (f) (3), AVP as SSSP for Victoria must publish forecast of the AFL at each system strength node over the period for which AEMO has determined system strength requirements, in a manner consistent with the methodology in the system strength impact assessment guidelines (SSIAG) [93]. AEMO as National Planner published a methodology for forecasting AFL at system strength nodes in section 3.4.3 of the 2023 update to the SSIAG. AVP has prepared its first AFL forecast in line with this methodology for the 2023 VAPR, using the following inputs and assumptions. These are consistent with the inputs and assumptions used in the Victorian System Strength Requirements PSCR except where otherwise stated.

The inputs into the AFL forecast includes:

- Equivalent network solution to meet the network solution to meet the system strength standard shown in **Table 16**.
- RDP Stage 1 projects (Ararat Synchronous Condenser and Koorangie BESS).
- EnergyConnect synchronous condensers at Buronga and Dinawan.
- All existing and committed IBR generators and storage as per the July 2023 update to AEMO's generation information page[94], which includes IBR generators which have reached commitment status since publication of the Victorian System Strength Requirements PSCR.
- Existing DC interconnectors Murraylink and Basslink.

Table 16 Forecast of available fault Levels (pre-contingent) for Victoria under an equivalent network solution to meet the system strength standard (MVA)

	2025	2026	2027	2028	2029	2030	2031	2032	2033
Dederang 220kV	891	1,185	1,448	1,480	1,480	1,937	1,937	2,205	2,205
Hazelwood 500kV	516	1,353	1,695	1,485	1,485	3,445	3,445	4,018	4,018
Moorabool 220kV	0	1,052	1,073	1,117	1,117	2,562	2,562	3,053	3,053
Red Cliffs 220kV	0	0	546	552	552	687	687	1,029	1,029
Thomastown 220kV	960	1,486	1,734	1,818	1,818	2,986	2,986	3,340	3,340

As system strength services for efficient level of future IBR may be more effectively located closer to forecast IBR generation, the resulting increase in AFL at the system strength node could be reduced. This however does not impact the capability of the equivalent network solution to ensure stable voltage waveform for the forecast IBR generation.

[93] AEMO, *System Strength Impact Assessment Guidelines v2.1,* June 2023, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/ssrmiag/amendment/system-strength-impact-assessment-guidelines-v21.pdf?la=en.

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

7 Joint planning to maintain the network

This section:

- Addresses NER requirements on AVP as the Jurisdictional Planning Body related to joint planning with Declared Transmission System Operators (DSTOs) for DSN asset retirement, deratings, and replacement as per NER 5.12.2.c.(1A).
- Provides details on joint planning activities with other TNSPs per NER 5.12.2.c.12 and Victorian DNSPs under the requirements of NER 5.14.1.

More details are provided in AusNet Services' asset renewal plan, which is available with the VAPR on AEMO's website. Details of current RIT-Ts are also available at AusNet Services' website[95].

Joint planning in relation to retirement or de-ratings of DSN assets

While previous sections have focused on the need for network augmentation, appropriate maintenance of Victoria's existing network asset base remains critical. In 2023, AEMO has again worked closely with AusNet Services to assess the need for the replacement, refurbishment, derating, or retirement of existing DSN assets that are approaching end-of-life.

In the 2023 VAPR:

- AusNet Services' 2023 asset replacement and refurbishment plans are largely consistent with those presented in the 2022 VAPR.
- Six new asset replacement projects have been identified, or have now moved within the assessment horizon:
  - 220 kV circuit breaker replacement at Rowville Terminal Station (ROTS).
  - Tower replacement works (Stage 1 and Stage 2) in Heywood to Alcoa Portland 500 kV line (HYTS-APD).
  - H3 330/220 kV transformer and 330 kV circuit breaker replacement at Dederang Terminal Station (DDTS).
  - 220 kV and 66 kV circuit breaker replacement at Geelong Terminal Station (GTS).
  - 220/66 kV transformer and 22 kV circuit breaker replacement at Kerang Terminal Station (KGTS).
  - B3 transformer replacement at Ringwood Terminal Station (RWTS).
- One asset renewal project has moved beyond AusNet Services' 10 year renewal plan following an updated asset condition assessment:
  - Wodonga Terminal Station (WOTS) 330 kV and 66 kV circuit breaker replacement.

95 https://www.ausnetservices.com.au/projects-and-innovation/regulatory-investment-test

7.1 Asset retirement and de-ratings in the DSN

7.1.1 Rule requirements for DSN asset retirements/de-ratings

Due to ageing transmission assets, changes in technology, and slowing demand growth, there is an increasing need to coordinate DSN asset renewal and augmentation activities in Victoria, and to assess both the system need and economic justification for the replacement of existing assets.

In Victoria, AusNet Services is responsible for assessing the condition of its Victorian DSN assets, and for making replacement, retirement, or derating decisions for those assets.

As the Jurisdictional Planning Body (JPB) for Victoria, AVP's primary involvement is in providing planning advice to AusNet Services (particularly on the continued system need for individual DSN assets).

Under NER 5.12.2, regional Transmission Annual Planning Reports (TAPRs) must include detailed information relating to all network asset retirements and deratings that would result in a network constraint over the planning period. AusNet Services' current asset renewal plan is available alongside the VAPR on the AVP website[96]. Details of current replacement RIT-Ts are also available at AusNet Services' website[97].

Under NER 5.14.1, where there is an identified need to retain an asset, AVP and AusNet Services conduct joint planning to identify the most efficient and economic option to address the identified need. The following sections provide more information about the joint planning process for asset retirement, replacement, refurbishment, and deratings.

7.1.2 Methodology

AVP and AusNet Services agreed on an approach for joint planning which was adopted in this VAPR:

- AVP and AusNet Services jointly selected a set of assets which are included in AusNet Services' Asset Renewal Plan and are likely to create a DSN constraint which potentially justify RIT-Ts for replacement.
  - The selected assets were grouped with their associated network components whenever possible, and a need assessment was conducted by assessing the overall network impacts of retiring the asset.
  - Circuit breakers, other switchgear, and secondary systems were grouped with their respective associated network components, such as transmission circuits, transformers, generators, or reactive plants whenever possible.
- Committed (asset replacement) projects, projects for which RIT-Ts have been completed for asset replacement, and projects associated with transmission assets that do not form part of the DSN were excluded from the network need assessment, although noting that any subsequent economic justification for replacement would need to take other planned developments on the DSN into account.
- Most of the secondary equipment (such as communication systems and control batteries), structural assets (for example towers), and ground wires in the Asset Renewal Plan were excluded from the network need assessment for individual projects. These assets are considered essential to the associated DSN primary network components, and therefore they will be needed while the associated primary network components are

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

[97] See https://www.ausnetservices.com.au/projects-and-innovation/regulatory-investment-test.

still in service. As there is no committed retirement of Victorian transmission lines or Victorian interconnectors at present, AVP and AusNet Services agreed that all the secondary and structural assets which are associated with the Victorian transmission lines and interconnectors are still required, without carrying out need assessment on individual projects.

- AVP undertook a desktop analysis to assess whether the retirement of the selected asset would result in a network impact (that is, a network need for its replacement). In the case of an asset retirement that causes the disconnection of a generator, the resulting reduction in supply availability was also considered.
- If the proposed retirements would cause line, transformer, or static var compensator (SVC) outages, the impact of a credible contingency under worst-case operational conditions (normally either maximum or minimum demand conditions) was examined with a prior outage of the respective network element.

7.1.3 Needs assessment results

Table 17 presents the summarised findings from the assets needs assessment.

Table 17 Network needs assessment results

Project name	Location	Total cost (real $M)	Target completion (December)	Major DSN assets component(s)	Retirement outcome
Hazelwood Terminal Station A2, A3 and A4 Transformer Refurbishment	Hazelwood Terminal Station	10	2025	HWTS A2, A3 and A4 500/220 kV transformers	Reduced capability of the 500kV transformation at Hazelwood in the short term.[98] Reduced reliability and capability to supply Melbourne eastern metro load in the long term.
HYTS-APD tower replacement – Stage 1	HYTS-APD line	31	2026	Selected towers, conductor and ground wire	Loss of connection to Alcoa Portland and embedded wind farms.
Keilor Terminal Station A4 500/220kV Transformer Replacement	Keilor Terminal Station	71	2028	Keilor A4 750 MVA 500/220 kV transformer	Reduced reliability and capability to meet peak demand under certain operating conditions. [99]
				Keilor 220 kV capacitor bank No. 1 and Keilor 66 kV capacitor bank 1B	May reduce maximum supportable demand caused by reduced reactive power margin. [100]
South Morang Terminal Station 330/220kV Transformer Replacement - Stage 2	South Morang Terminal Station	44	2029	South Morang 330/220 kV H1 transformer	Reduced reliability and capability to meet peak demand.
South Morang Terminal Station 500kV GIS Replacement - Stage 1	South Morang Terminal Station	18	2028	South Morang – Hazelwood 500 kV No. 1 Line breaker-and-half switch bay South Morang – Sydenham 500 kV No. 1 Line breaker-and-half switch bay	Reduced reliability and interconnector capabilities.

[98] The proposed life extension refurbishment is expected to be the least cost means of providing this transformation capability when needed to retain Latrobe Valley to Melbourne 220kV transfer capability after Yallourn Power Station generation retires. AVP has identified a need to reassess the configuration of the Latrobe Valley and wider Eastern Metro network (see section 4.4.2).

[99] AusNet Services' RIT-T will consider replacing one, two or all three Keilor transformer banks, with A4 transformer expected to occur first. AusNet Services and AEMO will continuously work together to determine the preferred option in replacing the existing Keilor transformers. This is intended to occur as part of a holistic assessment of the Western Metro network configuration (see section 4.4.1).

[100] In addition to maximum supportable demand, AEMO also assessed the impact of in-service 220 kV or 66 kV cap banks on Victorian import voltage stability limits and voltage control. Study results indicated that retiring any existing capacitor bank could reduce the Victorian import voltage stability limit from New South Wales, however not all capacitor banks are required to be in-service at the same time for voltage control. Further studies using a voltage stability assessment tool (VSAT) have also confirmed the impact of these capacitor banks on Victorian import voltage stability limit. The retirement impacts of capacitor bank circuit breakers and their associated capacitor banks are inter-dependent. See https://aemo.com.au/initiatives/major-programs/metropolitan-melbourne-voltage-management-regulatory-investment-test-for-transmission.

Project name	Location	Total cost (real $M)	Target completion (December)	Major DSN assets component(s)	Retirement outcome
Thomastown Terminal Station Circuit Breaker Replacement	Thomastown Terminal Station	19	2029	Thomastown 220 kV No.1 and 66 kV 4B capacitor bank circuit breakers	May reduce maximum supportable demand caused by reduced reactive power margin.[101]
Loy Yang Power Station and Hazelwood Terminal Station 500kV Circuit Breaker Replacement - Stage 2	Loy Yang Power Station and Hazelwood	60	2030	Loy Yang – Hazelwood 500 kV No. 1 line double breaker switch bay Loy Yang – Hazelwood 500 kV No. 2 line Loy Yang – Hazelwood 500 kV No. 3 line Hazelwood – Loy Yang 500 kV No. 2 line and Hazelwood – Loy Yang 500 kV No. 3 line and Hazelwood – Rowville 500 kV No. 3 line breaker-and-half switch bay (Hazelwood end) Hazelwood – Cranbourne 500 kV No. 4 line breaker-and-half switch bay (Hazelwood end)	Generation constraints and reduced reliability.
Newport Power Station 220 kV GIS	Newport Power Station Switchyard	55	2030	Newport – Brooklyn 220 kV line Newport – Fishermans Bend- 220 kV line	Loss of connection to Newport generation (noting Newport expected closure year is 2039).
Loy Yang 66 kV Circuit Breaker Replacement	Loy Yang 66kV Switch Yard	14	2030	Loy Yang – Morwell 66 kV line No. 1,2,3 and 4 Loy Yang 66 kV capacitor banks No.1 and No.2	Loss of supply for emergency fire services (noting expected closure of Loy Yang coal-fired generators commencing 2035).
Morwell Terminal Station 66kV Circuit Breaker Replacement	Morwell Terminal Station	6	2030	Morwell to Loy Yang 66 kV line No. 3 and No.4	Loss of supply for Loy Yang raw coal bunker emergency fire services, potentially resulting in no Loy Yang generation (A or B) for up to 6 months.
Rowville 220kV Circuit Breaker Replacement	Rowville Terminal Station	10	2030	Rowville No.1 and No.2 Static Var Compensation	Reduced maximum supportable demand.

[101] In addition to maximum supportable demand, AVP also assessed the impact of in-service 220 kV or 66 kV capacitor banks on Victorian import voltage stability limits and voltage control. Studies results indicated that retiring any existing capacitor bank could reduce the Victorian import voltage stability limit from New South Wales, however not all capacitor banks are required to be in-service at the same time for voltage control. Further studies using a voltage stability assessment tool (VSAT) have also confirmed the impact of these capacitor banks on Victorian import voltage stability limit. The retirement impacts of capacitor bank circuit breakers and their associated capacitor banks are inter-dependent. See https://aemo.com.au/initiatives/major-programs/metropolitan-melbourne-voltage-management-regulatory-investment-test-for-transmission.

