AEMO
AUSTRALIAN ENERGY MARKET OPERATOR
Victorian Planning

Victorian Annual Planning Report

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Published by AEMO Victorian Planning under its declared network functions in 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 publishes the Victorian Annual Planning Report (VAPR) under its declared network functions in Victoria, and in accordance with clause 5.12 of the National Electricity Rules. This publication is generally based on information available to AEMO as at June 2022, although AEMO has incorporated more recent information where practical.

Disclaimer

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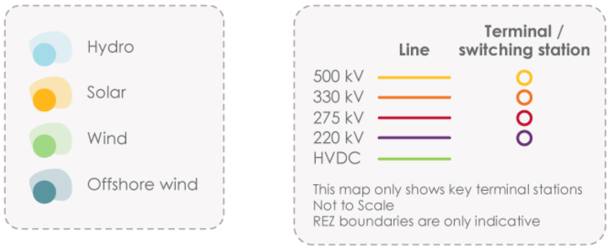
Acknowledgement

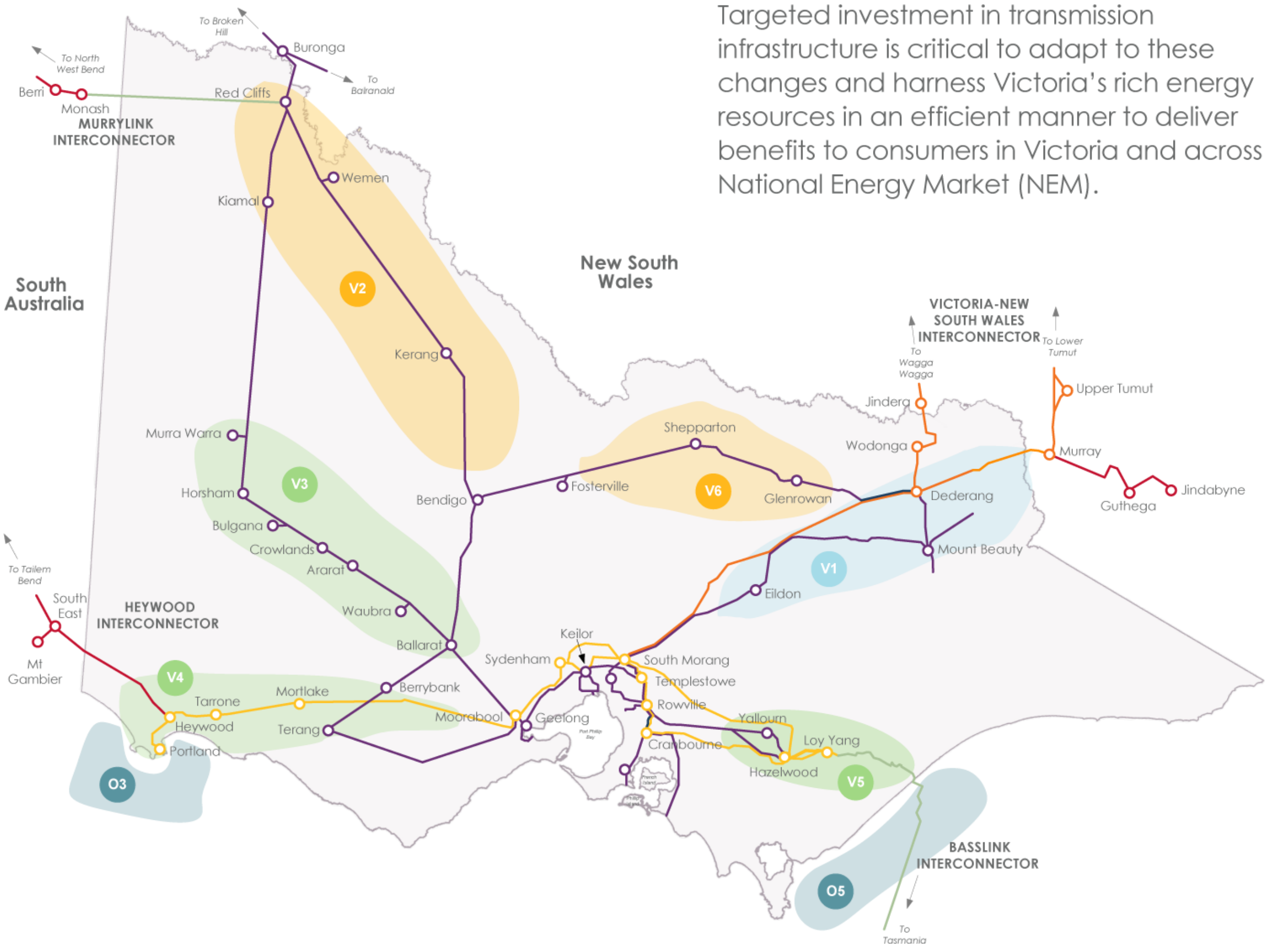
AEMO acknowledges the support, co-operation and contribution of Victorian Network Service Providers in providing data and information used in this publication.

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.



Australia's electricity industry is rapidly transforming, driven by strong investment in large-scale renewable generation and the rapid rise of distributed photovoltaic (PV) installations on homes and businesses across the state. New technologies and changing human behaviour are also having a significant influence on this transformation.

Targeted investment in transmission infrastructure is critical to adapt to these changes and harness Victoria's rich energy resources in an efficient manner to deliver benefits to consumers in Victoria and across the National Energy Market (NEM).



Renewable Energy Zones in Victoria

- V1 Ovens Murray REZ
- V2 Murray River REZ
- V3 Western Vic REZ
- V4 South West Vic REZ
- V5 Gippsland
- V6 Central North
- O3 Portland Offshore
- O5 Gippsland Offshore

Annual peak operational demand in 2021-22

8,599 MW

On 27 January 2022

Annual minimum operational demand in 2021-22

2,333 MW

on 25 November 2021

Installed generation capacity in Victoria

18.6 GW

At 31 July 2022

Coal	4.84
Wind	4.03
Distributed PV	3.50
Gas	2.47
Hydro	2.25
Solar	1.01
Battery Storage	0.38
Biomass	0.06
Total	18.60

Executive summary

Under its declared network functions set out in the National Electricity Law (NEL), the Australian Energy Market Operator (AEMO) is responsible for planning and directing augmentation on the Victorian electricity transmission Declared Shared Network (DSN). Throughout this document, AVP (AEMO Victorian Planning) refers to AEMO in its Victorian Planning role. AVP works closely with stakeholders, including other network service providers (NSPs), industry stakeholders, consumer representatives, the Victorian Government and other interested parties, to develop the power system in the most efficient way for the benefit of Victorian consumers.

AVP publishes the *Victorian Annual Planning Report* (VAPR) each year to inform stakeholders about DSN performance, planning, challenges and opportunities in the next 10 years. The 2022 VAPR builds on the national plan developed through AEMO's *Integrated System Plan* (ISP) and provides local insights relating to:

- **Network performance** over the past year.
- **Adequacy of the network to meet reliability and security needs** over the coming 10 years and adapt to the rapid transformation to a renewable energy power system.
- **Network limitations** and potential solutions to alleviate them, including the impact of Victorian Government's recently announced Renewable Energy Zone (REZ) Development Plan (RDP) Stage 1 projects.
- **Transmission development for Victoria** to deliver lower-cost outcomes for consumers under the current regulatory framework.

The Victorian transmission network remained largely secure[1] in 2021-22, despite record low minimum operational demand

In 2021-22, Victoria recorded its **all-time lowest minimum operational demand of 2,333 megawatts (MW) on 28 November 2021**. This was 196 MW lower than the previous record, set in 2020-21. This was the fourth consecutive year in which the annual minimum operational demand record has occurred during the daytime, driven by continued uptake in distributed solar photovoltaics (PV). This trend is forecast to continue, and the record has already been broken in this current financial year, with a minimum operational demand of 2,285 MW observed on 2 October 2022.

The installation of the two reactors at Keilor Terminal Station has eliminated the need for operational intervention to manage high voltages despite the increasing number of low demand days. Another two reactors installed at Moorabool Terminal Station in 2022 will provide further headroom in managing network voltages as demand is forecast to reduce further in future.

The **annual peak Victorian operational demand in 2021-22 was 8,599 MW on 27 January 2022**, compared to the peak of 8,411 MW in 2020-21. Summer-driven maximum demand has remained relatively low in the past two years, driven by milder weather conditions which led to lower cooling requirements in Melbourne. The highest historical summer maximum operational demand in Victoria was 10,576 MW in 2008-09.

[1] AEMO identified that on 15 June 2022 there were two periods of less than 30 minutes where northerly flows across the Victoria – New South Wales Interconnector (VNI) exceeded secure levels.

In 2021-22, there was no directed load shedding and no emergency reserves were activated through Reliability and Emergency Reserve Trader (RERT).

There were two notable power system incidents in 2021-22:

- A 220 kilovolts (kV) line trip due to a lightning strike on 1 March 2022 resulted in collective loss of approximately 110 MW of generation in the West Murray area.
- AEMO suspended the spot market in all National Electricity Market (NEM) regions between 15 and 24 June 2022, when the number and scale of interventions needed to manage actual and forecast reserve shortfalls made it impossible to continue operating the spot market in accordance with the rules[2]. Prior to the market suspension on 15 June 2022, there were two periods of less than 30 minutes where northerly flows across the Victoria – New South Wales Interconnector (VNI) exceeded secure levels.

Several terminal stations that have historically been net loads are increasingly becoming net generation sources due to increases in distribution-connected generation. In 2021-22, 15 locations experienced reverse flows, up from nine locations in 2020-21.

Unprecedented changes are anticipated in how Victoria generates and consumes electricity in future

The Victorian energy landscape continues to transform, driven by continued development of large-scale renewable generation in regional areas, ongoing strong uptake by consumers of distributed energy resources (DER), and the withdrawal of synchronous generation.

The total installed generation capacity in Victoria has increased to 18.6 gigawatts (GW) as of 31 July 2022:

- 7.7 GW of large-scale renewable generation (wind, solar, storage and hydro), which now exceeds the total installed capacity of conventional generation (coal and gas) in Victoria.
- 7.4 GW of large-scale conventional generation (coal and gas).
- Approximately 3.5 GW[3] of DER, including 3.5 GW of distributed PV systems and 42 MW of distributed storage.

Since the 2021 VAPR, 2.4 GW of new large-scale solar and wind projects have connected in Victoria. Another 267 MW of wind projects are committed to connect, and approximately 37.5 GW of additional wind (onshore and offshore), solar and battery storage projects are proposed.

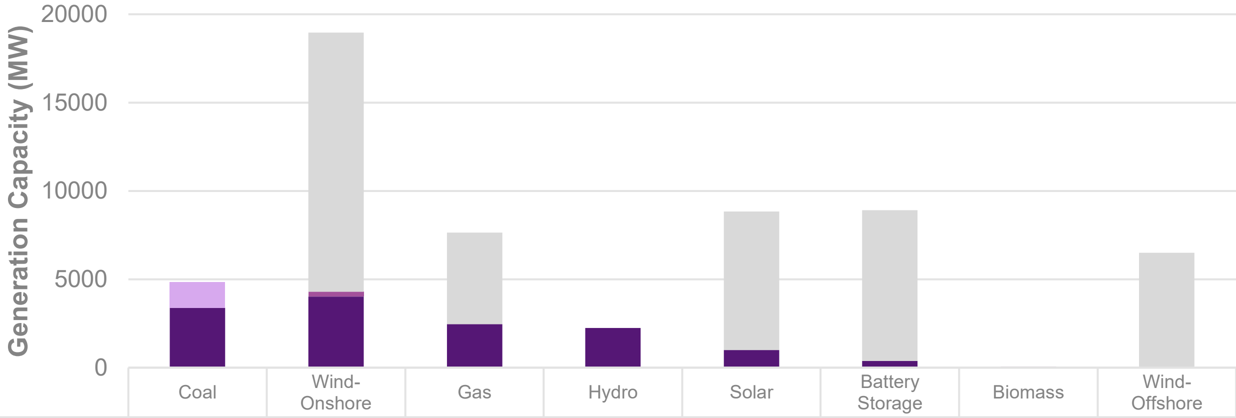
Figure 1 shows large-scale generation and storage capacity that is currently operating, committed, or proposed in Victoria[4].

[2] For more detail on the events and conditions leading to the suspension, see AEMO's market event and reviewable operating incident report at https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf

[3] See AEMO DER Register (https://aemo.com.au/energy-systems/electricity/der-register) and https://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations. Data is taken up to 30 June 2022.

[4] From AEMO, Generation Information webpage, Victoria update August 2022, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Definitions and criteria for committed projects are under the "Background information" tab in each Generation Information update file.