Project name	Location	Total cost (real $M)	Target completion (December)	Major DSN assets component(s)	Retirement outcome
				Rowville 220kV capacitor bank circuit breakers	May reduce maximum supportable demand caused by reduced reactive power margin.
HYTS-APD tower replacement – Stage 2	Various	72	2031	Selected ground wire & conductor sections	Loss of connection to Alcoa Portland and embedded wind farms.
Yallourn Power Station 220kV Circuit Breaker Replacement - Stage 2	Yallourn Power Station	10	2032	Yallourn – Rowville 220 kV lines No. 5 and No.6 Yallourn – Hazelwood 220 kV lines No. 1 and No. 2	Reduced reliability and capability to supply Melbourne eastern metro load.[102] Following retirement of Yallourn Power Station, these assets are still required to transfer power from the Latrobe Valley to Metropolitan Melbourne.
Dederang H3 330/220kV Transformer and 330kV Circuit Breaker Replacement	Dederang Terminal Station	28	2032	One 340MVA 330/220kV transformer and two 330kV circuit breakers	Reduced reliability and capability to supply Mt Beauty and Glenrowan (220kV) and reduced VIC to NSW export capability.
Geelong 220kV & 66kV Circuit Breaker Replacement	Geelong Terminal Station	18	2032	GTS-MLTS No.2 220kV circuit breaker GTS No.1 BUS -KTS No.3 220kV circuit breaker	Reduced reliability to supply Geelong and Deer Park area load. Replacement of these assets may be incorporated into augmentation options for upgrading GTS-MLTS and the Western Metro network.

[102] Hazelwood transformation allows continued utilisation of Latrobe Valley to Melbourne 220 kV lines to supply Melbourne eastern metro load.

7.1.4 Asset renewal regulatory investment test projects

AusNet Services completed RIT-Ts for the following asset renewal projects since publication of the 2022 VAPR:

- South West Network Communications replacement
- Maintain reliable transmission network services from Red Cliffs Terminal Station (RCTS) with an asset replacement project that includes transformer replacements at RCTS.
- Conductor and ground wire replacement – Phase 1.

AusNet Services is progressing several DSN asset renewal project RIT-Ts on primary and secondary assets as detailed below.

Tower strengthening between Murray Switching Station (MSS) and Dederang Terminal Station (DDTS)

The Murray to Dederang transmission lines (MSS-DDTS 1&2) towers were built from 1959 to 1965 to State Electricity Commission of Victoria design codes that applied at that time. The current design standard (AS/NZS 7000-2016) accounts for the risks associated with high intensity wind loading from thunderstorms and downburst winds and the risk of cascade failures (multiple tower collapse during a single event).

AusNet Services commenced a RIT-T to identify the preferred option to strengthen the existing transmission towers associated with the MSS–DDTS lines, to meet the requirements in the current design standard. This RIT-T is needed to maintain the required reliability of transmission network services and ensure that AusNet Services complies with its regulatory obligations, including those in the *Electricity Safety Act 1998*.

AusNet Services published the PSCR in April 2022[103] and expects to publish the PACR by end of 2023.

Transmission Line Insulator Replacement Program

AusNet Services commenced a RIT-T to identify the preferred option to replace aging transmission line insulators. This RIT is needed to:

- Maintain the required reliability of transmission network services across its transmission network, through actively managing the risks and consequences of transmission line insulator failures.
- Ensure that AusNet Services complies with its regulatory obligations, including those in the *Electricity Safety Act 1998.*

AusNet Services published the PSCR in June 2022[104] and expects to publish the PACR in November 2023.

7.2 Joint planning with other TNSPs

Under the requirements of NER 5.14. 3, TNSPs must undertake joint planning if:

[103] See *Tower Strengthening: Murray Switching Station to Dederang Terminal Station* PSCR: https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/about/regulatory-investment-test/regulatory-investment-test-for-transmission-pdfs/murray-rit-t_tower-strengthening_pscr.pdf.

[104] See *Transmission Line Insulator Replacement Program* PSCR https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/about/regulatory-investment-test/rit-t_insulator-replacement-program-pscr.pdf.

- a possible credible option to address a constraint in a transmission network is an augmentation to the transmission network of another TNSP; and
- the constraint is not already being considered under other processes under the Rules.

AVP has undertaken joint planning activities with neighbouring TNSPs for augmentation works involved with upgrades to the existing interconnectors and planned new interconnectors including EnergyConnect, and VNI West. This includes any inter-network testing associated with any project that augments interconnectors. AVP would also undertake joint planning with neighbouring TNSPs in developing control schemes which could affect power system performance in multiple states or respond to recommendations from the GPSRR.

See Section 4.1 for more details about EnergyConnect and VNI West projects, and Section 5.8 for more information about Victorian control schemes.

7.3 Joint planning with distributors

NER 5.14.1 requires that each TNSP must conduct joint planning with each DNSP of the distribution networks to which the TNSP's networks are connected. To meet this requirement, AVP attends regular joint planning meetings with each Victorian DNSP. In particular AVP is working closely with the relevant DNSP to ensure efficient planning outcomes and to identify the most efficient options to address the following issues.

7.3.1 Geelong fault level

NER 9.3A requires that AVP must, when planning the DSN, use its best endeavours to ensure that fault levels at a 66 kV connection point will not, as a result of a short circuit at that connection point, exceed 21.9kA. In its 2022 annual maximum fault level review, AVP identified that under the worst case scenario[105], Geelong 66 kV fault levels could exceed this 21.9 kA limit whenever the GTS 66 kV buses are tied together. Under the current operational arrangement, the GTS 66kV buses would be normally spilt, and would only be tied together automatically following a GTS 220/66 kV transformer contingency by a Normally-Open-Auto-close (NOAC) control scheme.

AVP is working with AusNet Services and Powercor in developing a plan to keep the fault levels at Geelong 66 kV buses within 21.9 kA, considering future connections and network projects. Long-term solutions include installing new series reactors and viable long-term network reconfigurations. Given that it will take time to identify and implement a preferred long term solution, short-term solutions (including interim measures which could be applied in both transmission and distribution networks to reduce fault levels operationally) are also under investigation jointly with Powercor. If a feasible interim measure is identified, this would provide more headroom to allow for any unexpected increase in fault level, for example, due to connections that are either ahead of schedule or emerging.

7.3.2 High voltage control at connection points

Control of high voltage in both transmission and distribution networks has been challenging during low/minimum demand periods, particularly with increased distributed PV generation. AVP has been working closely with DNSPs and AEMO Operations in developing a voltage management strategy and coordinating transmission and distribution measures, including long-term and short-term solutions to any known voltage control problems.

[105] That is, with all fault current sources connected and all network components in service.

AVP is currently conducting a Metropolitan Melbourne Voltage Management RIT-T. One of the identified needs for this RIT-T is to manage high voltages during low demand periods. The options considered in the RIT-T include the installation of additional reactive power support at 66 kV, which could address high voltage control issues at both transmission and distribution level. Refer to Section 5.2.1 for more information about this RIT-T.

AVP is also liaising with AEMO Operations to apply operational solutions to high voltage problems the Victorian DNSPs have been experiencing, including high voltage control problems in the distribution networks supplied from Deer Park and Western Melbourne terminal stations. The 220/66 kV transformers at these terminal stations were forced to stay at the limit of their tap changers on occasions during low demand periods, due to high voltage on both 220 kV and 66 kV sides. As a result, these transformers lost their voltage regulation capability on these occasions, resulting in undesirable high voltage (greater than 1.05 pu) in the distribution network downstream (as already discussed in Section 2).

AVP and AEMO Operations have identified an operational solution to the problems. AEMO Operation has implemented this operational solution by changing some settings of its Var Dispatch Scheduler (VDS) to keep voltage at the 66 kV connection points at Deer Park and Western Melbourne terminal stations within acceptable ranges.

7.3.3 Transmission connection planning

AVP reviews DNSP plans for existing and new connection points and incorporates the impact of any distribution network modifications in its transmission planning work. AVP and DNSPs work together to resolve connection asset limitations, and this cooperation ensures a co-optimised and efficient solution for both the distribution network and the DSN. **Table 18** includes information on constraints and augmentations identified in the 2022 Transmission Connection Planning Report[106], prepared by the Victorian DNSPs that are assumed to be implemented for the purpose of this Annual Planning Review.

Table 18 DNSP preferred connection modifications

Location/terminal station	Preferred connection modification	DSN impacts and considerations
Altona West (No. 3 and 4 buses) 66 kV	Install an additional 150 MVA 220/66 kV transformer and reconfigure 66 kV exits at ATS by 2025.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.
Cranbourne 66 kV	Install a fourth Cranbourne 150 MVA 220/66 kV transformer by summer 2025-26, as determined by RIT-T.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.
Deer Park 66 kV	Procure a dedicated spare 225 MVA 220/66 kV transformer by end of 2025, subject to RIT-T proposed to commence in 2023.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.
Glenrowan 66 kV	Additional embedded generation may justify additional 220/66 kV transformation capacity.	Monitoring embedded generation output levels will continue, as increased embedded generation will be considered in regional Victoria planning.
South Morang 66 kV	Install a third South Morang 225 MVA 220/66 kV transformer by 2028.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.
Wemen 66 kV	Additional embedded generation may justify additional 220/66 kV transformation capacity.	Monitoring embedded generation output levels will continue, as increased embedded generation will be considered in regional Victoria planning.

[106] See https://jemena.com.au/documents/electricity/2022-tcpr.aspx.

8 Adapting to the future network

With the new VRET target of 95% renewable generation by 2035 and expected retirement of coal generation in Victoria, AEMO is planning for a longer-term future with a diverse technology mix of generation that is distributed throughout rural and regional Victoria. This is a significant step change from the historically centralised location of generation in the Latrobe Valley, which was the foundation for the design of Victoria's transmission network.

This change will require the transmission network to adapt to allow for greater connection of generation and power flows that are in different directions to those the current network was designed for. It will also require additional equipment (in some cases new technologies) to be installed throughout the network to ensure the network remains strong and reliable for consumers.

8.1 Introduction

As the system changes, regional planning processes must adapt to keep pace. These adaptations are occurring across a spectrum of challenging issues:

- **Landscape of Victorian network once coal generation is retired** – transmission challenges projected with Hazelwood, Morwell and Anglesea coal power stations already shut down, Yallourn Power Station retiring in 2028 and the expectation that Loy Yang A will retire in the mid-2030s.
- **Higher instantaneous renewables in Victoria** – the challenges associated with high levels of instantaneous renewables in the network, and the preparatory works that may be required in Victoria for the first periods this occurs, looking ahead to a time when all energy requirements for Victoria and the entire NEM will be met by a combination of renewable generators and batteries.
- **Load/demand patterns** – long-term forecasts for Victoria's summer and winter maximum demands and daytime and night-time minimum demands, and how changes in energy usage are driving the forecasts, as Victoria's population continues to increase, electrification of transport continues, and Victoria transitions away from using natural gas.
- **New technology-based solutions** – how a wide range of new and emerging technologies that are predominantly inverter-based, or based off existing technologies used in a different way or with a different fuel, can provide system strength, inertia, and frequency response services, as well as positive disturbance withstand, island operation and system restoration support.

8.2 Higher instantaneous renewables in Victoria

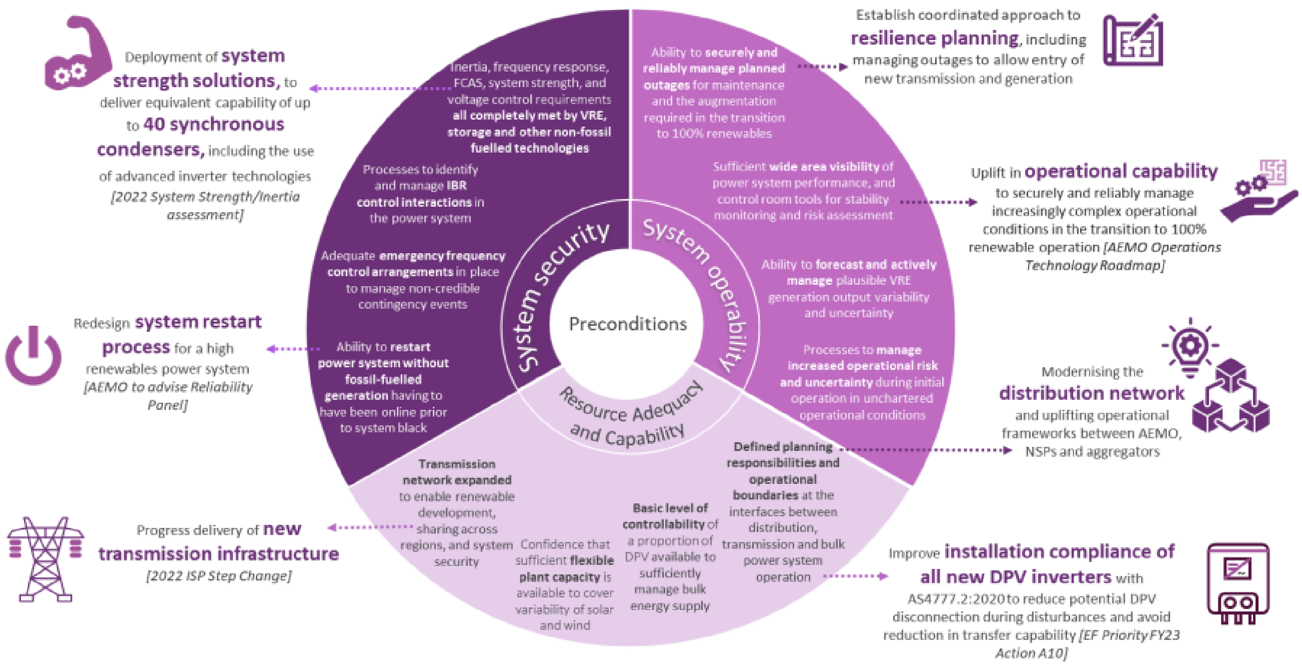
In late September 2023, the NEM hit a record 69.9% for instantaneous renewable penetration over a half-hour period, and AEMO has forecast that there will be enough available capacity for 100% instantaneous penetration NEM-wide as early as 2025. Individual states may have periods of instantaneous 100% renewable energy before the entire NEM does.

AEMO has worked with industry to develop and publish an engineering roadmap to 100% renewables[107], which covers the steps that the NEM, including Victoria, needs to undertake in preparation for the coming system conditions. The key relevant Victoria-specific takeaways are covered in the sections below, with a particular focus on the areas of:

- Power system security.
- System operability.
- Resource adequacy and capability.

Progress adapting in preparation for this future network and areas for future focus for the DSN are also highlighted.

Figure 28 Select actions and technical preconditions required to operate the NEM at up to 100% instantaneous penetration of renewables



Relevant acronyms
DPV: Distributed photovoltaics; **EF:** Engineering Framework; **FCAS:** Frequency control ancillary service; **VRE:** Variable Renewable Energy

From AEMO, Engineering Roadmap to 100% Renewables.

[107] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf?la=en&hash=42E784478D88B1DFAF5D92F7C63D219D.

8.2.1 Power system security

The transition to 100% renewable operation will require the progressive expansion of the technical envelope of the power system to be able to accommodate 100% renewable generation dispatch, with new approaches required to maintain many essential power system requirements that are today provided by fossil fuel generation.

A major technical challenge for maintaining power system security in the renewable transition is the changing stability and dynamics of the power system as it changes from a largely synchronous fossil fuel generation -based power system to one characterised by many (small and large) inverter-based technologies.

The key design choice is compatibility between IBR and the power system:

- How IBR plant should operate in the power system, specified in grid codes and performance requirements, and
- The extent to which the synchronous AC power system itself should evolve to accommodate the IBR, in terms of fundamental control philosophy, system standards and system-level management strategies.

In this context, the roadmap assumes that general principles for maintaining power system security today (as listed in NER 4.2.6) will continue to hold:

- The power system should be operated such that it is and will remain in a secure operating state, to the extent practicable.
- Following a contingency event or a significant change in power system conditions, AEMO should take all reasonable actions to return the power system to a secure operating state within 30 minutes.
- Emergency frequency control schemes are available and in service to restore the power system to a satisfactory operating state following protected events and significantly reduce the risk of cascading outages and major supply disruptions following significant multiple contingency events.
- Sufficient system restart ancillary services (SRAS) are available, in accordance with the system restart standard, to allow the restoration of power system security and any necessary restarting of generating units following a major supply disruption.
- Sufficient inertia should be available in each inertia sub-network to meet the applicable inertia requirements.
- Sufficient three-phase fault level should be maintained at each fault level node to meet the applicable system strength requirements.

To address most of the issues highlighted above it is anticipated that a combination of synchronous condensers (or synchronous generators such as hydroelectric generating turbines operating in a synchronous condenser mode) and advanced inverter technologies such as grid forming would need to be installed. This equipment could become part of the DSN or could be provided by third parties whose system strength services are provided through agreements with AVP.

This equipment would need to be strategically located to give the best outcomes for the Victorian transmission system and may require some network augmentations to be performed. The most likely types of augmentations for this equipment could be:

- The installation of system strength plant in that part of the DSN, which could include synchronous condensers, SVCs and batteries with grid-forming inverters (GFIs).
- Upgrades to station earth grids where local fault levels may rise beyond existing equipment ratings.

- Upgrades to optical ground wire (OPGW) in the transmission network if local fault levels rise beyond existing ratings.
- Changes to protection settings or upgrades related to changes in fault level.
- Upgrades to the transmission network where the increased flow of reactive power pushes equipment beyond existing ratings.

Progress with DSN adaptation

Future system support services are being secured in the DSN, including:

- Agreements with existing synchronous condensers in the North West Victoria/Murray area.
- New Ararat synchronous condenser.
- New Koorangie BESS with GFIs (one of the first GFI BESS in the NEM).

AVP has already commenced works to improve power system security to support the transition to 100% renewable operation, with the two RIT-Ts currently underway (for system strength and reactive support) to ensure required upgrades to the system can be completed by when they are needed (see Section 5.2).

8.2.2 System operability

Managing increasing system complexity in the transition to 100% renewables will require a step change in operational capability. Progressing this uplift while simultaneously operating a real, gigawatt-scale power system is akin to “rebuilding a plane while flying it”.

The renewable transition will involve increasingly complex operational conditions, characterised by:

- Faster, more complex system dynamics with reducing inertia and stability outcomes increasingly determined by fast-acting IBR controls.
- Increasing impact of weather on the supply-demand balance and energy adequacy with increasing volumes of VRE and distributed PV.
- Increasingly decentralised operation through the ongoing uptake of distributed PV and other CER in the distribution network.
- Changing system risk profile and underlying resilience of the system as the system topology and resource mix evolve.

The Operability section of the roadmap identifies the uplift in AEMO and TNSP operational capability required to address this complexity. It covers system resource adequacy and capability, weather monitoring requirements for control room awareness of system state and operational risks; operational processes required to schedule and dispatch the power system and manage the technical envelope; and foundational power system modelling and analysis capability.

Progress with DSN adaptation

Most of the system operability challenges covered in the roadmap do not directly lead to network augmentations being required in the Victorian DSN, because the challenges are mostly around how to operate and manage the network, rather than the capability or capacity of the network.

There are, however, some areas where investment in network equipment may support and improve network operability. These areas include:

- Additional monitoring systems and equipment such as:
  - Weather and wind speed monitoring at more locations.
  - Additional monitoring channels on plant that is currently unmonitored.
  - Higher resolution monitoring equipment where monitoring may already be in place.
- With additional monitoring systems and equipment, the existing systems for transmitting, storing, and processing the data captured by the monitoring equipment may also require upgrades.
- Wind speed and temperature monitoring, and the use of short-term dynamic line ratings have been implemented on most regional 220 kV lines in Victoria, and the approach is used more extensively in Victoria than in other jurisdictions. AVP has already commenced works to install more weather monitoring equipment and capture information, where such monitoring does not currently exist.

8.2.3 Resource adequacy and capability

The first 100% renewable periods will require:

- Sufficient renewable generation online to meet demand at that period.
- Energy adequacy before and after that period so as not to require fossil fuel generation to be online to meet reserve requirements.
- Available dispatchable capacity, to be able to transition in and out of high renewable periods.

The roadmap covers actions necessary to establish the bulk renewable energy, network capability, and resource flexibility necessary to enable this outcome, including:

- Building, connecting, and integrating the renewable energy required to reach 100% renewable resource potential, including utility-scale VRE and CER.
- Planning for structural demand shifts that could materially influence overall capacity and energy requirements, depending on the pace of end use electrification.
- Building and modernising network infrastructure, including transmission network capacity to transfer power from renewable generation centres to load centres, and distribution network capability to accommodate increasing distributed PV and other CER uptake.
- Dispatchable capacity to firm renewable generation variability and uncertainty over different timescales (minutes, hours, and days).

Progress with DSN adaptation

AEMO's ISP, continual improvement in its demand and renewable generation forecasting, and the industry-led connection reform initiative[108] are all playing key roles in ensure there are adequate resources available to meet consumer's evolving expectations.

[108] See https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/connections-reform-initiative.

Resource adequacy and capability is likely to drive the need for expansion and augmentation in the Victorian transmission network, while community and environmental impact will influence the ultimate location and configuration of the network.

The Victorian Government has said that the new VTIF, expected to be legislated next year, has five core elements aimed at ensuring electricity transmission infrastructure in Victoria benefits all Victorians[109]:

- A Victorian transmission planning objective that incorporates environmental objectives and the state's needs in response to the transition to renewable energy.
- A planning process for new major transmission infrastructure and REZs that looks ahead to the next 25 years. As a result of this process, a Victorian Transmission Plan will be published every four years. This Plan will prepare Victoria for a range of possible future scenarios in a way that minimises the risk of both under-investment (not being prepared) and over-investment (building more than is necessary). Importantly, Traditional Owners, local communities, landowners and other regional stakeholders will feed into this planning process early, well before transmission routes are determined.
- A new approach to specifying and procuring projects to meet Victoria's transmission needs, ensuring timely delivery and value for money.
- New arrangements (access scheme) to encourage more renewable energy developers into Victorian REZs by making it easier for new projects to connect to the grid, and providing greater certainty that renewable electricity generated can get to homes and businesses where it is used.
- Place-based approaches to engagement and benefits for impacted Traditional Owners, local communities and landowners. The focus is on collaborative, long-term approaches to build thriving communities delivered in a defined geographic location.

Enabling the connection of additional generators and having sufficient capacity available to meet maximum demand will require network investment, to:

- Extend the transmission network into locations where renewable resources are plentiful but transmission network does not already exist – examples include, VNI West, and the work VicGrid is doing considering options to build out to coastal areas for the connection of offshore wind.
- Bolster the existing network to accommodate the changing of flow paths during times of high demand (the Eastern Metro and Western Metro Reinforcement assessments discussed in Section 5). The existing transmission network is designed for the majority of flow to come from large generators in the Latrobe Valley, but if a large amount of supply comes from Western Victoria instead, the lines around the load centres may not be sufficient.
- Provide additional connection points for the connection of more supply resources, including large-scale batteries. The existing terminal stations in Victoria only have a limited amount of land area in which the equipment to facilitate more connections can be installed, so new sites will be required to facilitate more connections.

[109] See https://www.energy.vic.gov.au/renewable-energy/transmission-and-grid-upgrades.

8.3 New technology-based solutions

A wide range of new and emerging technologies may become part of the network of the future, in varying scale and application. The new technologies are predominantly inverter-based or based off existing technologies used in a different way or with a different fuel. This section discusses:

- Inverter-based technologies including grid forming.
- Hydrogen.
- Storage and batteries.

8.3.1 Inverter-based renewables including grid forming

As more inverter-based generation sources are installed on the network, power electronic inverters will play a larger role in the operation of the power system.

Currently, most inverter-based connections are considered grid-following; this means they require the grid voltage and frequency as a reference point to stay in synchronism with the grid. An important pre-requisite is a stable voltage waveform that the grid-following inverter can track, which means grid-following inverters are less able to operate in parts of the network exhibiting extremely low system strength and where synchronous sources are electrically distant.

Grid-forming inverters is a general term for devices that can use an internal voltage and frequency reference. These devices are less dependent on (or independent of) grid references and have the potential to operate in weaker parts of the network. Grid-forming inverters can strengthen local voltage waveforms and help support nearby grid-following inverters.

However, grid-forming inverters also require extra layers of control systems to maintain synchronism, and to date they have mostly been deployed in smaller, islanded power system applications. In a larger system, multiple grid-forming devices that each follow their own reference point may lead to an uncoordinated or distorted voltage waveform. To resolve this, coordination across the system needs to be considered during planning to avoid system incidents.

AEMO's *Application of Advanced Grid-scale Inverters in the NEM* white paper identified four potential applications for advanced grid-scale inverters, outlined below in order of increasing capability and expected system need and technology maturity over time:

- **Connecting IBR in weak grid areas** – capability to maintain stable operation in weak grid areas to meet IBR performance obligations, and potentially provide system strength to support the connection of other nearby IBR plant. This application provides localised capability to stabilise nearby IBR generation, but does not necessarily support the broader power system.
- **Supporting system security** – capabilities to maintain system security that are predominantly provided by synchronous generators, such as inertia and system strength, to support the broader power system as it transitions to operating with fewer synchronous generators online. Examples of this application include the Victorian Big Battery and the future Koorangie BESS.
- **Island operation** – capabilities to maintain stability and supply balancing at a high enough level to support areas of the grid that become separated from the main synchronous system when operating under high penetrations of IBR.

- **System restart** – capability to energise the local network during the challenging conditions of a black system, or to assist with the restoration process.