Figure 1 Currently existing, committed, and proposed large-scale generation and storage capacity in Victoria



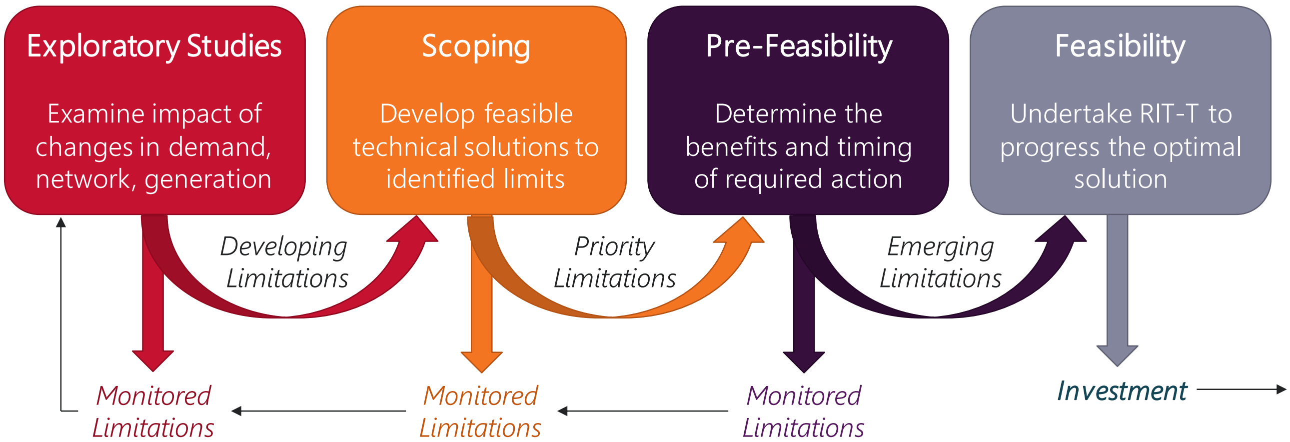
	Coal	Wind-Onshore	Gas	Hydro	Solar	Battery Storage	Biomass	Wind-Offshore
Proposed projects		14668	5174		7827	8536		6500
Committed projects		267						
Announced Retirement	1450							
Existing [less Retirement]	3385	4029	2467	2248	1005	375	58	

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.

Generation and storage changes are expected to introduce new network limitations and challenges

As part of the annual planning cycle, AVP identifies and categorises network limitations based on criticality and likelihood that a network or non-network solution exists that would meet the objectives of a Regulatory Investment Test for Transmission (RIT-T). The categorisation, as shown in Figure 2 below, also influences the type of studies that AVP undertakes in response to the identified limitation.

Figure 2 Identification of network limitations – the planning cycle



Three new emerging limitations were identified in the full review of the Victorian power system this year. The first of these limitations is driven by increasing need for system strength support in Metropolitan Melbourne and the others are driven by increasing maximum and reducing minimum operational demand forecasts in the 2022 *Electricity Statement of Opportunities* (ESOO). AVP will commence feasibility assessment, including RIT-Ts if necessary, within 12 months to identify the preferred solutions and timings to relieve the following emerging limitations:

- Minimum fault level requirements at Thomastown, Moorabool and Hazelwood fault level nodes.
- High voltages in Metropolitan Melbourne and South West Victoria.
- Metropolitan Melbourne area voltage stability.

No new priority limitations have been identified in this VAPR. Of the five priority limitations identified in the 2021 VAPR, four have now been reclassified as monitored limitations following recent announcements of the RDP Stage 1 projects, and one (High voltages caused by low and negative demand) is now a new emerging limitation.

Seven developing limitations are currently under investigation. Of these, five were identified in past VAPRs (predominantly due to uptake of generator connections in regional areas, increasing maximum demand and decreasing minimum demand, and the announced retirement of Yallourn Power Station [YPS] in 2028) and two are new developing limitations (driven by increased load in Metropolitan Melbourne, specifically at Deer Park Terminal Station).

This VAPR provides an update on two key challenges faced by the Victorian DSN over the coming 10 years:

- Rapidly declining minimum demand.
- Announced and anticipated retirements of coal generation.

Rapidly declining minimum demand

The 2022 ESOO for the NEM projects minimum demand (90% probability of exceedance [POE] forecasts) in Victoria going negative (meaning DER is forecast to generate more than underlying demand at these times) in the next decade – from 2030-31 in the ESOO Central (*Step Change*) scenario, 2027-28 in the *Progressive Change* scenario, and 2026-27 in the *Slow Change* scenario[5].

Although the 2022 ESOO Central scenario demand forecast is higher than the 2021 ESOO Central forecast, voltage control and system strength management during low demand periods in Victoria, under both system normal and prior outage conditions, are still expected to present challenges.

AVP has:

- Revised the immediate, short-term, and long-term limitations that would need to be addressed to manage voltages during low demand periods.
- Identified a mix of operational measures and reactive power capability from new generation/battery connections and new grid-connected reactive plant as potential solutions to the limitations.

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

Announced and anticipated retirements of coal generation

The 2022 ISP *Step Change* outlook forecasts retirement of synchronous generation earlier than the announced dates. These earlier retirements, and the subsequent uptake of supply resources elsewhere in the DSN, would substantially impact the flow patterns of the network, resulting in:

- Alleviation of typical limitations on the retired synchronous generation.
- Exacerbation of limitations elsewhere, due to the increased uptake of generation where transmission capacity would need to be upgraded, and the loss of reactive support from retired synchronous units, coupled with increasing maximum demand and decreasing minimum demand exacerbating voltage and stability limitations.

The coal generation retirement impact on DSN performance is sensitive to how the Latrobe Valley network would be configured going forward, which in turn will affect asset utilisation and the network need for some assets in the Latrobe Valley.

The 2022 ESOO also forecast that the reliability standard in Victoria would not be met from 2028-29 due to generation retirements, even if currently anticipated and actionable projects were developed, highlighting an urgent need for more dispatchable generation and storage to become committed. AVP is investigating further opportunities to mitigate against a potential reliability gap, including options to unlock Victorian generation by investing in network and non-network solutions that relieve identified limitations.

Transmission will be key to unlocking carbon neutral, efficient energy in future

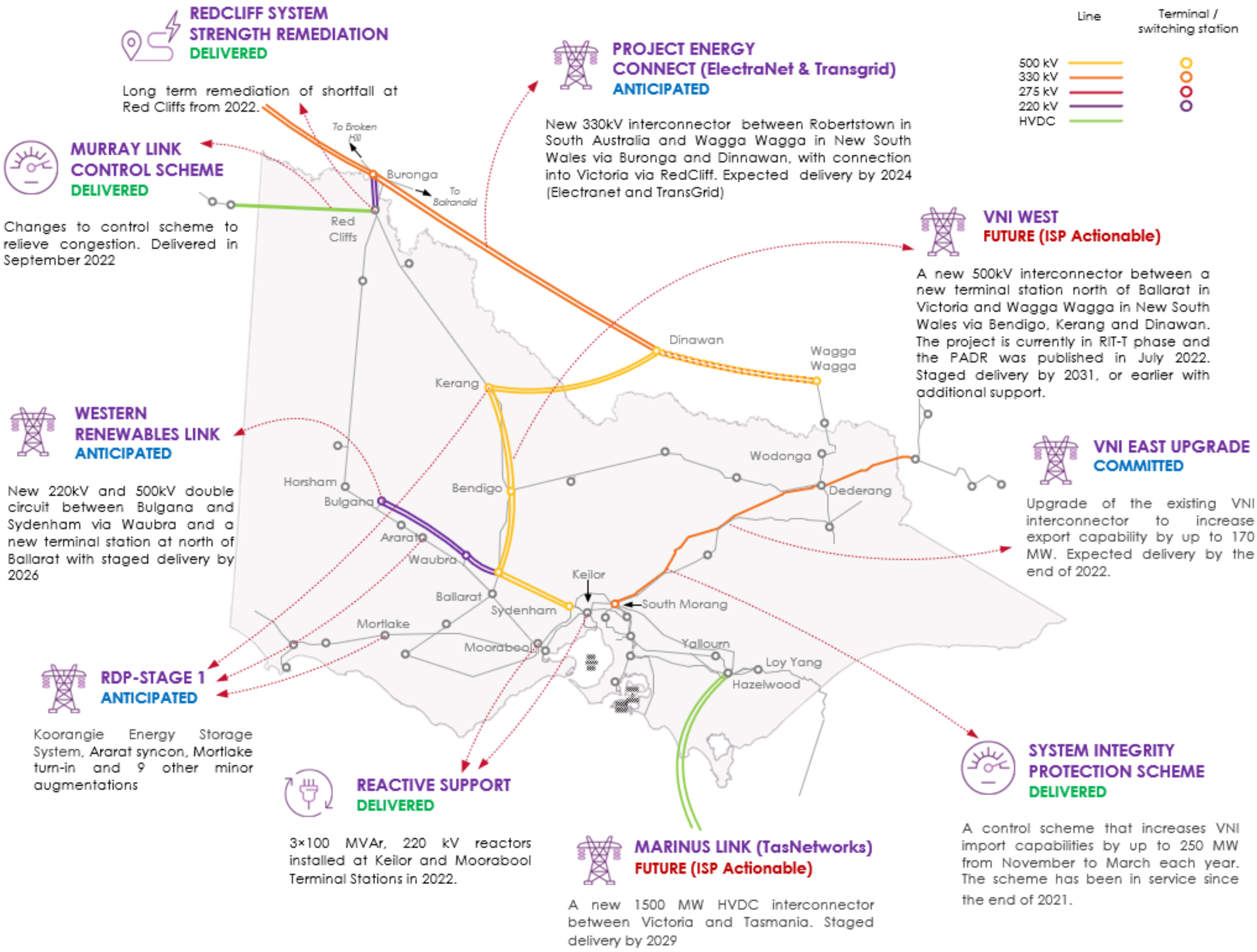
Targeted and timely investment in transmission infrastructure is required to provide consumers with the most efficient energy outcomes that leverage the geographic diversity of renewable resources, while adapting to the newly emerging technical characteristics of the power system.

To meet the forecast future needs of the system, AVP is progressing a suite of projects across the state through its *Transmission Development Plan for Victoria*, shown in Figure 3. These investments act to reduce overall costs to consumers by unlocking lower-cost generation supplies, enhancing competition, and improving the efficiency of resource sharing between neighbouring regions.

In addition to the projects being delivered under the regulatory investment framework, the plan also includes the Victorian Government's recently announced RDP investments, which includes services to strengthen the system in the Murray River and Western Victoria REZs, turn-in of the Haunted Gully to Tarrone 500 kV line to Mortlake Power Station, and nine minor augmentations designed to increase network capacity and harness existing and future renewable generation across the Murray River, South West and Central North REZs.

The individual projects in the *Transmission Development Plan for Victoria*, including the RDP investments, are explained in more detail in this report. Together these projects target key thermal, stability, voltage control, system strength, and REZ expansion limits across the region and interconnector transfer limits with neighbouring regions.

Figure 3 AVP's *Transmission Development Plan for Victoria*



Note: map not to scale. Routes of transmission lines and location of new terminal stations are illustrative only, and not all terminal stations are shown or labelled.

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1 Introduction

This chapter introduces the purpose and content of the 2022 *Victorian Annual Planning Report* (VAPR), including the key regulatory, policy, operational, network, and connections context in which the report has been prepared.

Purpose, scope, and structure of the 2022 VAPR

AEMO publishes the VAPR in its role as the Victorian transmission planner under the National Electricity Law (NEL), in accordance with clause 5.12 of the National Electricity Rules (NER).

The 2022 VAPR assesses the adequacy of the existing Victorian Declared Shared Network (DSN) to meet reliability and security needs in the past year, and for planning and directing augmentation on the forecast DSN over the next 10 years. The VAPR adapts to the changing nature of demand and considers changes in the geography and characteristics of supply 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 network security, reliability of supply, forecast demand, network capability, system performance, and emerging network development needs, with a particular focus on those most likely to deliver net economic benefits and lower costs for consumers.

In the 2022 VAPR:

- **Chapter 2** reviews the performance of the DSN throughout 2021-22, including new operational challenges, notable power system incidents, performance of the network under a range of operating conditions.
- **Chapter 3** provides an update on the network investment activities and investigations that have progressed since 2021 to facilitate the integration of new renewable generation while supporting Victorian power system security and reliability.
- **Chapter 4** explores potential new emerging or changed limitations that may reduce system performance, impact efficient asset utilisation, or result in additional network constraints. Identified limitations may warrant heightened monitoring, further options analysis, or trigger the need for investment.
- **Chapter 5** presents updated information on AusNet Services' Asset Renewal Plan, outlining expected network asset retirements, deratings, and renewals within the VAPR's 10-year timeframe, including AEMO's assessment of the future network needs associated with these assets.

AEMO also welcomes feedback from stakeholders on the *Victorian Annual Planning Report* via https://aemo.com.au/contact-us.

Unless otherwise stated, all times are Australian Eastern Standard Time (AEST), and all dollar amounts are in real 2022 dollars.

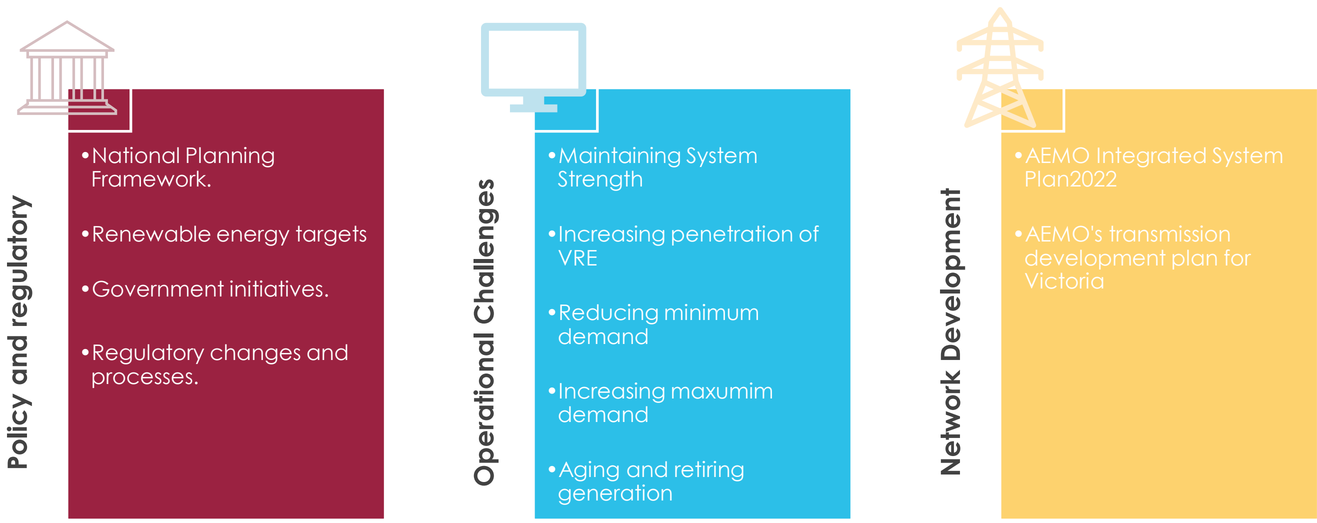
1.1 Context of the 2022 VAPR

The energy landscape in Victoria continues to change, driven by strong investment in large-scale and distributed renewable generation in traditional load centres and remote locations. New large-scale investment in the west of the state is creating additional supply centres, while increasing penetration of non-synchronous generation continues to impact system stability and the operational complexity of the power system. Consumer-led investment in distributed energy resources (DER) has altered the shape of the daily demand curve and is creating new challenges through new record levels of minimum demand, while the growth of DER and large-scale renewable generation is decreasing levels of reactive power capability, inertia, and system strength.

The context for network development is changing rapidly, both nationally and regionally, with multiple moving pieces across regulatory, policy, operational, network and connection areas.

Figure 4 summarises the key context areas that are each explored in more depth in this chapter.

Figure 4 Key context areas for the 2022 VAPR



1.1.1 Policy and regulatory context

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

The national planning framework

The national transmission planning framework streamlines the regulatory framework by allowing outputs from the ISP to be incorporated into transmission network service provider (TNSP) investment decisions[6]. Under this approach:

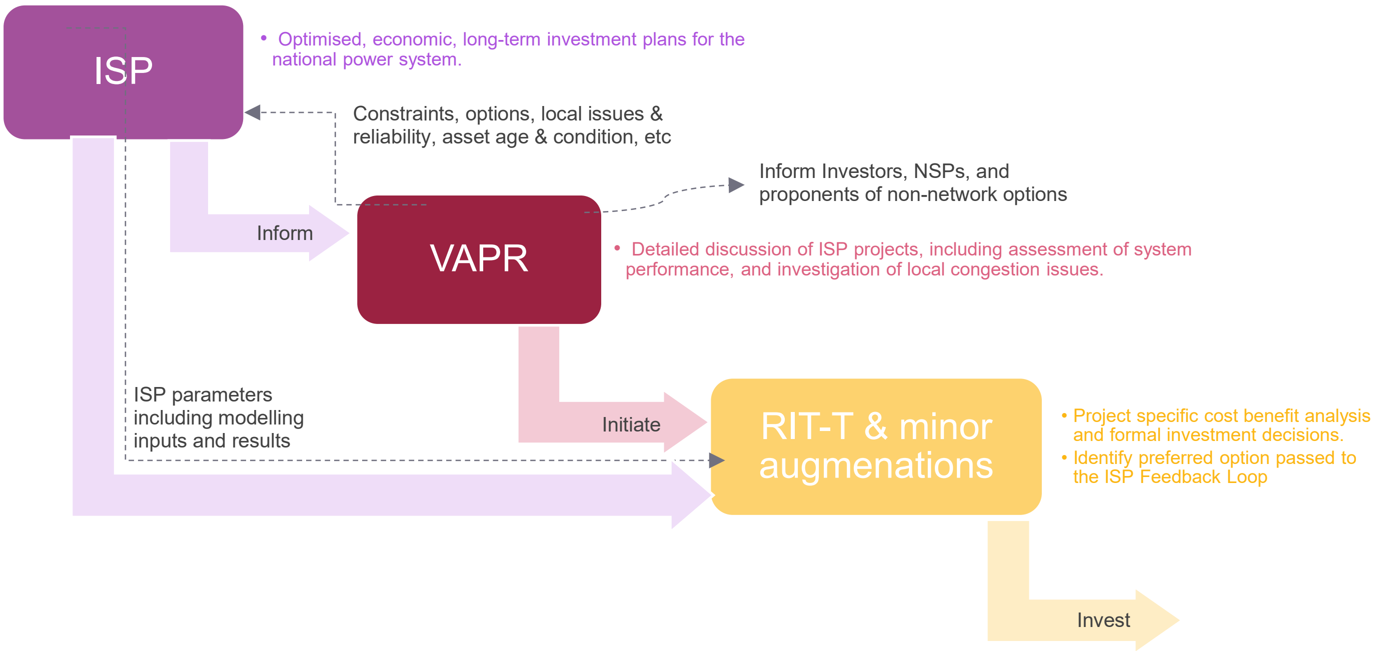
- Comprehensive system-wide modelling in the ISP identifies network needs and a set of options that efficiently meets those needs, as part of an optimised development path for the National Electricity Market (NEM).

[6] See http://www.coagenergycouncil.gov.au/publications/actionable-isp-final-rule-recommendation.

- The VAPR leverages these nationally optimised plans and overlays them with more granular information 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 then aims to validate project benefits, explore lower-cost variations, and ensure any subsequent investment decision is robust and transparent.

This relationship is presented in Figure 5.

Figure 5 Relationship between the ISP, VAPR, and RIT-T in the national planning framework



Legislated emission reduction policies

Through the **Victorian Renewable Energy Target Auction #2 (VRET2)**[7], six projects have been announced by the Victorian Government to bring online 623 megawatts (MW) of new renewable energy generation capacity and up to 365 MW/600 megawatt hours (MWh) of new battery storage energy storage.

The Victorian Government was also one of the first jurisdictions in the world to legislate net zero by 2050, through the ***Climate Act 2017***. Interim targets are to cut emissions 28-33% below 2005 levels by 2025 and 50% by 2030.

The Australian Government, under the ***Climate Change Bill 2022***, has legislated a 43% reduction in emissions by 2030 and net zero by 2050.

[7] See https://www.energy.vic.gov.au/renewable-energy/a-clean-energy-future/victorian-renewable-energy-target-auction-vret2.

Victorian Government initiatives

To help cut emissions, the Victorian Government has made several policy announcements and commitments that are impacting on the drivers for, and economics of, investment in the Victorian network. These include:

- **Renewable Energy Zone (REZ) Development Plan** – in August 2021, the Victorian Government directed AEMO Victorian Planning (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, identified in the RDP Directions Paper[8]. In January 2022, the Victorian Government also directed AVP to progress procurement activities for turn-in of the Haunted Gully to Tarrone 500 kilovolts (kV) line at Mortlake.
  - As detailed in Section 3.4.3, AVP has now completed procurement activities and entered services contracts for two of the three contestable services to strengthen the system, all nine non-contestable minor augmentations, and the turn-in of the Haunted Gully to Tarrone 500 kV line at Mortlake. Procurement activities for the remaining contestable services to strengthen the system in the South Western Victoria REZ are ongoing.
- The Victorian Government published the **Offshore Wind Policy Directions Paper**[9] in March 2022, outlining a plan to procure an initial wind tranche of 2 gigawatts (GW) by 2032 with targets of 4 GW by 2035 and 9 GW by 2040. The **Offshore Wind Implementation Statement 1** published in October 2022[10] provided more details on how the government proposes to establish the offshore wind industry in Victoria, including its intent to lead the development of transmission infrastructure to coordinate offshore wind connections, working with AVP.
- **In the energy innovation fund**[11], three offshore wind projects secured $37.9 million funding under Round 1 to support feasibility and pre-construction activities. Assessment and evaluation of Round 2 (technology-neutral) applications has commenced, and projects are expected to be announced in 2022.
- The **Solar Homes Program** has been expanded to include the Virtual Power Plant (VPP) pilot program, where 2,000 households will receive a rebate of $4,174 when they install a battery. The initiatives under the Solar Homes program effectively reduce, and change the shape of, operational demand in Victoria.
- **Victoria's Gas Substitution Roadmap[12],** released by the Victorian Government, aims to empower households and businesses in Victoria to embrace sustainable alternatives to fossil gas. The 2022 ESOO projects that this will lead to greater electrification, therefore it contributed to the projected growth in electricity demand.
- **Victoria's energy storage targets[13]** were recently announced and 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 energy storage targets will include both short- and long-duration energy storage systems, allowing energy to be moved around during the day and also to be supplied through longer duration imbalances.

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

[9] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0016/561400/Offshore-Wind-Policy-Directions-Paper.pdf.

[10] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0030/603399/The-Victorian-Offshore-Wind-Implementation-Statement-1.pdf.

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

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

[13] See https://www.energy.vic.gov.au/renewable-energy/a-clean-energy-future/victorian-renewable-energy-and-storage-targets.

Regulatory changes and processes

The Australian Energy Market Commission (AEMC) has made the following rule changes since the 2021 VAPR:

- **Efficient management of system strength on the power system**[14] – the AEMC made a final rule determination designed to proactively deliver forecast system strength needs. It has three main elements: supply side (to commence 1 December 2022), coordination, and demand side reforms (both to commence 15 March 2023). See Section 4.5.2 for more information on how this rule affects AVP's planning activities for the Victorian DSN.
- **Enhancing operational resilience in relation to indistinct events**[15] – on 3 March 2022, the AEMC made a final rule to expand the contingency event framework to allow AEMO to manage the risk of indistinct events.
- **Material change in network infrastructure project costs**[16] **–** on 7 July 2022, the AEMC published the draft determination and a 'more preferable' draft rule on the Material change in network infrastructure project costs rule change.

The Victorian Government also commenced consultation on proposed changes to the Victorian transmission investment framework (VTIF)[17] to facilitate efficient development of the Victorian REZs.

1.1.2 Operational context

Victoria continues to attract investment in both large-scale and distributed variable renewable energy (VRE) resources, which is drastically shifting the demand and supply pattern across the state.

Traditional load centres are fast developing into supply hubs, while DER are shifting the consumer load profile. With forecast increases in distributed photovoltaics (PV), storage, electric heating and electric vehicles, this trend is expected to gather pace and present significant development needs in the planning timeframe of the next 10 years.

Maintaining system strength in Victoria

- AEMO's 2021 *System Security Reports*[18] declared system strength gaps around Metropolitan Melbourne and the Latrobe Valley due to early retirement of plant in the *Step Change* scenario considered most likely by stakeholders.
- System strength issues are expected to exacerbate under system normal, and may require direction of units due to continuingly reducing minimum demand and expected retirements of coal generation. Planning network outages which will reduce system strength will become increasingly difficult with a reduced number of baseload units available.
- Managing power system security during high renewable generation periods, planned and unplanned outages, especially in north-west Victoria, is causing congestion and raising new power system stability challenges.

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

[15] See https://www.aemc.gov.au/rule-changes/enhancing-operational-resilience-relation-indistinct-events#:~:text=The%20COAG%20Energy%20Council%20submitted,%27%20or%20%27condition%20dependent%27.

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

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

[18] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/update-to-2021-system-security-reports.pdf?la=en.

- Monitored limitations in the West Murray region under prior outage conditions and during forced outages continue to present stability risks and challenges in planning maintenance, and require a minimum number of synchronous generators to be online in Victoria and South Australia.

Increasing penetration of variable renewable energy (VRE)

- Anticipated large-scale new generation and retirement of conventional generation units could make network outage management more challenging due to reduced maximum supportable demand and system strength shortfall, resulting in an increase in the threshold demand value (below which certain planned outages would be prohibitive).
- Increasing distributed PV penetration will negatively impact the load blocks available for shedding and system restart. Voltage and frequency control will also become increasingly difficult with increasing magnitude and duration of reverse power flows.
- With increasing penetration of distributed PV, the size of the largest contingency in Victoria may potentially start to include mass tripping of DER[19] (in addition to a unit trip) due to legacy inverter disturbance ride-through characteristics.
- The offshore wind targets announced by the Victorian Government will significantly shift the energy flow paths within the state and on existing and future interconnectors

Reducing minimum and increasing maximum demand and supply forecast

Historically, voltage control during low demand periods required frequent operator interventions in both the 500 kV and 220 kV network.

This issue has improved since additional reactive capability at Keilor and Moorabool reactors, and reactive support from recently commissioned large wind farms and the Victorian Big Battery (VBB), has become available. As a result, AEMO has not extended its Non-Market Ancillary Services (NMAS) contract to help manage these voltage control challenges. However, with reducing demand forecast in Victoria, voltage management interventions may be required again in the future.