Table 19 Summary comparison of inverter and synchronous technologies

Service/Capability	Grid-following inverter system	Grid-forming inverter system	Synchronous machines
Can contribute to system strength		✓·	✓✓ A
Can have positive disturbance withstand (active power oscillation damping)		✓·	✓·
Can have positive disturbance withstand (fault ride-through capability)	✓·	✓·	✓·
Can contribute to system inertia		✓ B	✓·
Can contribute to fast frequency response (FFR)	✓·	✓·	
Can contribute to primary frequency response	✓·	✓·	✓·
Can support a power system island with supply balancing and secondary frequency response	✓·	✓·	✓·
Can initiate or support system restoration	✓ C	✓·	✓·

A. Synchronous machines can usually contribute to system strength much more than IBR due to their higher overload capacity.
B. A grid-forming inverter system requires energy storage to deliver inertia.
C. A grid-following inverter can support but not initiate system restoration.

As inverters exhibit new capabilities, new terminology has been developed to describe specific uses of inverters to provide specific services:

- **Virtual synchronous machines (VSMs)** – VSMs or synchronverters are inverters that mimic the capability of synchronous machines by providing 'synthetic inertia' by rapidly altering their 'electrical torque' (active power) output to respond to the change in frequency. VSMs are grid-forming inverters, because they use their internal frequency and voltage to remain stable while performing inertia responses.
- **Virtual transmission lines (VTLs)** – VTLs are grid-scale storage solutions that are capable of supplying or absorbing power at appropriate times to prevent the thermal overloading of sections of the network, and may be used to defer augmentations in the transmission network (see **Figure 29**). VTLs can be either grid-forming or grid-following, depending on local stability requirements.

Figure 29 Conceptual representation of virtual transmission line

8.3.2 Hydrogen technologies

Hydrogen use impacts the transmission network as both a load during production and a source when used for generation. **Table 20** provides a summary of how hydrogen electrolyser production and fuel cell/turbine generators can contribute to the transmission network. Traditional chemical methods of producing hydrogen have been omitted, but would behave as a traditional refinery load.

While all the hydrogen technologies listed in Table 20 have been developed, tested, and proven, there are currently no grid-scale applications in service in the world.

Table 20 Summary comparison of hydrogen technologies

Service/Capability	Hydrogen electrolyser	Hydrogen fuel cell [A]	Hydrogen turbine
Technology type	Load	Generator	Generator
Can contribute to system strength		✓	✓
Can have positive disturbance withstand (active power oscillation damping)		✓	✓
Can have positive disturbance withstand (fault ride-through capability)		✓	✓
Can contribute to system inertia		✓ [B]	✓
Can contribute to fast frequency response (FFR)	✓ [C]	✓ [B]	
Can contribute to primary frequency response	✓ [C]	✓ [B]	✓
Can support a power system island with supply balancing and secondary frequency response		✓	✓
Can initiate or support system restoration		✓	✓

A. Hydrogen fuel cell assumed to be connected via grid-forming inverter.
B. Hydrogen fuel cell can only provide response by rapidly changing level of power output, it cannot absorb energy.
C. Hydrogen electrolyser can only provide response by rapidly changing level of load, it cannot produce energy.

It is possible for hydrogen production and hydrogen generation processes to be coupled together to form a storage system, in a similar manner to pumped hydro storage.

Currently there is no large renewable hydrogen production facilities in Victoria, however the Victorian Government has produced a renewable hydrogen plan[110] that provides an outlook into how the hydrogen industry and economy will develop in Victoria.

8.3.3 Storage and batteries

Storage technologies can absorb electrical energy from the network and release the energy back into the network at another time. Grid-scale storage technologies include:

- Batteries (such as lithium ion).
- Redox flow batteries.
- Pumped hydro.
- Compressed air storage.
- Gravity storage.
- Flywheels (very short duration mechanical storage).
- Hydrogen (if hydrogen is electrolysed then stored).

[110] See https://www.energy.vic.gov.au/renewable-energy/renewable-hydrogen.

Batteries are expected to be the most used long-term storage technology, because they do not require specific geological conditions, use technology that is already available, and potentially can be relocated if storage needs change.

The Victorian Government has set storage targets for Victoria that are to be legislated[111]:

- At least 2.6 GW of energy storage capacity by 2030.
- At least 6.3 GW by 2035.

There are four main applications for storage in the transmission network – some storage installations may be used in more than one application, through reservation of capacity:

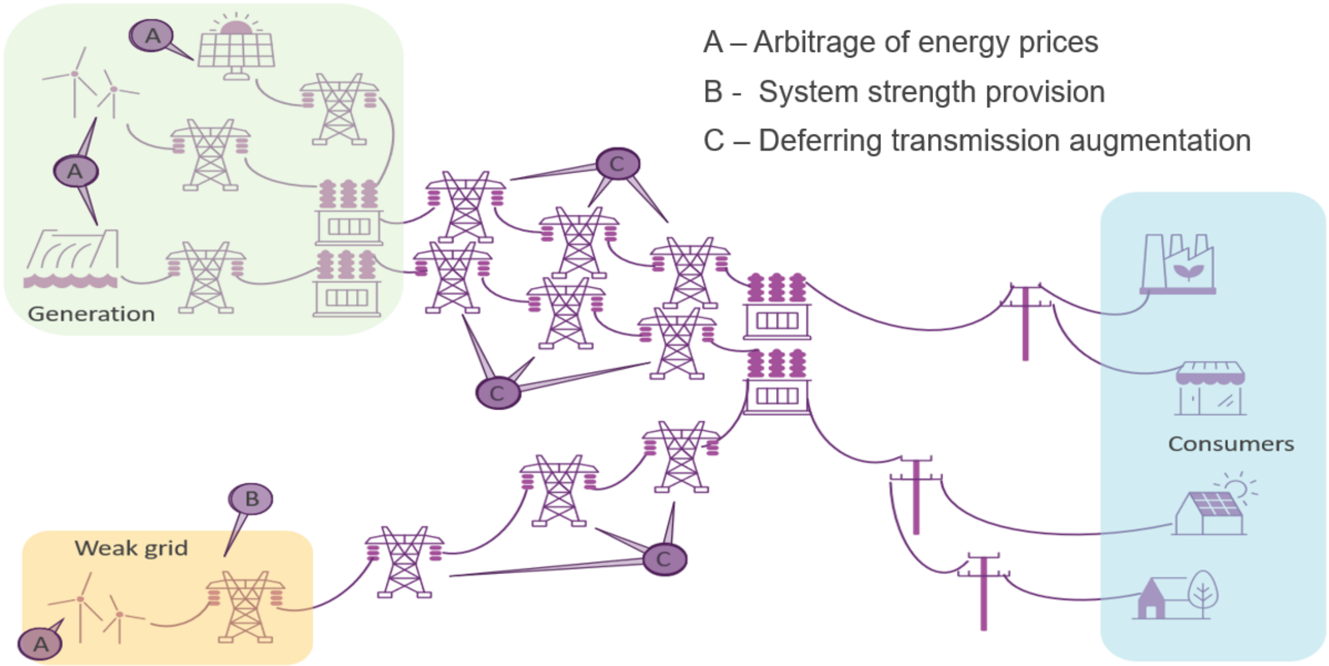
- **Arbitrage of energy prices** – this is typically done by third parties who are charging during times when energy is cheap and discharging during times when energy is expensive. While a battery for this purpose will not become part of the DSN, it is currently the most common use for batteries, and a battery being used for this application may be used for other applications.
- **Frequency control ancillary services (FCAS) –** this type of storage is typically located at or close to a regional reference node. Its role is to frequently charge and discharge small amounts of energy to provide support to the network frequency by balancing supply and demand in the network.
- **System strength provision** – this type of storage is used to rapidly absorb or supply power to address a network contingency by providing fault current or supporting frequency or voltage. Storage used for system strength provision will be located in weaker parts of the network. Batteries used for system strength will need to be maintained at a level with sufficient capacity to absorb and provide power when a network event occurs. For capacity reserved to provide this service, charging and discharging is only expected to take place during a network event and after an event to restore storage levels[112].
- **Deferring network augmentations** – this type of storage is used to alleviate a constrained part of the network at a time when equipment may exceed its limits. Typically, this type of storage is located upstream or downstream of the constraint or in a location that will change network power flows to divert flow away from the constraint. Batteries used to defer network augmentations would normally be maintained at either empty or full level, depending on the constraint they are addressing. Charging and discharging is expected to be infrequent, because constraints are typically for short periods and often seasonal.

Figure 30 shows the type of network locations where these storage applications could be used, and **Table 21** provides a summary comparison of the different applications.

[111] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets#:~:text=Victoria%E2%80%99s%20energy%20storage%20targets%20will%20be%20legislated.%20They,also%20to%20be%20supplied%20through%20longer%20duration%20imbalances.

[112] When providing system strength services consideration needs to be given to prevent excessive provision of inertia in weak grids

Figure 30 Locations where different types of storage could be used in the transmission network



Like using batteries for deferring transmission augmentations, regional reference nodes where FCAS support may be are at specific locations in the network. These nodes can change from time to time and not all will require FCAS support. Reference nodes requiring support are most likely to occur near weak grids

Table 21 Summary comparison of storage applications

Use case	Arbitrage of energy prices	FCAS	System strength provision	Deferring transmission augmentation
Long or short term storage?	Short for intraday Long for seasonal	Typically short-term	Either	Typically short-term
Location	Near generators or Regional Reference Node	Near regional reference node	Weak networks	Constraint-specific
Energy storage capacity required (MWh)	High	Low	Low	High
Charge/discharge frequency	Often – driven by price	Frequently charging/discharging small amounts FCAS does not use full depth of energy storage	May use the full energy storage capacity for other services but reserve a very small (<1%) energy buffer	If for a contingency event, no charge/discharge If for shifting peaks then daily charge/discharge

A1. Victorian interconnector performance

Table 22 and **Table 23** summarise trends in Victoria's exports to other regions across the interconnectors. Since the closure of Hazelwood Power Station in 2017, there has been a significant reduction in the quantity and time Victoria has exported power to neighbouring mainland regions.

A reversal of this trend was observed in 2020-21, and has continued, with net exports from Victoria into neighbouring regions increasing year on year. In 2022-23, while total net exports were greater than the previous year, this was driven by a significant increase in export to Tasmania. Net exports to all other neighbouring regions actually declined slightly.

Table 22 Percentage (%) of time interconnector is exporting energy from Victoria

Interconnector	5-year average before Hazelwood closure in 2017	2018-19	2019-20	2020-21	2021-22	2022-23
VNI	84%	50%	56%	71%	80%	71%
Heywood	82%	42%	37%	47%	52%	51%
Murraylink	46%	50%	63%	63%	67%	68%
Basslink	44%	42%	44%	58%	49%	67%
Victoria (net)	**87%**	**50%**	**50%**	**72%**	**81%**	**81%**

Table 23 Net energy exported from Victoria (gigawatt hours [GWh])

Interconnector	5-year average before Hazelwood closure in 2017	2018-19	2019-20	2020-21	2021-22	2022-23
VNI	4,032	953	1,174	2,338	3,361	2787
Heywood	1,824	-388	-534	-117	232	99
Murraylink	48	-36	152	289	468	432
Basslink	-533	-496	-512	611	-279	929
Victoria (net)	**5,371**	**33**	**279**	**3,122**	**3,782**	**4,247**

Figure 31 Victoria net interconnector flow duration curve (all interconnectors)

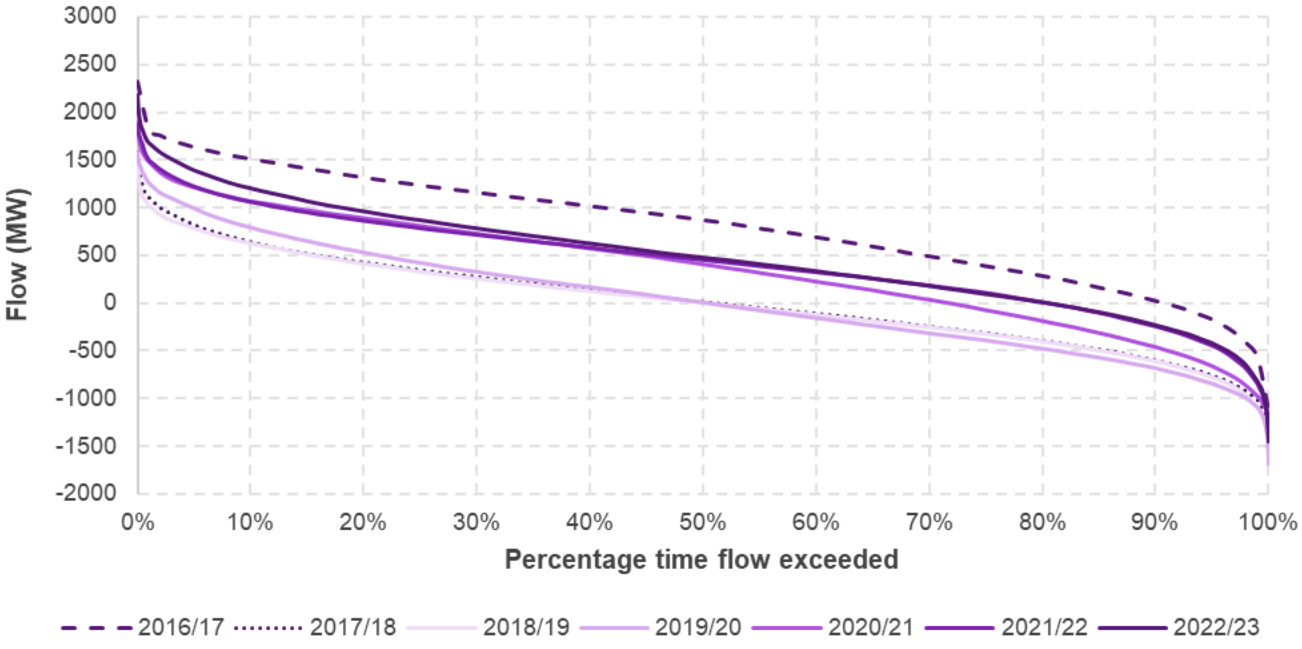


Figure 32 Historical binding hours for exporting along VNI by constraint types, From 2017-18 to 2022-23