The 2022 ESOO[20] forecast a reliability gap in Victoria:

- In the ESOO Central[21] scenario, expected unserved energy (USE) is greater than the Interim Reliability Measure (IRM) in 2024-25 and the reliability standard from 2028-29, following the expected retirement of Yallourn Power Station. This reliability assessment excludes all investments that have not yet completed all necessary approvals and met AEMO's commitment criteria, such as the Western Renewables Link.
- Under its *Anticipated and actionable* sensitivity, which assumed the development of anticipated (not yet committed) generation and storage projects, and transmission projects classed as anticipated or actionable in the ISP, the ESOO forecast Victoria's reliability outlook could improve considerably. In this sensitivity,

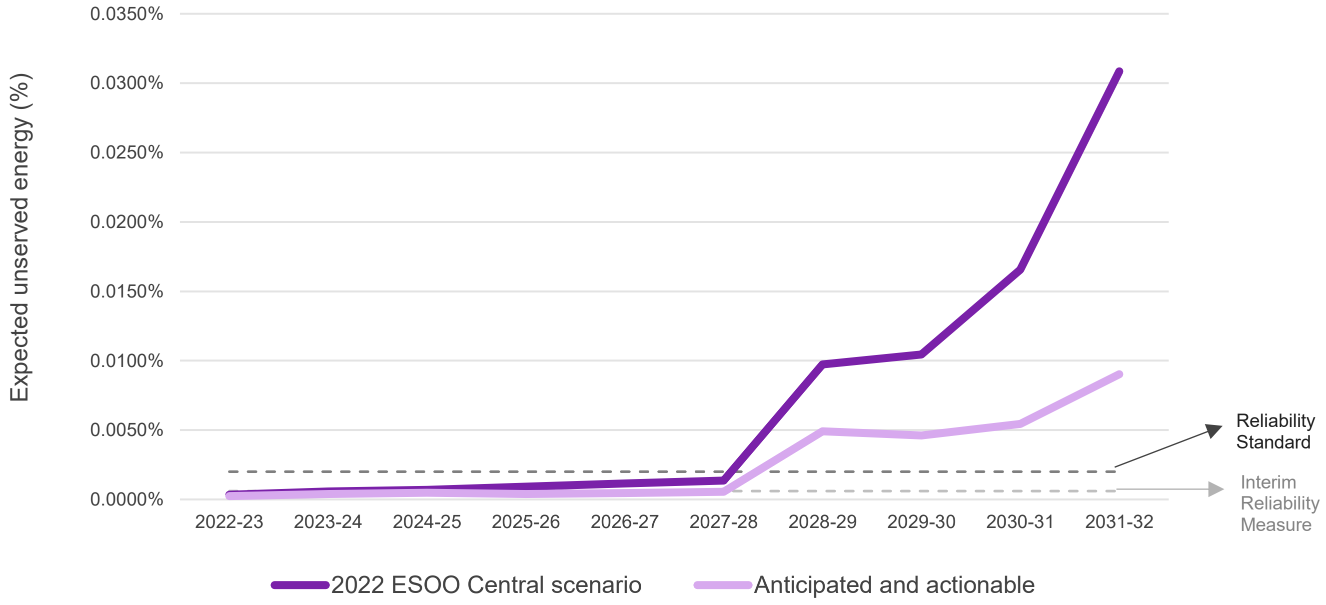
[19] See AEMO, *Behaviour of distributed resources during power system disturbances*, May 2021, at https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[20] 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.

[21] The 2022 ESOO Central scenario represents the *Step Change* scenario described in the 2022 ISP and the 2021 *Inputs, Assumptions and Scenarios Report* (IASR): see https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

however, USE is still forecast to exceed the reliability standard from 2028-29 due to generation retirements, highlighting the need for more generation, storage and transmission to be developed.

Figure 6 Victoria expected USE, scenarios and sensitivities, 2022-23 to 2031-32 (%)



Maximum operational demand in Victoria is forecast in the 2022 ESOO to be generally higher than the 2021 ESOO and 2022 ISP forecasts, due to higher forecast underlying demand, including growth from large industrial load.

Victoria is expected to become winter-peaking by around 2031-32 in the 50% probability of exceedance (POE) central forecast. This is driven by projected electrification of traditional gas loads, particularly heating loads in Victoria, increasing forecast consumption and maximum demands in winter.

Minimum operational demand in Victoria is forecast to decline rapidly in all scenarios, due to the projected uptake of distributed PV, although the minimum demand forecast in 2022 ESOO Central forecast is higher than the ISP 2022 *Step Change* forecast. In the absence of market-based solutions that might increase operational demand (including coordinated storage and EV charging, scheduled loads such as pumping load, and demand response) the minimum demand is forecast to go negative in 2030-31 in the ESOO Central scenario, 2027-28 in the *Progressive Change* scenario, and 2026-27 in the *Slow Change* scenario.

While distributed PV uptake is greatest in the Central scenario, underlying minimum demand is also highest in that scenario due to greater electrification of transport and heating, resulting in this Central scenario having the highest minimum operational demand.

Aging and retiring generation in the NEM

The coal generation fleet across Victoria (and the NEM) is aging, therefore its reliability and availability is progressively decreasing:

- Energy Australia has announced that it will retire Yallourn Power Station in mid-2028 and build a four-hour utility-scale battery of 350 MW by 2026 in the Latrobe Valley.

- Origin Energy has announced plans to retire Eraring Power Station in New South Wales in 2025, seven years earlier than previously scheduled, and build a two-hour 700 MW battery on the site.
- AGL has updated the expected closure year for Bayswater (2030-33) and Loy Yang A power stations (2035) in New South Wales and Victoria respectively.

1.1.3 Network development

AEMO's 2022 *Integrated System Plan*

In June 2022, AEMO published the 2022 ISP, which acknowledges that the momentum toward decarbonisation has accelerated and confirms (based on extensive stakeholder consultation) the *Step Change* scenario as a foundation for planning NEM investment.

The 2022 ISP, under its optimal development path, supports major infrastructure development in Victoria. Refer to Chapter 3 of this report for an update on these projects.

The key changes in 2022 ISP projects from the previous 2020 ISP are:

- VNI West decision rules have been removed and delivery date is July 2031 or earlier, compared to 2027-28 in the 2020 ISP. The change in delivery date reflects current lead times rather than delayed benefit realisation.
- South West Victoria REZ Expansion is identified as a future ISP project that is not yet actionable, but is expected to be required in the future based on 2022 ISP modelling. To improve the assessment of the project in future ISPs, preparatory activities have been triggered to design and investigate the costs and benefits of South West Victoria REZ Expansion. AVP is undertaking preparatory activities for the South West Victoria REZ expansion and will publish a report on the outcome of these activities by 30 June 2023.
- Project EnergyConnect status has changed from actionable to committed/anticipated.
- Marinus Link decision rules have been removed and the delivery date is July 2029 for Stage 1 and July 2031 for Stage 2, compared to 2028-29 in ISP 2020. This delayed delivery date reflects current lead times for delivery as soon as possible.

AEMO's *Transmission Development Plan for Victoria*

Since the 2021 VAPR, significant progress has been made across a range of network planning and investment activities, which have either been completed or materially progressed during this period.

The 2022 VAPR explores the progress and significance of these developments in Chapter 3, and discusses ongoing works to maintain and refurbish the existing transmission network in Chapter 5.

1.2 Supporting material

AEMO has published a suite of electronic resources to support the content in this report. Descriptions are provided in Table 1.

Unless otherwise indicated, all files are published alongside the VAPR report on the AEMO website[22].

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

Table 1 2022 VAPR supporting resources

Resource	Description
Historical DSN rating and loading workbook	Presents ratings and loadings for the 2021-22 maximum demand and high export periods presented in Chapter 2.
AusNet Services 2022 asset renewal plan	Outlines 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.
Demand forecasts	The transmission connection point planning report, prepared by the Victorian Distribution Network Service Providers (DNSPs), provides information on historical and forecast demand, including DNSPs' terminal station demand forecast (TSDF) and the causes of differences between these and AEMO's connection point forecasts for Victoria. At https://dapr.ausnetservices.com.au/ausnet_data/2021%20TCPR_21%20Dec.pdf.
Power System Frequency Risk Review (PSFRR)	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%20System%20Frequency%20Risk,National%20Electricity%20Market%20(NEM).
System Strength and Inertia reports	AEMO's system strength, inertia and NSCAS assessments, collectively known as the *System Security Reports* under the NER (5.20). At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.
VNI West Project Assessment Draft Report (PADR)	At https://aemo.com.au/en/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission.

2 Network performance

This chapter reviews the performance of the Victorian DSN throughout 2021-22, including new operational challenges, notable power system incidents, and the performance of the network under a range of operating conditions.

Key network performance observations

The Victorian DSN remained largely secure in 2021-22, despite record low minimum demand and unprecedented levels of inverter-based renewable generation. Notable network performance observations are:

- The annual peak Victorian operational demand in 2021-22 was 8,599 MW on 27 January 2022, compared to 8,411 MW in 2020-21. Summer operational maximum demand has remained relatively low in the past two years, driven by mild weather conditions which led to lower cooling requirements in Melbourne, and continued uptake of distributed PV. The historical summer maximum operational demand in Victoria was 10,576 MW in 2008-09, before substantial uptake of distributed PV.
  - No directed load shedding or emergency reserves dispatched through Reliability and Emergency Reserve Trader (RERT) in 2021-22.
- Victoria recorded its all-time lowest minimum operational demand of 2,333 MW[23] on 28 November 2021. This was 196 MW lower than the previous record set in 2020-21. This is the fourth consecutive year that the annual minimum demand record has occurred during the daytime. Victorian operational demand fell below the previous record minimum of 2,529 MW on three days in 2021- 22, with all these events occurring during daylight hours in Q4 2021.
  - The installation of the two reactors at Keilor Terminal Station has eliminated the need for operational intervention to manage high voltages despite the increasing number of low demand days.
  - Another two reactors installed at Moorabool Terminal Station in 2022 will provide further headroom in managing network voltages as demand is forecast to reduce further in future.
- AEMO suspended the spot market in all NEM regions between 15 and 24 June 2022, when the number and scale of interventions needed to manage actual and forecast reserve shortfalls made it impossible to continue operating the spot market in accordance with the NER[24]. Prior to the market suspension on 15 June 2022 there were two periods of less than 30 minutes where northerly flows across the Victoria – New South Wales Interconnector (VNI) exceeded secure levels.
- An incident (a line trip due to a lightning strike) on 1 March 2022 resulted in loss of generation in the West Murray Zone.
- Several terminal stations that have historically behaved as net loads increasingly behaved as net generation sources due to increases in distribution-connected generation. This year, 15 locations experienced reverse flows, up from nine locations in 2020-21.

[23] On 2 October 2022, Victoria had already recorded 2,285 MW, which is lower than the record low demand in 2021-22.

[24] For more detail on the events and conditions leading to the suspension, see AEMO's market event and reviewable operating incident report at https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf.

2.1 How does AVP assess 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[25] or other significant incidents which resulted in system security violation or loss of customer load or generation (Section 2.2).
- **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 2.3).
- **Interconnector capability** – the extent to which the operational and design limits of interconnectors restricted the import and export of generation (Section 2.4).
- **Operational challenges** – how network operation was impacted by the changing technical characteristics and geography of supply, particularly where such changes increased operational complexity (Section 2.5).
- **Impact of constraint equations** – the severity of network constraints (Section 2.6).
- **Behaviour of the transmission network at time of high network stress** – a range of case studies examining the performance of the network under extreme operating conditions (Section 2.7).

In this chapter, 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[26].
- Distributed PV refers to PV systems up to 100 kilowatts (kW) capacity.

2.2 Notable power system incidents

Table 2 summarises notable power system incidents in Victoria in 2021-22. The table reflects emerging issues in the Victorian DSN which may develop into investment opportunities in the future. This section does not consider events which occurred primarily within the distribution network.

Of the two incidents shown in Table 2, one relates to issues in the West Murray area, highlighting the ongoing challenges integrating high levels of generation in this weak area of the network. The West Murray Zone is an area of the National Electricity Market with low system strength, extending across parts of Victoria and New South Wales. This area has attracted significant investment in grid-scale solar and wind generation in recent times. The rapid pace of inverter-based renewable generator connections has resulted in new technical challenges, impacting grid performance and operational stability.

The non-credible contingency event on 1 March 2022, with cascade tripping of multiple plant, highlights the challenges in setting protection in weak networks where in-zone and out-of-zone faults become difficult to distinguish.

[25] For the full definition of “reviewable operating incident”, see clause 4.8.15 of the NER. AEMO’s published reports about operating incidents are at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

[26] For further information on demand and consumption definitions, see https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2019/dispatch/demand-terms-in-emms-data-model.pdf?la=en&hash=87701F90591C4DD3065AA00056AA71E8.

The market suspension in June 2022 relates to challenges managing reliability from a bulk energy availability perspective. During this event, the strong interconnection of the DSN with neighbouring regions played a crucial role in sharing reserves and avoiding load shedding. This is reflected by two periods shorter than 30 minutes each on 15 June 2022 when northerly VNI flows exceeded secure limits to maintain supply-demand balance in New South Wales until directed generators could ramp up their output.

Table 2 Summary of curated notable power system incidents in Victoria in 2021-22

Date	Incident	Consequence
1 March 2022	Trip of Red Cliffs – Kiamal 220 kV line, Kiamal synchronous condenser, Buronga No. 2 and No. 3 synchronous condensers	The Murraylink Automatic Very Fast Run Back Scheme initiated. The Generator Fast Trip Scheme 2 (GFT2) triggered and operated as designed to trip Murra Warra Wind Farm, which was generating 110 MW.
10 June to 24 June 2022	NEM market suspension and operational challenges in June	NEM spot market suspended from 1400 hrs on 15 June 2022 to 1400 hrs on 24 June 2022. VNI secure limit determined by voltage collapse constraint exceeded in two periods of less than 30 minutes on 15 June 2022, by a maximum of up to 108 MW.

1 March 2022 – Trip of Red Cliffs – Kiamal 220 kV line, Kiamal synchronous condenser, and Buronga No. 2 and No. 3 synchronous condensers

On 1 March 2022, a three-phase trip and successful auto-reclose of the Red Cliffs (RCTS) – Kiamal (KMTS) 220 kV line occurred due to a lightning strike[27].