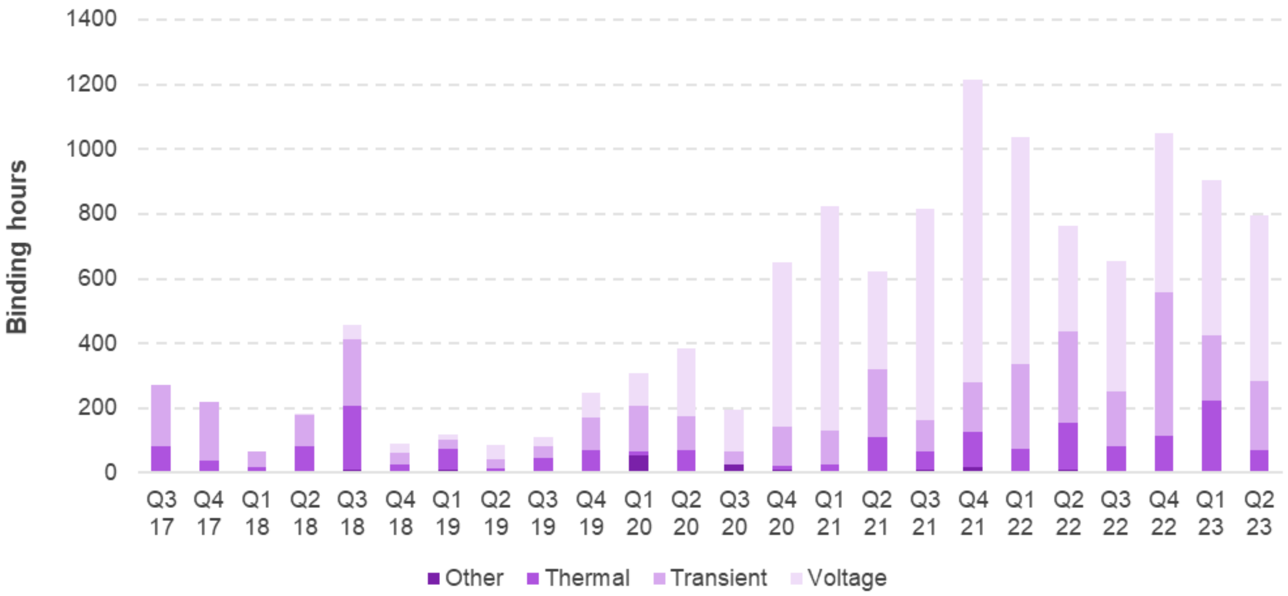
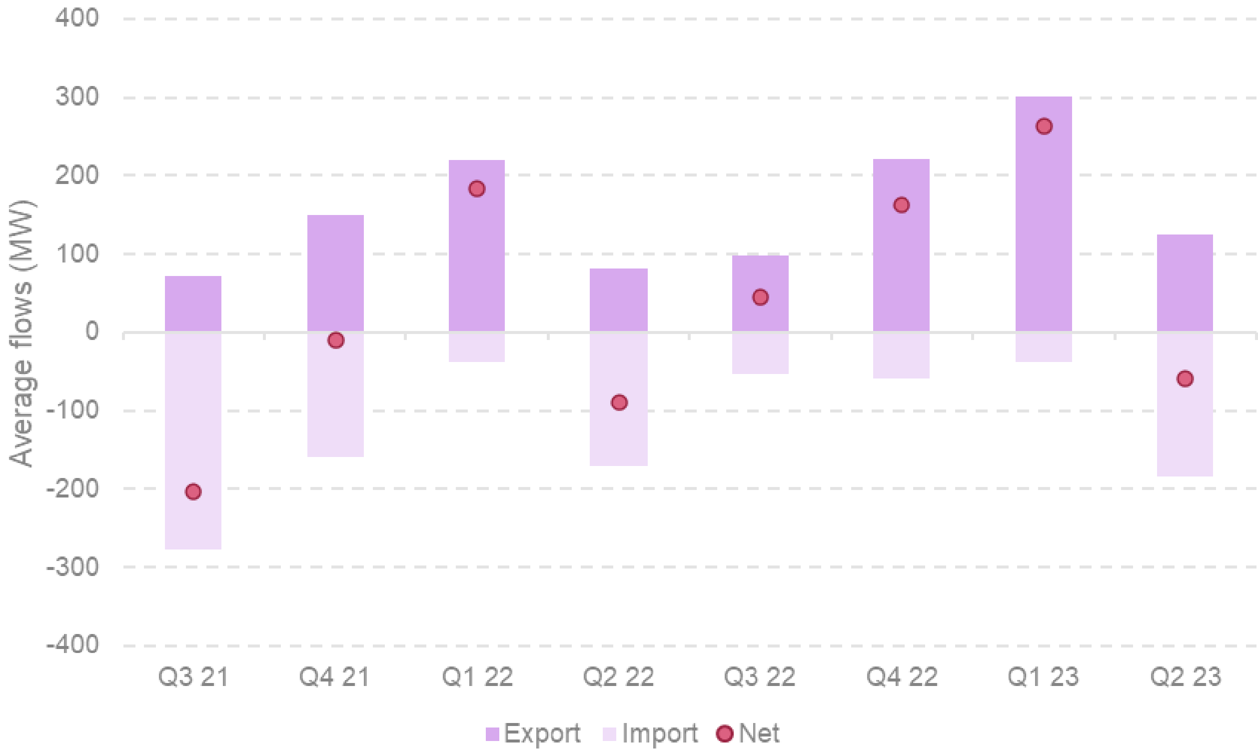


Figure 33 Quarterly average Basslink flows (MW) in 2021-22 and 2022-23



A2. DSN performance in 2022-23 at times of high stress

A2.1 Demand snapshots

Table 24 compares the overarching DSN conditions during each operational demand snapshot.

Table 24 Summary of operating conditions for maximum and minimum demand in Victoria

Characteristic	Maximum demand	Daytime minimum demand	Night-time maximum demand
Date and time	17/01/2023 18:00	18/12/2022 13:00	05/02/2023 04:30
Victorian operational demand	8,988 MW	2,195 MW	3,602 MW
Distributed PV	353 MW	2,725 MW	0 MW
Net power flow into Victoria via interconnectors*	19 MW • 30 MW from NSW • 172 MW to SA • 161 MW from TAS	-817 MW • 268 MW to NSW • 72 MW to SA • 477 MW to TAS	-1609 MW • 669 MW to NSW • 605 MW to SA • 336 MW to TAS
Victorian renewable generation	3,582 MW, representing 41% of Victorian generation, consisting of: • 1,882 MW of wind • 313 MW of solar • 1,387 MW of hydro	515 MW, representing 16% of Victorian generation, consisting of: • 349 MW of wind • 166 MW of Solar • 0 MW of hydro	798 MW, representing 15% of Victorian generation, consisting of: • 420 MW of wind • 0 MW of solar • 378 MW of hydro
Victorian synchronous generation	6,598 MW, representing 75% of Victorian generation, consisting of: • 4,293 MW of coal • 918 MW of gas • 1,387 MW of hydro	2,634 MW, representing 84% of Victorian generation, consisting of: • 2,634 MW of coal • 0 MW of gas • 0 MW of hydro	4,721 MW, representing 91% of Victorian generation, consisting of: • 4,343 MW of coal • 0 MW of gas • 378 MW of hydro
Temperature at Melbourne Airport	34.5° C	21.8° C	11.8° C

*These are the measured flows during each snapshot and may differ from the interconnector's dispatch target.

A2.1.1 Daytime minimum demand snapshot

The daytime minimum demand snapshot captures conditions under which voltage control may prove challenging, as lightly loaded lines charge voltages towards the high end of their operating limits. Distributed and large-scale solar generation is typically at close to maximum generation under these conditions. With increasing distributed generation, daytime minimum demand has dropped each year to record low levels (see Section 3.3.1).

During low demand in Victoria, operators have historically been required to take action to manage high voltages (see Section 3.4.3). The unavailability of conventional generators to absorb the excess reactive power during low demand periods, can result in high post-contingency voltages across the 220 kV Metropolitan Melbourne network (such as Keilor), and the Victorian regional network (such as Eildon, Mt Beauty, Berrybank, and Terang).

Figure 34 shows a heat map of post-contingent voltages across Victorian 500 kV terminal stations for a critical contingency. Voltages are highest in and around the metropolitan load centres (like Rowville and Cranbourne).

Keilor Terminal Station typically sets the requirement for high voltage management, as its emergency high voltage rating is lower than other 500 kV terminal stations.

Due to the installation of two 100 MVAr reactors at Moorabool in July and August 2022, the high voltage at Moorabool and Haunted Gully has improved compared to last year's minimum demand case.

Figure 34 Heat map of post-contingent voltages at 500 kV terminal stations for the loss of a Loy Yang unit during minimum demand

The snapshot is based on power system characteristics observed at 13:00 on 18 December 2022. At this time every interconnector except Heywood was exporting at its limit:

- Murraylink was exporting towards South Australia at its limit, which was set by a thermal constraint avoiding overloading in northeast South Australia.
- VNI East was overall exporting at its limit, which was set by a system normal voltage collapse constraint for the trip of any major 220 kV line in North West Victoria.
- Basslink was also exporting towards Tasmania at its limit, set by the system normal FCAS constraints.

A2.1.2 Night-time minimum demand

The night-time minimum demand scenario is characterised by low wind, no solar, and a significant proportion of synchronous generation – quite different to the lowest minimum demand, which usually occurs in the middle of the day.

The lowest night-time operational demand in 2022-23 was 3,602 MW, which was 1,407 MW higher than the annual minimum demand that occurred in the daytime. The difference between daytime minimum demand and night-time minimum demand is increasing every year as night-time minimum demand stays the same whilst daytime minimum demand continues declining, reflecting the uptake of distributed PV.

Figure 35 shows a heat map of post-contingent voltages across Victorian 500 kV terminal stations for a critical contingency. The post-contingent voltages across the 500 kV network are higher than or equal to those of the annual minimum demand snapshot.

Figure 35 Heat map of post-contingent voltages at 500 kV terminal stations for the loss of a Loy Yang unit during night-time minimum demand

The snapshot is based on power system characteristics observed at 04:30 on 5 February 2023. At this time:

- Victoria was exporting to South Australia through both Murraylink and the Heywood interconnector. Export through Heywood was limited by the system normal FCAS.
- VNI East export towards New South Wales was approaching its limit, set by the transient stability constraints for the trip of the Hazelwood – South Morang 500 kV line.
- Basslink was also exporting towards Tasmania, limited by the system normal FCAS constraints.

A2.2 High renewable snapshots

A2.2.1 High wind snapshot

Wind generation in Victoria is primarily located in the V3 Western Victoria and V4 South West Victoria REZs. Typically wind generation from the two REZs is coincidental due to their geographical proximity. Maximum wind generation for 2022-23 in Victoria occurred at 21:00 on 8 June 2023.

Table 25 Summary of operating conditions for maximum wind generation in Victoria

Characteristic	Maximum demand
Date and time	08/06/2023 21:00
Victorian operational demand	6,208 MW
Distributed PV	0 MW
Net power flow into Victoria via interconnectors*	-1,084 MW

Characteristic	Maximum demand
	• 830 MW to NSW • 305 MW to SA • 51 MW from TAS
Victorian renewable generation	3,731 MW, representing 52% of Victorian generation, consisting of: • 3,638 MW of wind • 0 MW of Solar • 93 MW of hydro
Victorian synchronous generation	3,540 MW, representing 49% of Victorian generation, consisting of: • 3,447 MW of coal • 0 MW of gas • 93 MW of hydro
Temperature at Melbourne Airport	12.9° C

* These are the measured flows during each snapshot and may differ from the interconnector's dispatch target.