The tripping of the RCTS – KMTS 220 kV line initiated the operation of the Murraylink Automatic Very Fast Run Back Scheme, since Murraylink was transferring 140 MW in the direction of South Australia. The Generator Fast Trip Scheme 2 (GFT2) was also triggered and operated as designed to trip Murra Warra Wind Farm, which was generating 110 MW.

As a result of this incident, the Kiamal Solar Farm synchronous condenser and the Buronga No. 2 and No. 3 synchronous condensers tripped unexpectedly. The tripping of the Buronga No. 2 and No. 3 synchronous condensers initiated an inter-trip at Darlington Point Solar Farm as designed. The Darlington Point Solar Farm was not generating at the time it was tripped.

Aside from the tripping of Murra Warra Wind Farm by the GFT2 scheme, there was no further loss of generation or customer load as a result of this incident.

10-24 June 2022 – Market suspension and operational challenges

In June 2022, a confluence of events affecting the interconnected gas and electricity markets saw the automatic application of administered price caps under gas market rules, and then under the NER. A subsequent fall in generation volumes offered into the spot market, combined with a large number of prior outages, led to shortfalls in actual and forecast reserves and required a range of interventions to maintain power system reliability and security. AEMO ultimately suspended operation of the spot market in all NEM regions at 1400 hrs on 15 June 2022, when the number and scale of interventions needed to manage the reserve shortfalls made continued

[27] The report on this incident is expected to be published in late 2022 by AEMO.

operation of the spot market in accordance with the NER impossible. The suspension was formally lifted at 1400 hrs on 24 June 2022[28].

During this period, AEMO worked closely with generators, emergency reserve providers, NSPs and jurisdictions to manage system operations and maintain reliable supply to consumers. AEMO took steps available to it under the NER, such as deferral of network maintenance, generator directions and activation of emergency reserves, while working with jurisdictions and generators to facilitate fuel supply chain interventions and temporary relaxation of restrictions that limited generation capacity. Despite these actions, there were occasions when the market came very close to customer load shedding in mainland regions of the NEM, resulting in periods of low frequency, and interconnectors exceeding secure limits.

AEMO identified that there were two periods of less than 30 minutes in the morning of 15 June 2022 where northerly flows across VNI exceeded secure levels determined by the voltage collapse constraint V^^N_NIL_1 (avoid voltage collapse around Murray for loss of both Alcoa Portland [APD] potlines), as calculated by the NEM Dispatch Engine (NEMDE). Subsequently, AEMO undertook post event analysis using half-hourly system snapshots to determine the maximum northerly VNI flows possible during these times while maintaining power system security for the loss of the APD potlines. The VNI secure limit calculated through post event analysis was slightly higher during this period than the VNI limit calculated by NEMDE, as it does not include the statistical or operating margins of the constraint[29]. Based on the half-hourly system snapshots, the VNI flow exceeded the secure limit by a maximum of 108 MW at 0500 hrs.

2.3 Supply-demand adequacy

The supply-demand balance in Victoria was maintained in 2021-22, with no directed load shedding or emergency reserves dispatched through RERT. Three actual Lack of Reserve (LOR) days – one LOR1 day and two LOR2 days – were declared in Victoria in 2021-22, compared to one LOR1 day in 2020-21, and three LOR2 days and one LOR1 day in 2019-20[30]. All Victorian actual LOR conditions in 2021-22 occurred during the market suspension and operational challenges in June 2022 (see Section 2.2).

The lack of need for emergency mechanisms during system normal conditions indicates that the DSN is continuing to meet consumers' needs. However, planned outages continue to require close coordination to avoid supply-demand challenges, such as on 2 June 2022 when LOR2 conditions were forecast but did not eventuate (see case study).

[28] At https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf.

[29] Constraint equations have both operational and statistical margins. The ability of the constraint equation in NEMDE to maintain the flow on an interconnector or transmission element to within the true limit is dependent on a number of factors including modelling approximations, control limitations, and short-term variations in loads and generator outputs. AEMO determines the operating margins to be applied to constraint equations to manage these approximations and errors – the operating margin for the V^^N_NIL_1 constraint is 50 MW. The statistical margin of a constraint relates to the percentage of critical cases that have less restrictive limits than predicted by the limit equation and the percentage of critical cases that have more restrictive limits. The secure limit calculated through post event analysis does not include the operating margin or the statistical margin of the constraint.

[30] 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.

Case study: Forecast LOR2 conditions on 2 June 2022

On 2 June 2022, an outage was planned on the Dederang – South Morang No. 1 line for delivery of the VNI East RIT-T project. This outage reduced VNI transfer capability into Victoria, and thus prevented available capacity from New South Wales and Queensland from reaching southern NEM states. LOR2 conditions were forecast across the morning peak simultaneously in Victoria, Tasmania, and South Australia with a 19-hour lead time due to this reduced transfer capability. The forecast LOR2 conditions were subsequently cleared in all states following a recall of this outage, allowing northern NEM states to share their excess capacity with southern NEM states.

This case study highlights both the significant role that Victoria's central interconnection plays in reliability across all NEM states, and the consequent difficulty of finding adequate outage windows for maintenance and augmentation. The outage was able to safely go ahead the following day, on 3 June 2022.

2.3.1 Victorian demand

The annual peak Victorian operational demand in 2021-22 was 8,599 MW on 27 January 2022 at 18:00, compared to 8,411 MW in 2020-21.

Victorian maximum operational demand has remained relatively low in 2020-21 and 2021-22 compared to the 9,852 MW summer maximum in 2019-20. This is due to comparatively milder La Niña weather conditions in 2020-21 and 2021-22, which have led to lower cooling requirements in Melbourne[31], along with continued uptake of distributed PV.

The 2022 VAPR marks the first time that annual maximum demand has occurred after 17:00, as a result of increasing distributed PV generation offsetting the underlying operational demand. It is estimated that without distributed PV generation, Victorian operational maximum demand may have been 600-1,000 MW higher each year between 2016-17 and 2021-22.

Winter maximum operational demand has continued to increase over the past five years, to 8,158 MW on 31 May 2022, the highest since 2011. Victoria experienced very cold weather in late May and early June, with some sites in Victoria experiencing their coldest May day on record[32]. Further, distributed PV contributes less to demand in winter, meaning that other drivers of demand growth such as population and economic growth, dominate.

In Victoria, annual maximum demand has historically occurred in summer due to high cooling load on hot days. The projected electrification of traditional gas loads, particularly heating loads in Victoria, is expected to increase forecast consumption and maximum demands in winter. For Victoria in particular, the 2022 ESOO Central scenario forecasts winter peak demands may exceed summer peak demands by the end of the decade.

[31] See AEMO, *Quarterly Energy Dynamics Report* Q4 2021, at https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf?la=en.

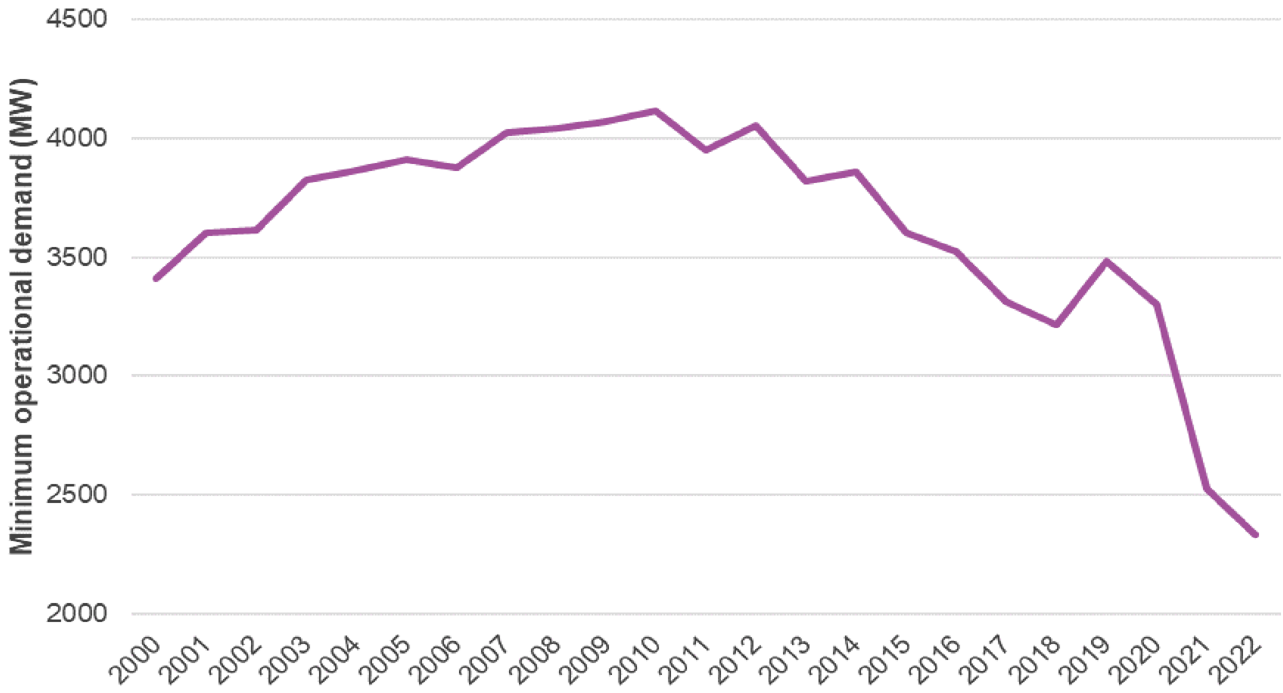
[32] See https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q2-2022.pdf?la=en.

Figure 7 Actual maximum summer (1 Oct – 31 Mar) and winter (1 Apr – 30 Sep) Victorian operational demand, 2000 to 2022

Victoria recorded its all-time lowest minimum operational demand of 2,333 MW on 28 November 2021 at 13:00. This was 196 MW lower than the previous record set last year. This is the fourth consecutive year that the annual minimum operational demand record has occurred during the day time, and this trend is forecast to continue. Victorian operational demand fell below the previous record minimum of 2,529 MW on three days in 2021-22, with all these events occurring during daylight hours in Q4 2021.

Annual minimum demand in Victoria has historically occurred when human activity was at its lowest: between 04:00 and 06:00 on a major public holiday. This was the case every year from the beginning of operational demand records in 1998 up to 2015. Since 2019, minimum demand has instead occurred between 12:00 and 13:30 in late spring to early summer, when distributed PV generation is at its highest.

Figure 8 Actual minimum Victorian operational demand 2000 to 2022



2.3.2 Victorian supply

The total large-scale installed generation capacity in Victoria increased to 15.1 GW by June 2022, as a result of approximately 2.4 GW of newly connected large-scale wind, solar, and battery projects (see sections 3.1 and 3.3).

Despite this, Victoria experienced significant challenges in managing the available capacity in Q2 2022 in the lead up to and during the market suspension (see Section 2.2). Available capacity for scheduled generation was limited by the following factors:

- Gas generation faced a shortage of gas supply due to record demand by multiple Victorian generators and challenging winter supply-demand dynamics in the gas market.
- Despite low coal-fired generation output, and La Niña-driven rainfall raising upstream storage levels[33], hydro generation at some key generators was limited by downstream hydrological constraints that were also linked to wet conditions.
- Brown coal generation faced high levels of unplanned outages. Loy Yang A Unit 2 was taken out of service on 15 April 2022 due to a generator electrical failure, and is expected to remain out of service until the end of October 2022 due to global supply chain issues and availability of specialised materials[34].
- Prior to the market suspension, the available capacity of Yallourn Power Station was limited by extended outages of nearby 220 kV lines for most of 2022. The Hazelwood – Yallourn No. 1 and No. 2 220 kV lines experienced extended outages from 11 June 2021 to 6 May 2022 due to repair and maintenance works to the Morwell River Diversion wall (MRD)[35] at the Yallourn mine, limiting the output at Yallourn Power Station.

[33] Snowy Hydro 2022, Dam Levels, at https://www.snowyhydro.com.au/generation/live-data/lake-levels.

[34] AGL 2022, LYA2 Generator Fault – Update on expected return to service, at https://www.agl.com.au/about-agl/media-centre/asx-and-media34releases/2022/june/loy-yang-a-unit-2-generator-fault---update-on-expected-return-to.

[35] See https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-statement-yallourn-mine.

2.4 Interconnector capability

An interconnector's capability depends on the conditions within the network, which vary throughout the year. AEMO publishes notional interconnector limits in its Interconnector Capabilities Report[36], and a detailed summary of the capability and limits of each interconnector in the NEM in its Monthly and Annual NEM Constraint Reports[37].

Table 3, Table 4 and Figure 9 provide an indication of 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 duration of Victorian power export to neighbouring mainland regions. A reversal of this trend was observed in 2020-21 and continued in 2021-22, with net exports into neighbouring regions increased significantly from the previous year.