Victorian wind generation saw a 27% (289 MW) lift in average output, compared to 2021-22, with a large increase in available capacity from new and recently connected facilities in Q2 2023[113]. Due to the commissioning of new wind farms in Victoria (such as Mortlake South and Berrybank 2), overall wind generation increased by 800 MW compared to the last year's high wind snapshot. At the time of maximum wind, 1,985 MW (55%) of Victorian wind generation was supplied from the V4 South West Victoria REZ, and 1,516 MW (42%) of Victorian wind generation was supplied from the V3 Western Victoria REZ.

Figure 36 shows the pre-contingent (actual) loading and post contingent loading (expected)[114] and power flows across the 220 kV West Murray network for loss of the critical contingencies, Horsham to Murra Warra to Kiamal and Red Cliffs to Wemen to Kiamal. It shows that at the time of maximum wind generation, the Ararat to Waubra, Waubra to Ballarat, Ballarat to Bendigo and Elaine to Moorabool lines were operating at their post-contingent thermal limits.

This snapshot occurred at night when the thermal ratings of these critical lines were high due to the low temperatures (12.9°C at Melbourne Airport). During higher temperatures when the line ratings are lower, it is likely that these thermal constraints would have been more limiting and wind generation in Western Victoria constrained. WRL (see Section 4.1.2) will reduce instances when generation is limited by the Ararat to Waubra to Ballarat and Elaine to Moorabool 220 kV lines, while VNI West will reduce instances when generation is limited by the Ballarat – Bendigo 220 kV line in Western Victoria.

[113] See QED Q2 2023, at https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q2-2023-report.pdf?la=en&hash=719538BE6166CB79BE1BF6B9BE82A183.

[114] Based on power system modelling.

Figure 36 West Murray flows and loading, pre-contingent (left), post-contingent for loss of Horsham – Murra Warra – Kiamal (middle), post-contingent for loss of Red Cliffs – Wemen – Kerang (right)

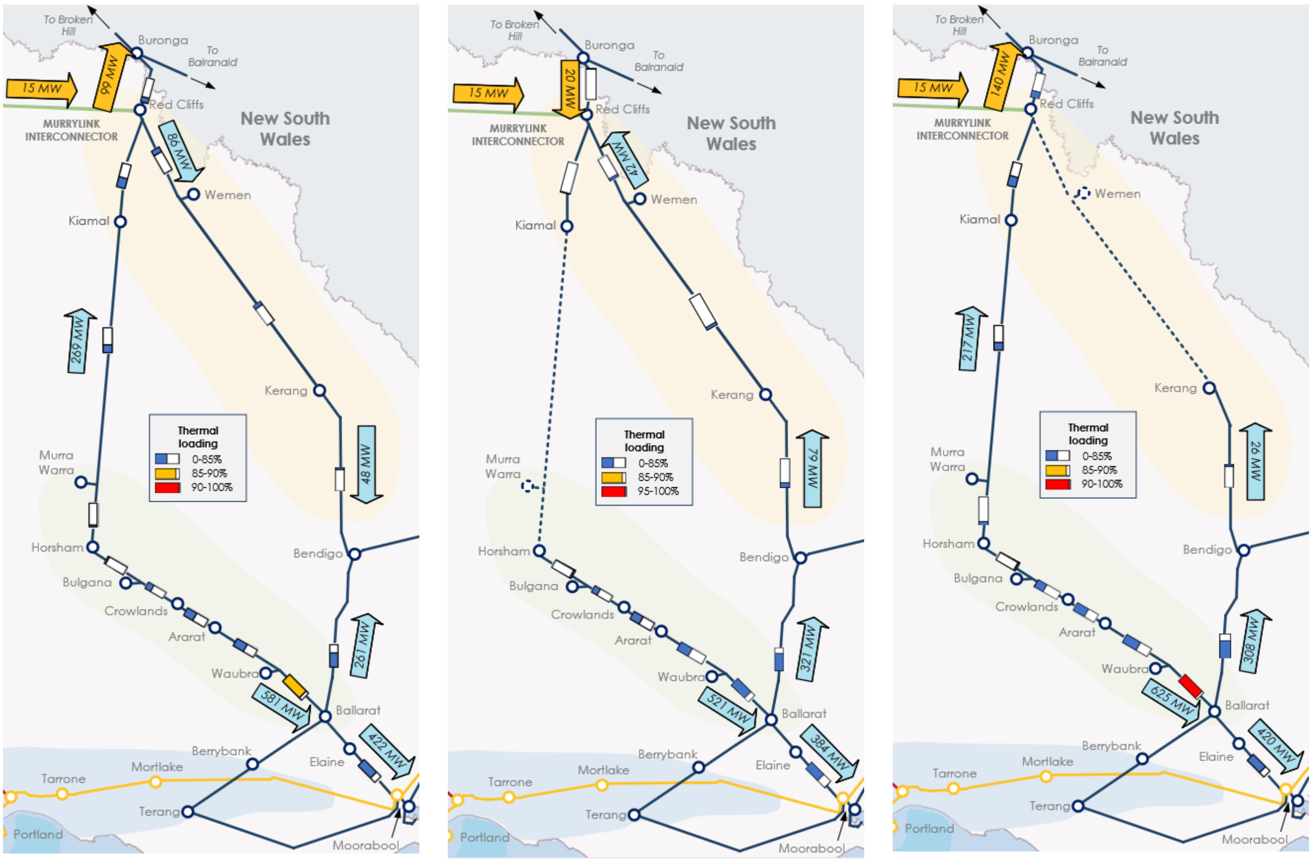


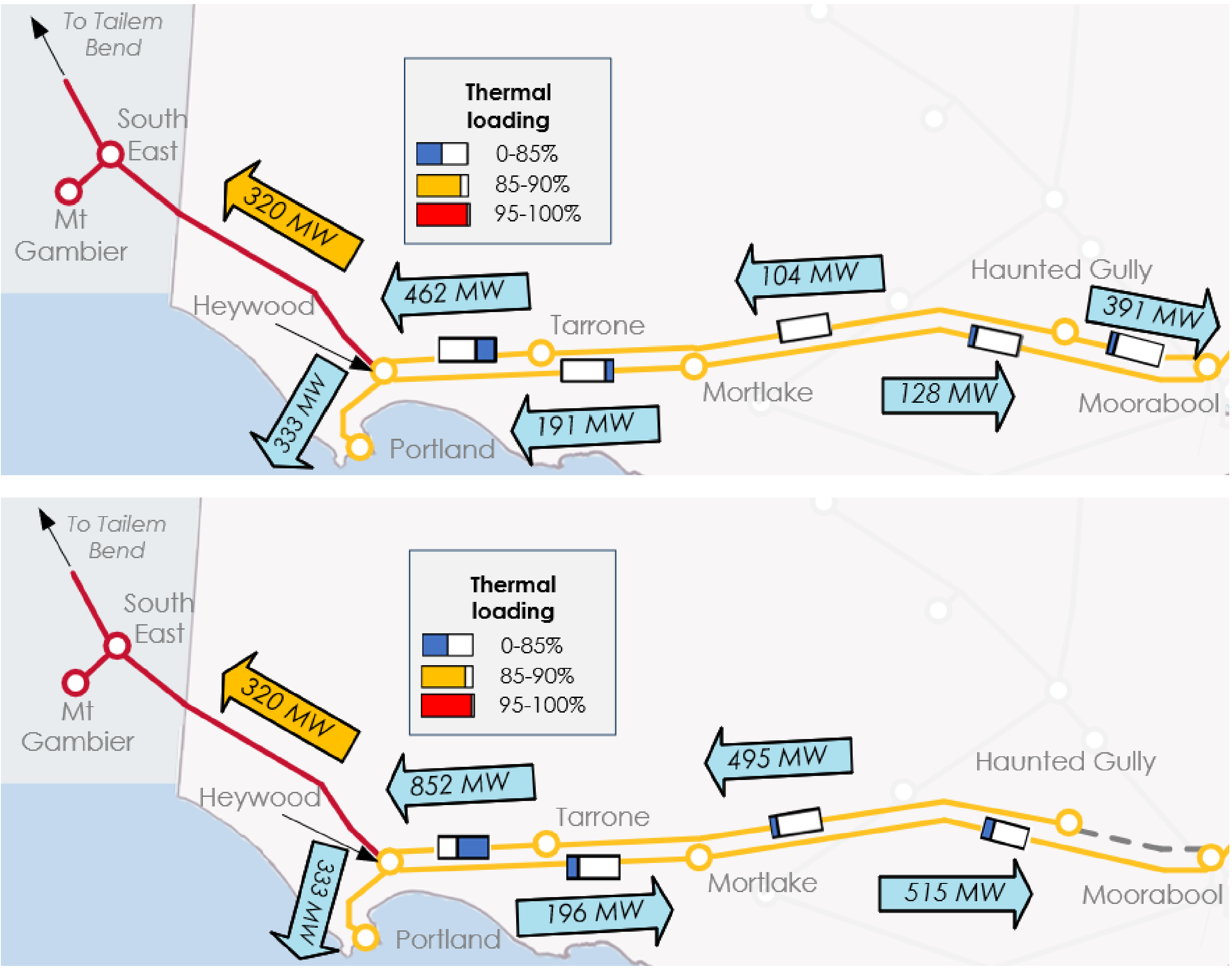
Table 26 Post-contingent flows from Western Victoria and Murray REZs for the loss of Ballarat – Moorabool 220 kV Line 2

Limiting constraint	220 kV lines of interest	% loading	MW flows
V>>NIL_ELML_BAML2	Waubra - Ballarat	84%	574
	Ararat - Waubra	49%	439
	Murra Warra - Kiamal	33%	278
	Red Cliffs - Buronga	44%	262
	Red Cliffs - Wemen	21%	85
	Ballarat - Bendigo	68%	284
	Elaine – Moorabool	96%	556
	Ballarat – Moorabool Line 1	83%	347

Loss of Red Cliffs to Buronga also causes a post-contingent flow of 622 MW on the Waubra to Ballarat line, resulting in a loading of 92% of rating. A thermal constraint limits the flow on the Elaine to Moorabool line for the loss of Ballarat to Moorabool 220 kV Line 2. Details of this post contingent situation are in Section 5.5.1.

As shown in **Figure 37**, wind generation in the South West Victoria 500 kV network (V4 REZ) operated without impact from network constraints at this period, but as new generation continues to connect in this area, both thermal and voltage collapse limitations will begin to restrict local generation (see Section 5.5.2, V4 South West Victoria).

Figure 37 500 kV flows and loadings V4 Southwest Victorian pre-contingent (above) and post-contingent (below) for Haunted Gully to Moorabool



A2.3 High export snapshots

A2.3.1 Maximum VNI export snapshot

VNI typically exports more often than it imports, and exports are currently most constrained by voltage collapse constraints (see Section 3.5). The high export snapshot summary in **0** shows network operating conditions when VNI exports were highest.

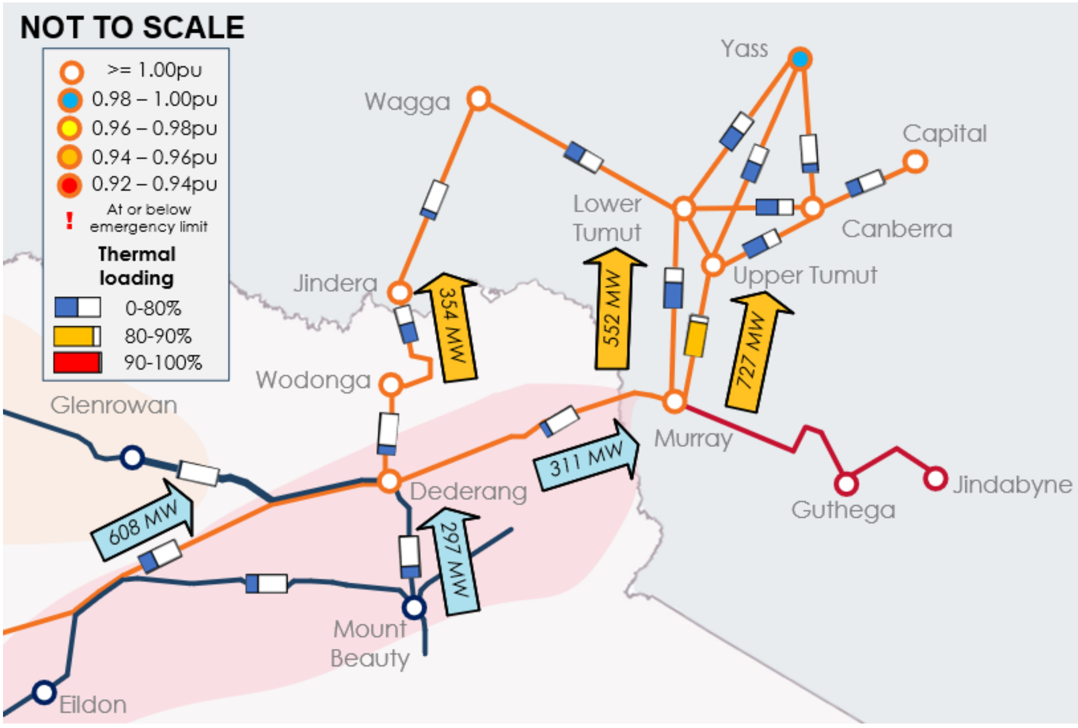
Table 27 Summary of Victoria maximum export snapshot

Characteristic	Maximum demand
Date and time	27/06/2023 22:00
Victorian operational demand	6,236 MW
Distributed PV	0 MW
Net power flow into Victoria via interconnectors*	-1,907 MW • 1,714 MW to NSW • 563 MW to SA • 370 MW from TAS
Victorian renewable generation	3,291 MW, representing 40% of Victorian generation, consisting of • 1,968 MW of wind • 0 MW of Solar • 1,323 MW of hydro
Victorian synchronous generation	6,109 MW, representing 77% of Victorian generation, consisting of- • 4,786 MW of coal • 0 MW of gas • 1,323 MW of hydro
Temperature at Melbourne Airport	10.1° C

*These are the measured flows during each snapshot and may differ from the interconnectors' dispatch target.

The VNI maximum export snapshot assesses the network conditions at 22:00 on 27 June 2023, when VNI was dispatched at 1,714 MW. **Figure 38** below shows the flows, loading and voltages across the VNI Eastern corridor during the maximum export snapshot.

Figure 38 Maximum export flows, loading and voltages in the VNI Eastern corridor



A3. Approach to network limitation review

In assessing the impact of limitations, AVP considers information from power system performance analysis and market simulations each year for the next 10 years regarding:

- The percentage n and n–1 loadings of transmission plant associated with the network loading limitation, based on the continuous and short-term ratings respectively.
- The load and energy at risk. Load at risk is the load shedding required to avoid the network limitation.
- Expected USE, which is the energy at risk after accounting for forced outages.
- Dispatch cost, which is the additional cost from constraining generation.
- Limitation cost, which is the total additional cost due to both constraining generators and expected USE.

Power system performance analysis uses conservative assumptions for demand, temperature, and wind speed to capture as many network limitations as possible for market simulation. For this reason, DSN performance analysis results (that is, the percentage loadings) can show more severe impacts than market simulations. AVP derives forecast transmission plant loadings using load flow simulations, and develops load flow base cases for these simulations using inputs and assumptions aligned with AEMO's latest IASR wherever possible. Key assumptions and inputs include:

- The 10% POE terminal station demand for maximum demand base cases.
- Historical maximum power transfers for a high Victoria to New South Wales power transfer base case.
- Typical generation dispatch and interconnector flow patterns under the given operating conditions.
- The system normal operational configuration for the existing Victorian transmission network.
- Committed transmission network augmentation and generation projects, and other likely future projects which AVP considers relevant to network limitation review.
- Standard continuous ratings and short-term ratings at 45ºC and 0.6 m/s wind speed.
- Unless indicated, 15-minute ratings for transmission lines. Some transmission lines in Victoria are equipped with automatic load shedding schemes, which avoid overloading by disconnecting load blocks following a contingency. These schemes allow lines to operate to 5-minute ratings.
- AVP bases the market impact of each network limitation on probabilistic market simulations that apply:
- Weighted 50% POE and 10% POE maximum demand forecasts (weighted 70% and 30% respectively).
- Historical wind generation availability, and historical load profiles.
- Dynamic ratings based on historical temperature traces.
- Non-committed new and retired generation.

For more information, see the Victorian Electricity Planning Approach[115].

[115] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2016/Victorian-Electricity-Planning-Approach.pdf.

A4. DSN limitations detail

These details for transmission network limitations are grouped geographically.

The changes in the list of limitations are:

- Change in category:
  - Overload of Moorabool – Geelong for loss of the parallel line due to increased wind generation in V4 South West and V3 Western Victoria REZs and increased demand. This is now considered an emerging limitation, as outlined in Section 5.2.
  - Overload of Ringwood – Thomastown for loss of the Rowville A1 Transformer due to increased demand. This is now considered an emerging limitation, as outlined in Section 5.2.
  - Overload of Rowville A1 500/220 kV transformer under system normal due to increased demand. This is now considered an emerging limitation, as outlined in Section 5.2.
  - Overload of the Geelong – Deer Park or Deer Park – Keilor 220 kV lines due to increased demand at Deer Park. This is now considered a priority limitation, as outlined in Section 5.3
  - Overload of the Geelong – Keilor 220 kV lines due to increased wind generation in V4 South West and V3 Western Victoria REZs and increased demand. This is now considered a priority limitation, as outlined in Section 5.3.
  - Overload of Latrobe Valley corridor – Overloading Hazelwood to Yallourn and Rowville to Yallourn 220 kV lines post Yallourn power station retirement. This is now a priority limitation as outlined in Section 5.3.
- Removed:
  - High RoCoF in SW Vic for a credible separation event during a prior outage.
  - Insufficient reactive support at Deer Park due to increased demand at Deer Park. This will be addressed via the Metropolitan Melbourne Voltage Management RIT-T and consequently is removed.
- Change in costs of potential solutions:
  - All costs are removed because they are under review given the recent significant changes in material and labour costs.

The possible network solutions presented in the sub-sections below should be treated as indicative only, and a RIT-T will be required to determine the full list of network and non-network options as well as the preferred option. The preferred option may include one or a combination of the solutions presented in the sub-sections below. In this appendix, triggers are defined as the operating conditions under which a limitation may result in supply disruptions or constrain generation at increased frequency. A trigger being met will not necessarily result in any augmentations as that would be subjected to a RIT-T or appropriate consideration.

A4.1 Central North REZ

Table 28 Limitations in the Central North REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Dederang – Glenrowan – Shepparton – Bendigo 220 kV **and** **Dederang – Shepparton 220 kV line loading**	Monitored	• Install an automatic load shedding and generation runback control scheme to enable the use of five minute line rating. • Install a wind monitoring scheme. • Install a modular flow controller on the Bendigo – Fosterville – Shepparton 220 kV line. • Replace existing Dederang – Shepparton and Shepparton – Bendigo 220 kV line with new double circuit lines.	Increased demand in regional Victoria and/or increased import from New South Wales. Large-scale new generation connected to Western Victoria area, and congestion within Western Victoria relieved to allow the new generation to be sent out of Western Victoria.	Identified limitation as part of Central North Victoria REZ	Any new transformer or new transmission lines are likely to be contestable projects.

A4.2 Eastern Corridor

Table 29 Limitations in the Eastern Corridor

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Thermal limitations in Latrobe Valley 220 kV corridor – Overloading Hazelwood to Yallourn and Rowville to Yallourn 220 kV lines post Yallourn retirement.	Priority	• AVP has identified a new switching arrangement at HWPS (modified parallel mode) for post Yallourn retirement to utilise the eastern 220 kV corridor. • AVP will initiate a minor augmentation project to scope out the details of the works required to facilitate the proposed re-configuration in year 2028. The scope may include minor switching works at HWPS and implementation of a control scheme to manage post contingent overloading.	Decommissioning of Yallourn power station with modified parallel mode or additional generation is commissioned on the 220kV network a HWPS, at a site east of HWPS or on the 500 kV network east of CBTS.	Not identified	Works to reconfigure HWPS are unlikely to be contestable
Hazelwood – Loy Yang 500 kV line loading	Monitored	• Construct a new single circuit Hazelwood – Loy Yang 500 kV line. • Construct a new double circuit Hazelwood – Loy Yang 500 kV and string only one circuit. • Construct a new double circuit Hazelwood – Loy Yang 500 kV and string both.	Commissioning of additional generation connected at Loy Yang Power Station.	Identified in 2020 ISP	Any new line is likely to be competitively sourced

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Hazelwood – Loy Yang 500 kV line outage window	Monitored	• Construct a new single circuit Hazelwood – Loy Yang 500 kV line. • Construct a new double circuit Hazelwood – Loy Yang 500 kV and string only one circuit. • Construct a new double circuit Hazelwood – Loy Yang 500 kV and string both. • System strength and reactive power services to reduce reliance on Loy Yang units for these services during low demand periods.	Reduction in dispatchable capacity west of Hazelwood 500kV. Higher and more frequent demands above 6000 MW.	Not identified	Any new line is likely to be competitively sourced

A4.3 Northern Corridor

Table 30 Limitations in the Northern Corridor

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Dederang – Mount Beauty 220 kV line loading	Monitored	• Install a wind monitoring scheme. • Up-rate the conductor temperature of both 220 kV circuits between Dederang and Mount Beauty to 82ºC.	Increased demand in Metropolitan Melbourne or increased export to New South Wales with high hydro generation in the area	Not identified as a material limitation in the scenarios modelled	If needed, these are unlikely to be contestable projects
Mount Beauty – Eildon – Thomastown 220 kV line loading	Monitored	• Install wind monitoring scheme • Up-rate Mount Beauty - Eildon – Thomastown 220 kV line, including terminations to 75 ºC operation.	Increased New South Wales import and export.	Not identified as a material limitation in the scenarios modelled.	If needed, this is unlikely to be a contestable project.
Dederang 330/220 kV transformer loading	Monitored	• Install a fourth 330/220 kV transformer at Dederang (or a newly established station nearby).	At times of over 2,500 MW of imports from New South Wales and Murray generation (with the DBUSS transformer control scheme being active)	Not identified as a material limitation in the scenarios modelled.	Any new transformer is likely to be a contestable project
Voltage stability at North Victoria/ South New South Wales (import)	Monitored	• Procure network support services, including the provision of additional reactive support (generating). • Install additional capacitor banks and/or controlled series compensation at Dederang and Wodonga terminal stations	Increased import from New South Wales to Victoria (high demand in Victoria)	Not identified as a material limitation in the scenarios modelled.	If needed, these are both likely to be contestable projects

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Voltage stability at North Vic/South New South Wales (export)	Monitored	• Procure network support services • Install an SVC or a STATCOM.	Increased export to New South Wales from Victoria under minimum demand in Victoria	Constraint identified during high export to New South Wales	If needed, these are both likely to be contestable projects.
Murray – Dederang 330 kV line loading	Monitored	• Install third 1,060 MVA 330 kV line between Murray and Dederang (or a newly established station nearby). • Install second 330 kV line from Dederang (or a newly established station nearby) to Jindera	Increased import from New South Wales to Victoria or Murray generation	Not identified as a material limitation in the scenarios modelled.	If needed, these are both likely to be contestable projects.

A4.4 Murray River REZ

Table 31 Limitations in the Murray River REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Voltage oscillation in western and north-west Victoria (under prior outage)	Monitored	• NMAS contracts to provide system strength. • Install automatic generation runback control schemes.	Increased probability of prior outages of local 220 kV transmission lines. Reduced system strength in the region.	Constraint identified during high solar generation and prior outage.	Any solutions are likely to be contestable projects.
Red Cliffs – Wemen – Kerang – Bendigo 220 kV line loading (high generation)	Monitored	• Replace the existing Bendigo – Kerang – Wemen – Red Cliffs 220 kV line with a new double circuit 220 kV circuit line and establish associated new terminal stations or existing station augmentations.	Increased generation in Regional Victoria	Identified as limitation as part of Murray River REZ	Any solutions are likely to be contestable projects.
Voltage instability/collapse in North West Victoria (around Wemen Terminal Station)	Monitored	• NMAS contract for the use of spare reactive power capacity. • Install dynamic voltage regulation such as SVC.	Low local demand and high solar generation.	This was not identified as a limitation as it is a localised issue.	Any solutions are likely to be contestable projects
Red Cliffs – Wemen – Kerang – Bendigo 220 kV line loading (high demand)	Monitored	• Install an automatic load shedding control scheme to enable the use of five minute line rating. • Replace the existing Bendigo – Kerang – Wemen – Red Cliffs 220 kV line with a new double circuit 220 kV circuit line and establish associated new terminal stations or existing station augmentations.	Increased demand in Regional Victoria.	Not identified as limitation as it is a localised issue.	Any solutions are likely to be contestable projects.