Table 3 Percentage (%) of time interconnectors export energy from Victoria, pre-Hazelwood closure to 2021-22

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

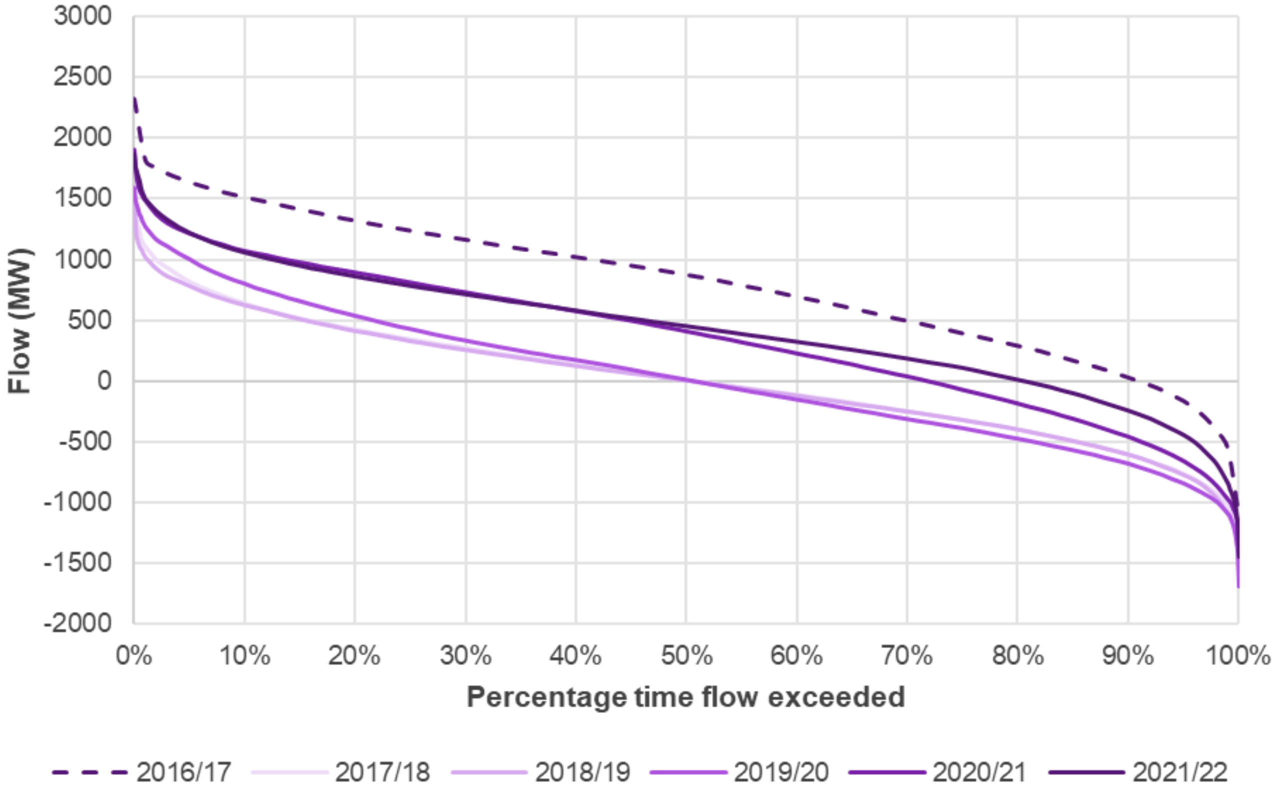
Table 4 Net energy exported from Victoria (gigawatt hours [GWh]), pre-Hazelwood closure to 2021-22

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

[36] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2017/Interconnector-Capabilities.pdf.

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

Figure 9 Victoria net interconnector flow duration curve (all interconnectors)



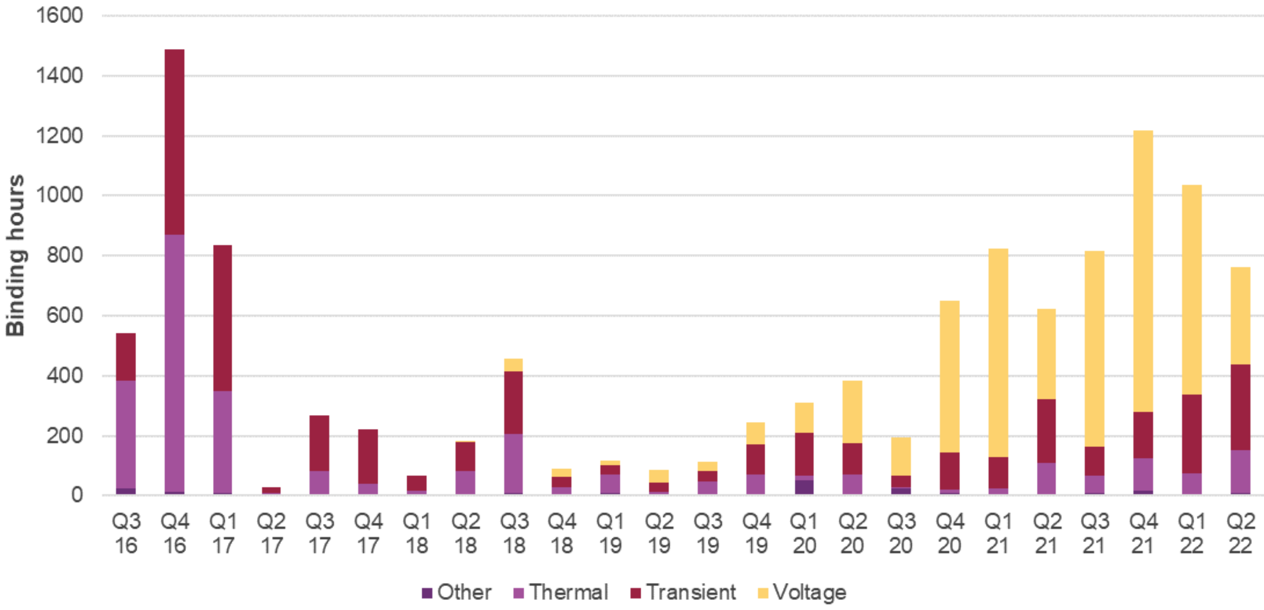
While the percentage of time VNI spent exporting in 2021-22 increased to be similar to pre-Hazelwood retirement levels, new voltage collapse constraints which have been introduced progressively since 2018 limited the magnitude of VNI exports in 2021-22.

Binding hours for voltage collapse constraints bound significantly more in 2021-22 than previous years, due to:

- Commissioning of large-scale solar in New South Wales which caused a new voltage collapse constraint to bind.
- Reformulation of an existing voltage collapse constraint in February 2021.
- A significant number of network outages which have reduced the headroom of voltage collapse constraints.

The voltage collapse constraints responsible for these binding hours are explored in detail in Section 2.6.

Figure 10 Historical binding hours for export constraints along VNI by constraint type, Q3 2016 to Q2 2022



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[38]. The maximum transfer currently allowed is 600 MW from Victoria to South Australia, and 500 MW from South Australia to Victoria. These limits have prevented Heywood from finishing its inter-regional testing program following major upgrades to the interconnector in 2015-16.

Heywood flows from South Australia to Victoria were constrained further to 420 MW from 17 July 2020, due to the permanent failure of the Parafield Gardens No. 1 static Var compensator (SVC) due to a fire. The No. 1 SVC was replaced and returned to service in December 2021, however a subsequent unrelated fault and permanent failure of the No. 2 SVC transformer occurred one month later, on 4 January 2022, which required this 420 MW limit to be reinvoked. This constraint was binding for 2.5% of 2021-22 and is expected to remain in place until the SVC transformer is fully replaced (scheduled for August 2023).

Notably in Q1 2022, high solar generation in the Murray River REZ caused the Murraylink direct current (DC) interconnector to carry its highest ever level of Q1 net average flow from Victoria into South Australia (86 MW), accounting for nearly half of the net average flow between these regions[39].

2.5 Operational challenges

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

[38] AEMO, *Black System in South Australia, 28 September 2016*, March 2017, listed under 2016 reports at https://www.aemo.com.au/energy-systems/electricity/ national-electricity-market-nem/nem-events-and-reports/power-system-operating-incident-reports.

[39] See https://aemo.com.au/-/media/files/major-publications/qed/2022/qed-q1-report.pdf?la=en.

2.5.1 West Murray considerations

Voltage oscillations under prior outage conditions

AEMO continues 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 increased year on year, reaching record highs in 2021-22 as indicated in Section 2.6. In 2021-22, some of these outages were related to upgrade works during July and August 2021 along Red Cliffs – Wemen – Kerang to remove station limiting equipment and improve thermal constraints in the V2 Murray River REZ.

Network outages in the West Murray area are expected to continue in coming years to deliver upcoming network augmentations including the Western Renewables Link and Project EnergyConnect. AEMO will review the need for these voltage oscillation constraints after the completion of these augmentations.

Sub-synchronous oscillations

Sub-synchronous oscillations[40] (16-19 hertz [Hz]) were first observed in 2020 and have typically been intermittent and low in magnitude (around 0.5% peak to peak voltage at Red Cliffs Terminal Station (RCTS)), lasting from under a minute to several minutes.

Sub-synchronous oscillations have been observed during an outage of the Red Cliffs to Buronga 220 kV line (OX1 line) and during periods when Murraylink was disconnected, indicating the likely source of oscillations within north-west Victoria[41].

AEMO is working with relevant NSPs to install appropriate monitoring equipment across the West Murray area, and is engaging with NSPs, market participants, and the broader power system engineering community nationally and internationally to identify and, where possible, resolve issues. A project is progressing to replace and expand the existing network of aging High Speed Monitors (HSMs) around Victoria with modern Phasor Measurement Units (PMUs).

2.5.2 System strength shortfall

The Red Cliffs system strength shortfall has now been addressed through system strength service contracts that will remain in place until at least mid-2025.

AEMO's *Update to 2021 System Security Reports*[42] declared a system strength shortfall of 203 megavolt-amperes (MVA) at Hazelwood from mid-2026, 31 MVA at Moorabool from mid-2026, and 279 MVA at Thomastown from mid-2026. This timing was driven by the projected early retirement of Yallourn Power Station in 2026 in the ISP *Step Change* scenario.

AVP is progressing activities to address the system strength shortfall declarations and, since these declarations, has also contracted for services to strengthen the system in both the Murray River REZ and Western Victoria REZ as part of the Victorian Government's RDP Stage 1 projects, as further detailed in Section 3.4.3.

[40] For more information, see AEMO's "Sub-Synchronous Oscillations in the West Murray Area" presentation, at https://aemo.com.au/-/media/files/electricity/nem/network_connections/west-murray/sub-synchronous-oscillations-in-the-west-murray-area.pdf?la=en.

[41] For more information, see AEMO's West Murray Zone Sub-Synchronous Oscillations report https://aemo.com.au/-/media/files/electricity/nem/network_connections/west-murray/high-level-summary-of-wmz-subsynchronous-oscillations.pdf?la=en.

[42] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/update-to-2021-system-security-reports.pdf?la=en.

2.5.3 Impact of record minimum demand

Distributed PV

Figure 11 shows the demand profile and impact of distributed PV generation on the day of annual minimum operational demand, 28 November 2022. At the time of minimum operational demand of 2,333 MW, distributed PV had an aggregate output of over 2,300 MW, offsetting nearly 50% of underlying demand. Without the effect of distributed PV, minimum demand on this day would have occurred at 04:00 at 3,707 MW.

Figure 11 Victorian demand profile on minimum demand day (28 November 2021)

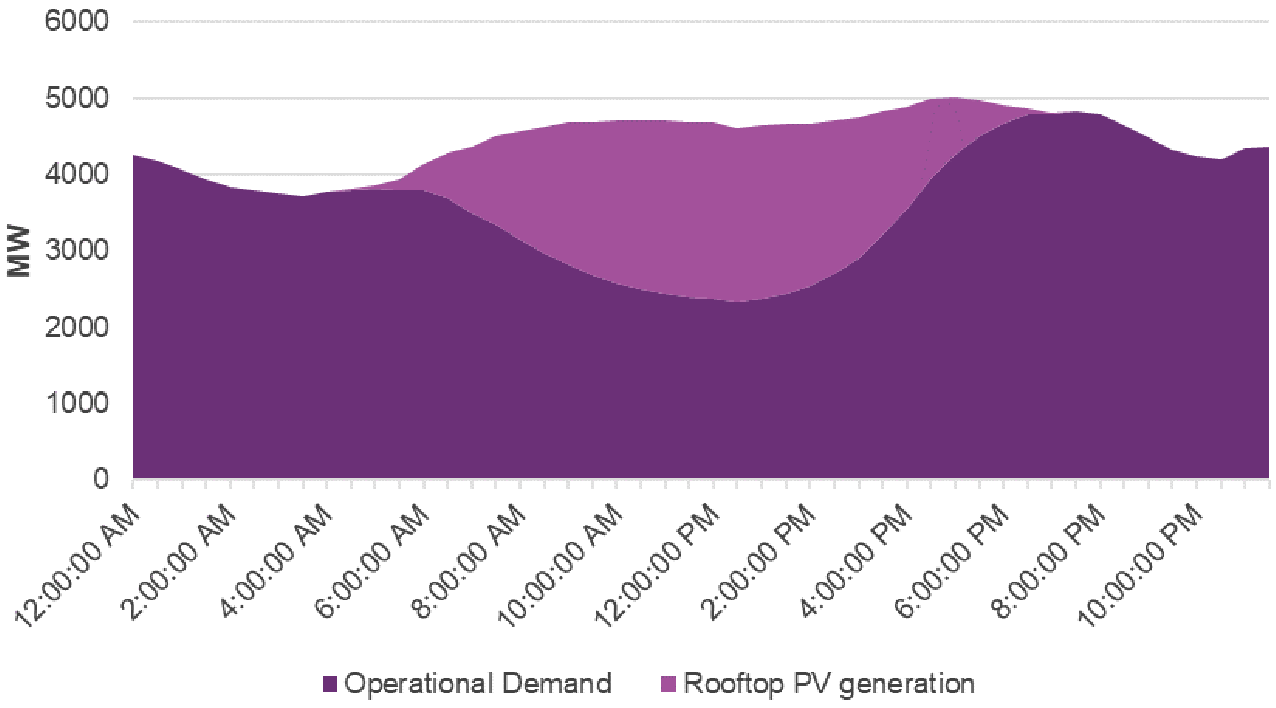


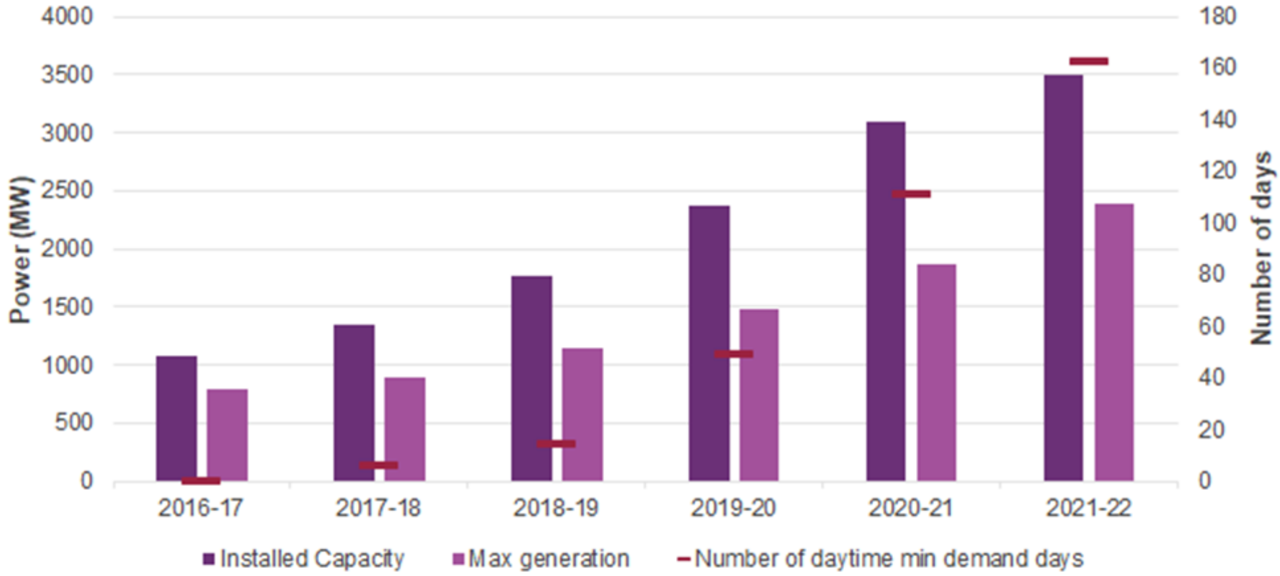
Figure 12 below[43] shows the number of days each financial year on which daily minimum operational demand occurred during daylight hours (08:00 to 17:00) in the last five years. This occurred on 162 days in 2021-22 compared to 111 days in 2020-21 and 51 days in 2019-20.

Approximately 385 MW[44] of distributed PV has been installed in Victoria since September 2021.

[43] Distributed PV generation and capacity according to 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.

[44] 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 31 July 2022.

Figure 12 Distributed PV capacity and maximum generation by financial year and number of daytime minimum demand days, 2016-17 to 2021-20



Voltage management

Under minimum demand conditions, and without operator intervention, high voltages can occur on the Victorian transmission network. Short-term operational measures, such as de-energising a 500 kV transmission line, have become normal practice during these periods to maintain system voltage requirements. Projected reductions in minimum demand over the next decade, linked with rapid uptake in distributed PV, will act to further exacerbate this issue.

Reliance on voltage control interventions results in higher market costs, reduced system resilience, and higher system security risks. Table 5 summarises the frequency with which these measures have been used for voltage control over the past two years.

Table 5 Historical frequency of operational measures to manage high voltages

Operational measures	Number of times action was taken											
	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022
De-energise first 500 kV line	14	29	15	14	10	20	3	6	10	9	0	0
Activate NMAS[A]	0	17	20	14	6	25	7	0	6	4	0	0
De-energise second 500 kV equipment	0	2	2	2	1	5	0	0	0	0	0	0
Issue directions	0	0	1	0	0	0	0	0	0	0	0	0
Total actions	14	48	36	30	17	50	10	6	16	13	0	0
	128				83				29			

A. In March 2019, AVP entered a short-term NMAS agreement for voltage control support at times of minimum demand. This contract ceased in April 2022.

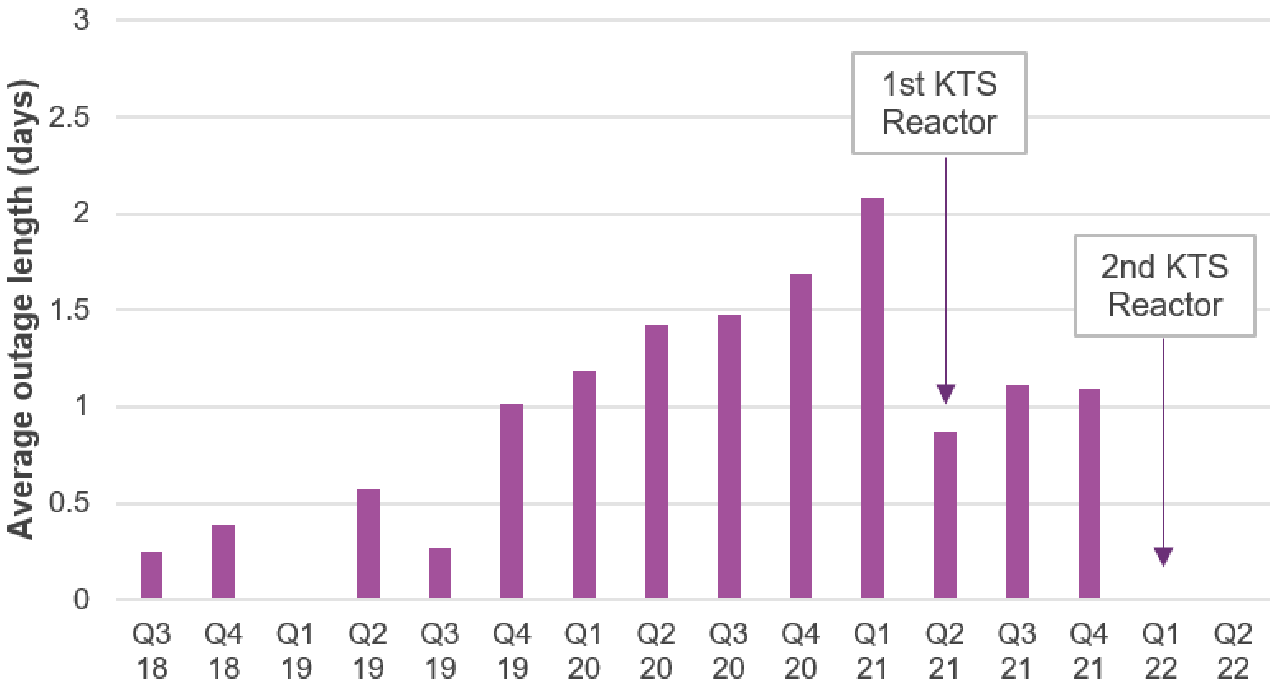
The following solutions have been utilised to manage network voltages since 2019:

- In 2019, AVP entered into an NMAS agreement with a generation proponent to provide additional reactive capabilities on request. AVP used this contract operationally while long-term solutions were in the process of being delivered. This contract ended in April 2022.
- In 2020, AVP and AusNet Services agreed to upgrade an over-voltage protection scheme to increase the permitted 500 kV post contingent voltage at Keilor. This was also an interim measure as network solutions were being delivered.
- In April 2021, a 100 megavolt-amperes reactive (MVAr) 220 kV reactor was installed by AusNet Services as part of a Network Capability Incentive Parameter Action Plan (NCIPAP) at Keilor Terminal Station (KTS).
- In December 2021, a second 100 MVAr 220 kV reactor was installed at KTS as part of a RIT-T completed by AVP in December 2019.
- In July-August 2022, two 100 MVAr 220 kV reactors were installed at Moorabool Terminal Station (MLTS) as part of a RIT-T completed by AVP in December 2019.

The new reactors at KTS and MLTS have significantly reduced the requirement for operational intervention to manage high voltages in Victoria.

Figure 13 shows that the average duration of 500 kV line outages required to manage high voltages dropped sharply in Q2 2021 on commissioning of the first reactors at KTS, and no intervention was required after the second reactor at KTS was commissioned in Q1 2022. It is worth noting that conditions which lead to high voltage are more likely to occur in Q3 and Q4, so intervention may still be required even with the new reactors in place in future, particularly if minimum demand continues to decline as expected.

Figure 13 Average duration of periods during which 500 kV lines are switched out to manage high voltage during low demand, Q3 2018 to Q2 2022

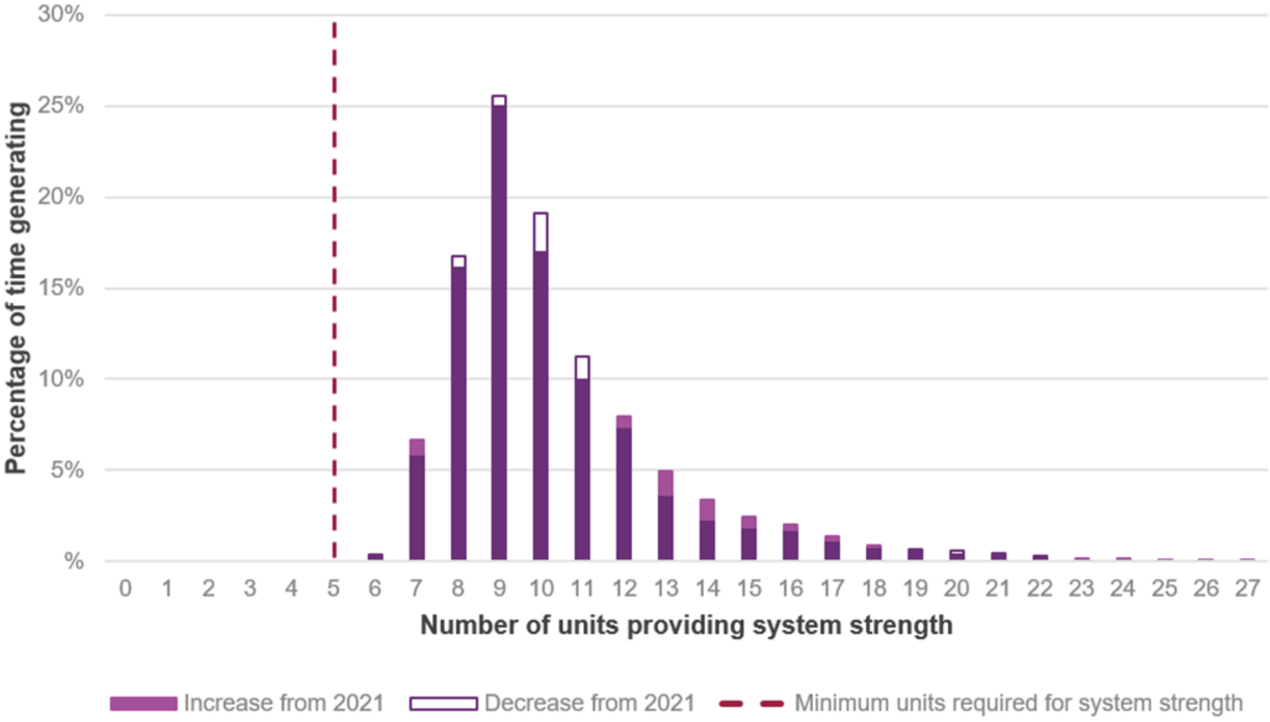


Minimum synchronous units to maintain system strength

As described in the 2021 VAPR, lower numbers of concurrent synchronous units have been observed in operation during increasingly low minimum demand periods. Currently a minimum of five synchronous units are required to maintain the minimum level of system strength in Victoria[45].

Figure 14 shows, over the last 12 months, the frequency of units online that are capable of providing system strength. In 2021-22, Victoria spent 4% more time operating with 12 or more system strength units in service than it did in 2020-21. A large portion of this increase occurred during June 2022 when many peaking gas and hydro units were frequently online to manage operational challenges during the market suspension. While more system strength units were online in 2022 overall, the time spent at the lowest end of the spectrum – with seven or fewer units online – slightly increased by 0.6% compared to 2020-21.

Figure 14 Available system strength units during 2021-22, and compared to 2020-21



As minimum demand continues to fall, this curve is expected to shift to the left, increasing the risk of system strength interventions to maintain the required number of synchronous units online. In the 2021 VAPR, AVP identified that below 800 MW of operational demand, Victoria must export to neighbouring regions to maintain a minimum number of units for system strength. The 2022 ESOO Central forecast projects minimum operational demand in Victoria falling below this 800 MW threshold as early as 2027-28. Future network investment may be required to remediate this issue, and AEMO is monitoring these needs through an annual outlook of system strength issues (see Section 4.5.2).

[45] See AEMO's latest system strength combinations for Victoria at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice.

2.5.4 Reverse power flows

Over the past decade, the increasing volume and geographic distribution of large-scale generators connecting within the sub-transmission and distribution network has caused some terminal stations, which have historically behaved as net loads, to increasingly act as net generation sources to the transmission network. Section 3.1 lists the supply changes since the 2021 VAPR was published. These 'reverse flows' have impacts on the performance of load shedding control schemes and voltage control. In planning the Victorian DSN, AVP regularly reviews the load shedding control schemes to avoid tripping feeders with reverse flows and ensure sufficient reactive power support is available for voltage control. See section 4.8 and 4.5.4 for more information about review of control schemes and voltage management.