A4.5 South West Victoria REZ

Table 32 Limitations in the South West Victoria REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Ballarat – Berrybank – Terang – Moorabool 220 kV line loading	Monitored	• Install automatic generation runback control schemes. • Replace the existing Ballarat – Berrybank – Terang – Moorabool 220 kV line with a new double circuit 220 kV circuit line.	Increased generation in regional Victoria	Identified as limitation as part of South West Victoria REZ.	Solutions are likely to be contestable projects.
Moorabool – Heywood – Portland 500 kV line voltage unbalance	Monitored	• A switched capacitor with individual phase switching at Heywood or near Alcoa Portland. • Install phase switched power flow controllers at Heywood or near Alcoa Portland. • An SVC or a STATCOM. • Additional transposition towers along the Moorabool – Heywood – Alcoa Portland 500 kV line.	New generation connections along the Moorabool – Heywood –Alcoa Portland 500 kV line potentially introduce voltage unbalance along the line. The impact of voltage unbalance levels increases in proportion to power flow, new generation connection points, and output generated.	Limitation not found as part of 2022 ISP/2022 NSCAS as it is related to voltage quality.	Switched capacitor and static VAr options are likely to be contestable projects. Line transposition is unlikely to be a contestable project.
Inadequate south-west Melbourne 500 kV thermal capacity	Monitored	• A new Moorabool – Mortlake/Tarrone – Heywood 500 kV line. • Line limiting plant upgrades. • Install wind monitoring dynamic line rating scheme.	Significant wind generation and/or gas generation (in addition to the existing generation from Mortlake) is connected to the transmission network in the South-West Corridor.	Identified as a limitation in 2020 ISP South West Victoria REZ Scorecard.	Any new line is likely to be a contestable project
Moorabool 500/220 kV transformer loading	Monitored	• Transformer limiting plant upgrade. • Install an automatic generation runback control scheme. • Install third Moorabool 500/220 kV transformer.	Large-scale new generation connected to western Victoria area, and congestion in western Victoria relieved to allow the new generation to be sent out of western Victoria	Not identified as a material limitation in the scenarios modelled.	Any new transformer is likely to be a contestable project.
Voltage collapse in South West Victoria	Monitored	• Cut in Haunted Gully – Tarrone 500 kV line at Mortlake to form Haunted Gully – Mortlake – Tarrone 500 kV line • Note: A committed project (RDP stage 1) includes the scope of line cut in at Mortlake to relieve this constraint.	Increased generation on the MLTS – HYTS lines and high import from South Australia.	Not identified.	To be confirmed

A4.6 Greater Melbourne and Geelong

Table 33 Limitations in Greater Melbourne and Geelong

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Ringwood – Thomastown 220 kV line loading	Emerging	• Upgrading the Thomastown – Ringwood 220 kV line by rebuilding as a double circuit. • Cut in Rowville – Ringwood – Thomastown 220 kV at Templestowe and Rowville – Templestowe – Thomastown 220 kV at Ringwood to form the Rowville – Ringwood – Templestowe – Thomastown No. 1 and No. 2 circuits plus any fault level mitigation work. • New (third) 500/220 kV transformer at Rowville, plus any fault level mitigation works. • Establish a new 500kV switch yard at Templestowe cutting into the existing South Morang – Rowville No. 3 500kV line and a new 500/220 kV transformer at Templestowe terminal station, plus any fault level mitigation works. • Establish a new 500kV switch yard at Ringwood cutting into the existing South Morang – Rowville No. 3 500kV line and a new 500/220 kV transformer at Ringwood terminal station, plus any fault level mitigation works.	Increased demand in Eastern Metropolitan Melbourne. Reduced supply from Eastern Victoria and increased supply from Western Victoria.	Not identified as it is a localised issue	Any line cut-in is unlikely to be a contestable project. Any new transformer is likely to be a contestable project.
Templestowe – Thomastown 220 kV line loading	Monitored	• Cut in Rowville – Ringwood – Thomastown 220 kV at Templestowe and Rowville – Templestowe – Thomastown 220 kV at Ringwood to form the Rowville – Ringwood – Templestowe – Thomastown No. 1 and No. 2 circuits plus any fault level mitigation work. • New (third) 500/220 kV transformer at Rowville, plus any fault level mitigation works. • Establish a new 500kV switch yard at Templestowe cutting into the existing South Morang – Rowville No. 3 500kV line and a new 500/220 kV transformer at Templestowe terminal station, plus any fault level mitigation works. • Establish a new 500kV switch yard at Ringwood cutting into the existing South Morang – Rowville No. 3 500kV line and a new 500/220 kV transformer at Ringwood terminal station, plus any fault level mitigation works.	Increased demand in Eastern Metropolitan Melbourne. Reduced supply from Eastern Victoria and increased supply from Western Victoria.	Not identified as it is a localised issue	Any line cut-in is unlikely to be a contestable project. Any new transformer is likely to be a contestable project.

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Rowville – Malvern 220 kV line loading	Monitored	• Cut-in Rowville – Richmond 220 kV No. 1 and No. 4 circuits at Malvern Terminal Station to form the Rowville – Malvern – Richmond No. 3 and No. 4 circuits.	Increased demand or additional loads connected to Malvern Terminal Station.	Not identified as it is a localised issue	Any line cut-in is unlikely to be a contestable project
Rowville – Springvale – Heatherton 220 kV line loading*	Monitored	• Connect a third Rowville –Springvale circuit (underground cable). • Connect a Cranbourne – Heatherton 220 kV double circuit overhead line.	Increased demand or additional loads connected to Springvale and Heatherton Terminal Station.	Not identified as it is a localised issue	If needed, the third circuit is likely to be a contestable project
Rowville A1 500/220 kV transformer loading	Emerging	• Install a second 500/220 kV 1,000 MVA transformer at Cranbourne and cut in the existing Hazelwood – Rowville No.3 500kV line at Cranbourne. • Install a third 500/220 kV 1,000 MVA transformer at Rowville, plus any fault level mitigation works. • Establish a new 500kV switch yard at Templestowe cutting into the existing South Morang – Rowville No. 3 500kV line and a new 500/220 kV 1,000 MVA transformer at Templestowe terminal station, plus any fault level mitigation works. • Establish a new 500kV switch yard at Ringwood cutting into the existing South Morang – Rowville No. 3 500kV line and a new 500/220 kV 1,000 MVA transformer at Ringwood terminal station, plus any fault level mitigation works.	Increased demand in Eastern Metropolitan Melbourne. Reduced supply in the 220kV metro network and increased supply from the 500kV network.	Not identified as a material limitation in the scenarios modelled.	Any line cut-in is unlikely to be a contestable project. The new transformer is likely to be a contestable project.
South Morang H1 330/220 kV transformer loading	Monitored	• Replace the existing transformer with a higher rated unit in conjunction with AusNet Services asset replacement program.	Increased demand in Metropolitan Melbourne and/or increased import from New South Wales.	Not identified as a material limitation in the scenarios modelled.	This is unlikely to be a contestable project
Cranbourne A1 500/220 kV transformer loading	Monitored	• Install a new 500/220 kV 1,000 MVA transformer at Cranbourne Terminal Station and cut in the existing Hazelwood – Rowville No.3 500kV line at Cranbourne.	Increased demand around the Eastern Melbourne Metropolitan area. Reduced supply in the 220kV metro network and increased supply from the 500kV network.	Not identified as a material limitation in the scenarios modelled.	Any line cut-in is unlikely to be a contestable project. The new transformer is likely to be a contestable project
South Morang – Thomastown No. 1 and No. 2 220 kV line loading	Monitored	• Increase the transfer capability by installing wind monitoring facilities on the South Morang to Thomastown line. • Install an automatic load shedding control scheme to enable the use of five-minute line rating.	Increased demand around the Melbourne Metropolitan area and/or increased export to New South Wales.	Not identified as it is a localised issue.	Any new transformer is likely to be a contestable project.

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
		• Install a third 500/220 kV 1,000 MVA transformer at Rowville, plus any fault level mitigation works.	Generation planting and retirements as per the 2022 ISP Step Change scenario.		
Moorabool – Geelong 220 kV line loading	Emerging	• Replacement of station limiting plant at Geelong Terminal Station to allow operation at the line conductor ratings. • Increase the transfer capability by installing wind monitoring facilities on the Moorabool – Geelong Lines. • Operational arrangements to reduce the post-contingent flow on the remaining Moorabool – Gelong line for loss of the parallel line. • Connect a new double circuit Moorabool – Geelong 220kV line with a rating of approximately 800 MVA at 35ºC, plus any fault level mitigation works.	Large-scale new generation connected to western Victoria area, and congestion within western Victoria relieved to allow the new generation to be sent out of western Victoria. Generation planting and retirements as per the 2022 ISP Step Change scenario. Increased maximum demand in Metro Melbourne.	Not identified as a material limitation in the scenarios modelled.	If needed,this is likely to be a contestable project.
Geelong - Keilor 220 kV line loading	Priority	• Replace the existing Geelong – Keilor 1 and 3 220 kV lines with a new double circuit line, each circuit rated at 800 MVA at 35ºC. • Replace the existing Keilor 500/220 kV transformers with a lower impedance unit in conjunction with AusNet Services asset replacement program.	Large-scale new generation connected to western Victoria area, and congestion within western Victoria relieved to allow the new generation to be sent out of western Victoria. Generation planting and retirements as per the 2022 ISP Step Change scenario. Increased maximum demand in Metro Melbourne.	Not identified as a material limitation in the scenarios modelled.	The new lines are likely to be a contestable project.
Keilor – Deer Park – Geelong 220 kV line loading	Priority	• Replace the existing Geelong – Deer Park and Deer Park – Keilor 220 kV lines with a new double circuit line rated at 800 MVA at 35ºC. • Cut in the existing two Geelong –Keilor No. 1 or No. 3 220 kV circuits to form three parallel Geelong – Deer Park and Deer Park – Keilor circuits.	Increased demand at Deer Park.	Not identified as a material limitation in the scenarios modelled.	These are unlikely to be contestable projects.
Keilor – Thomastown No. 1 220 kV line loading	Monitored	• Increase the transfer capability by installing wind monitoring facilities on the Keilor to Thomastown line. • Install an automatic load shedding control scheme to enable the use of five-minute line rating • Install a third 500/220 kV 1,000 MVA transformer at Rowville, plus any fault level mitigation works.	Reduced supply from Eastern Victoria and increased supply from Western Victoria.	Not identified as it is a localised issue.	The new transformer is likely to be a contestable project.

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2022 NSCAS	Contestable project status
Sydenham – Keilor 500 kV line loading	Monitored	• Line limiting plant upgrades at Sydenham and Keilor terminal stations • Install a new single circuit Sydenham – Keilor 500 kV line with a rating of approximately 2,900 MVA at 35ºC. • Uprate line rating of the existing 500 kV SYTS–KTS	Increased generation in west and southwest Victoria supplying Keilor Terminal Station.	Not identified as a material limitation in the scenarios modelled.	The new line is likely to be a contestable project.

* These monitored limitations assume five-minute ratings are already applied. An automatic load shedding control scheme to enable five-minute line ratings is currently available to manage this limitation.

A4.7 Western Victoria REZ

Table 34 Limitations in Western Victoria REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana 220 kV line	Monitored	• Install automatic generation runback control schemes. • Install a new double circuit Bulgana to Murra Warra 220kV line via a new terminal station at Horsham.	Increased generation in Western Victoria and Murray River REZ.	Not identified.	These are unlikely to be contestable projects.
Inadequate reactive power support in Regional Victoria	Monitored	• Staged installation of additional reactive power support in Regional Victoria.	Increased maximum demand and/or reactive power consumption in regional Victoria.	2022 ISP/NSCAS did not identify this limitation as it is a localised issue.	Additional reactive support is unlikely to be a contestable project.

A4.8 Victoria system-wide

Table 35 Limitations in the Victorian system

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Insufficient demand to dispatch system strength services from synchronous generation	Monitored	• Install synchronous condensers at strategic locations of the network • Install grid forming BESS	Decreasing minimum demand	2022 ISP/NSCAS did not identify this limitation	This is likely to be a contestable project.

Abbreviations

Abbreviation	Term in full
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APD	Alcoa Portland
AVP	AEMO Victorian Planning
BESS	Battery energy storage system/s
CBTS	Cranbourne Terminal Station
COAG	Council of Australian Governments
DER	Distributed energy resources
DNSP	Distribution Network Service Provider
DSN	Declared Shared Network
EFCS	Emergency Frequency Control Scheme
EPS	Eildon Power Station
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
GFT	Generation fast tripping
GFT2	Generator Fast Trip Scheme 2
GPG	Gas-powered generation
GW	Gigawatts
HSM	High-speed monitors
HVDC	High-voltage direct current
HWPS	Hazelwood Power Station
IASR	Inputs, Assumptions and Scenarios Report
IECS	Interconnector Emergency Control Scheme
IRM	Interim Reliability Measure
ISP	Integrated System Plan
JPB	Jurisdictional Planning Body
KTS	Keilor Terminal Station
kV	Kilovolts
LOR	Lack of Reserve
MLTS	Moorabool Terminal Station
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
NCIPAP	Network Capability Incentive Project Action Plan
NEL	National Electricity Law

NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NEVA	National Electricity Victoria Act
NMAS	Non-market ancillary services
NSCAS	Network Support and Control Ancillary Services
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PMU	Phasor Measurement Unit
POE	Probability of exceedance
PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic
RDP	Renewable Energy Zone Development Plan
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable energy zone
RIT-T	Regulatory Investment Test for Transmission
ROCOF	Rate of change of frequency
ROTS	Rowville Terminal Station
SCADA	Supervisory Control And Data Acquisition
SIPS	System Integrity Protection Scheme
SMTS	South Morang Terminal Station
SVC	Static Var compensator
TNSP	Transmission network service provider
TSDF	Terminal station demand forecast
UFLS	Under-frequency load shedding
USE	Unserved energy
VAPR	Victorian Annual Planning Report
VNI	Victoria – New South Wales Interconnector
VPP	Virtual power plant
VRE	Variable renewable energy
VRET	Victorian Renewable Energy Target
VSAT	Voltage stability assessment tool
YPS	Yallourn Power Station