The frequency and magnitude of reverse power flows has continued to increase in Victoria, with 15 terminal stations experiencing such flows in 2021-22. This was up from nine terminal stations reported in the 2021 VAPR, and with increased or similar durations observed across most stations.

Of the six additional terminal stations experiencing reverse flows, five are due to the cumulative installation of distributed PV, primarily on rooftops in the distribution network behind each terminal station. This is the first year in which significant reverse flows through some terminal stations have been observed primarily due to distributed PV generation with no distribution-connected large-scale generators driving the reverse flows.

Table 6 outlines the number of hours that reverse flows occurred at these 15 terminal stations over the last four years and notes the associated primary cause of reverse flows at each location.

Table 6 Reverse flow statistics at identified locations

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

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

Significant changes in reverse flow hours at each terminal station are attributed to:

- Increased distributed PV generation at Wodonga, Morwell, Deer Park, Cranbourne, and Bendigo terminal stations.
- Horsham Terminal Station (HOTS) broke the decreasing trend in reverse flow hours of the previous three years. Diapur Wind Farm (7 MW) was connected to the 22 kV network behind HOTS in Q3 2021.
- Terang Terminal Station (TGTS) saw a small increase in reverse flows in 2022. Ferguson North and South wind farms (10 MW) were connected to the 22 kV network behind TGTS in Q4 2020 and Q2 2021.
- Glenrowan Terminal Station (GNTS) significantly increased its reverse flow hours from 2020-21 levels as the 66 kV-connected Winton Solar Farm (85 MW) and Glenrowan West Solar Farm (110 MW) both completed hold-point testing and were released to generate unconstrained.
- Mount Beauty Terminal Station (MBTS) saw a return to significant periods of reverse flows in 2022 for the first time since 2018-19. This was due to both significantly increased generation from Clover hydro power station (29 MW), and additional power flowing from GNTS solar farms into MBTS via the 66kV tie between them.
- Wemen Terminal Station (WETS) saw a small decrease in reverse flow hours in 2022 compared to previous years. Wemen and Bannerton solar farms, connected to the 66 kV network behind WETS, were affected by outage constraints during November and December 2021.

Injections into the transmission network from distribution networks are expected to grow over time, particularly as further generation projects connect and DER offsets local demand to create periods of surplus supply in the distribution network. This will present new operational and network planning challenges to both TNSPs and distribution network services providers (DNSPs). Currently runback schemes to manage n-1 loading of distribution transformers are in place at six terminal stations, and constraints to manage n loading of distribution transformers are in place at two terminal stations.

2.6 Impact of Victorian transmission constraints

This section summarises the Victorian transmission network constraints that resulted in the top 20 highest dispatch impacts during the 2021-22 financial year. Comparison values are also shown for the 2020-21 financial year.

The ranking of each constraint (or group of constraints) is 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.

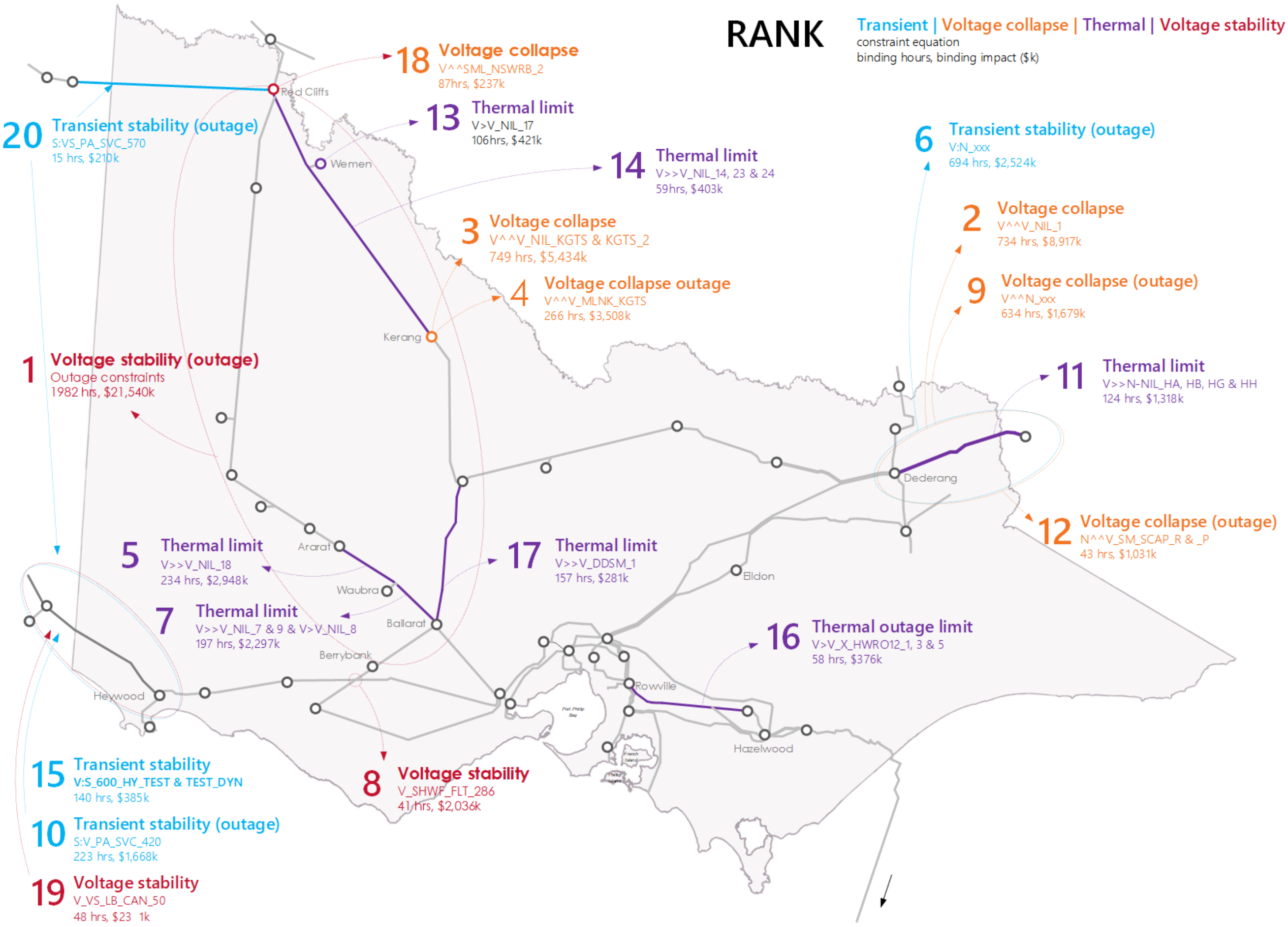
Figure 15 summarises these constraints by type and location around the Victorian system, as well as binding hours and constraint impacts in dollars.

While the constraints summarised in this section are those with the most significant 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 15 would not result in unconstrained flows along Wemen to Kerang, as this line is also limited by constraint 14. In other parts of the region, constraints that currently do not bind at all may begin to bind as other limits are removed.

To assess the true benefits of relieving constraints, AEMO undertakes detailed power system and economic modelling through prefeasibility and RIT-T processes (see Chapter 4).

Figure 15 Map of the most significant Victorian transmission constraints in 2021-22



Note: 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 represents a collection of prior outage limitations that applied during a set of planned network outages in the north-west of Victoria.

Western Victoria and Murray River REZs

The transmission network in the west of Victoria and in the Murray River REZs has been characterised by significant new renewable generation investment, and accompanying outages to facilitate connection and commissioning of these projects. This is a relatively weak part of the network, subject to thermal, voltage stability and voltage collapse constraints that have bound more frequently and with higher market impact in 2021-22 compared with 2020-21, as new generators have connected in this area.

Table 7 presents further information on these limitations.

Table 7 Equations with significant binding durations or impact – western Victoria and Murray region

Rank	Equation	Binding hours		Binding impact		Description of constraint
		2020-21	2021-22	2020-21	2021-22	
1	North-west Victoria voltage stability (prior outage)	1081[A]	1982[A]	$12,568k[A]	$21,540k[A]	A set of the network constraint equations associated with voltage oscillation during a range of prior outage conditions. Some of these constraints were invoked in July and August 2021 to accommodate the installation of wind monitoring at Wemen to Kerang Terminal Stations. AEMO is continuously reviewing these constraints based on upcoming outage schedules as revised models are obtained. The Koorangie Energy Storage System (KESS), which as part of the Victorian Government's RDP Stage 1 projects has been contracted by AVP to provide system strength services, is expected to reduce the impact of these constraints for most outages.
3	Wemen to Kerang voltage collapse V^^V_NIL_KGTS and V^^V_NIL_KGTS_2	67	749	$547k	$5,434k	To limit post-contingency flow on Wemen to Kerang for loss of Horsham to Murra Warra to Kiamal or Horsham to Bulgana to Crowlands to avoid voltage collapse. In September 2021 both constraints were reformulated into V^^V_NIL_KGTS. This constraint has bound more frequently post reformulation. Changes made to the Murraylink very fast runback scheme in September 2022 are expected to reduce the impact of this constraint.
4	Wemen to Kerang voltage collapse V^^V_MLNK_KGTS	-	266	-	$3,508k	To limit post-contingency flow on Wemen to Kerang for loss of Horsham to Murra Warra to Kiamal or Horsham to Bulgana to Crowlands to avoid voltage collapse during an outage of Murraylink. This constraint had the largest market impact during two major Murraylink outages in December 2021 lasting 18 days, and May 2022 lasting 11 days.
5	Ararat to Waubra Thermal V>>V_NIL_18	148	234	$358k	$2,948k	To prevent post-contingent overload of Ararat to Waubra 220 kV on trip of Kerang to Bendigo 220 kV. Minor augmentations, being undertaken as part of the Victorian Government's RDP Stage 1 projects, will 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 from 2025.
7	Waubra Terminal Station (WBTS)-Ballarat Terminal Station (BATS) Thermal V>>V_NIL_7[C], V>V_NIL_8 and V>>V_NIL_9.	203	197	$631k	$2,297k	Avoid overloading the Waubra to Ballarat 220 kV line on trip of the Red Cliffs to Wemen to Kerang 220 kV line or Kiamal to Red Cliffs 220 kV line or Kerang to Bendigo 220 kV line. Minor augmentations, being undertaken as part of the Victorian Government's RDP Stage 1 projects, will 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 from 2025.
13	Wemen Transformer thermal[B] V>V_NIL_17	441	106	$4,075k	$421k	Prevent pre-contingent overload of Wemen 220/66 kV transformer in the 66 to 220kV direction (not part of DSN).
14	Wemen to Kerang Thermal V>>V_NIL_14, V>>V_NIL_23[D], and V>>V_NIL_24[D]	44	59	$352k	$403k	To prevent post-contingent overload of Red Cliffs to Wemen to Kerang 220 kV on trip of Horsham to Murra Warra to Kiamal 220 kV (V>>V_NIL_14) or Crowlands to Bulgana to Horsham 220 kV (V>>V_NIL_23, 24). V>>V_NIL_14 was invoked in August 2020, and V>>V_NIL_23 and 24 invoked in March 2021.

Rank	Equation	Binding hours		Binding impact		Description of constraint
		2020-21	2021-22	2020-21	2021-22	
						A NCIPAP project to remove station limitations at Wemen and Kerang Terminal Stations and install windspeed monitoring on the Wemen to Kerang line, was completed in August 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 at similar levels to 2020-21.
18	Red Cliffs voltage collapse V^^SML_NSWRB_2	53	87	$292k	$237k	To avoid voltage collapse at Red Cliffs for the loss of Darlington Point to Balranald (X5) or Balranald to Buronga (X3) 220 kV lines when the New South Wales Murraylink runback scheme is unavailable. The Koorangie Energy Storage System (KESS) , which as part of the State Government's RDP Stage 1 projects has been contracted by AVP to provide system strength services, is expected to reduce the impact of this constraint.

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. V>>V_NIL_7 first came into effect in September 2020.
D. V>>V_NIL_23 and V>>V_NIL_24 first came into effect in March 2021

South West corridor and the Heywood interconnector

New constraints have emerged in the South West corridor in 2022, as well as existing constraints binding 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 of South Australia.

Table 8 provides further details on each of these limitations.

Table 8 Equations with significant binding durations or impact – south-west corridor

Rank	Equation	Binding hours		Binding impact		Description
		2020-21	2021-22	2020-21	2021-22	
8	Stockyard Hill Wind Farm system strength V_SHWF_FLT_286[A]	-	41	-	$2,036k	Limit generation at Stockyard Hill wind farm to 286 MW for system strength when Heywood flows from South Australia to Victoria are greater than 400 MW. The Heywood transfer threshold for this constraint was increased from 400 MW to 450 MW in July 2022.
10	Heywood transient stability PARA SVC outage S:V_PA_SVC_420	420	223	$360k	$1,668k	Limit Heywood flows from South Australia to Victoria to 420 MW during an outage of the No. 1 or No. 2 Parafield Gardens SVC. see section 2.4 for further information.
15	Heywood transient stability V:S_600_HY_TEST and V:S_600_HY_TEST_DYN	34	140	$22k	$385k	This constraint represents a 600 MW transfer limit on Victoria to South Australia to ensure oscillatory stability.
19	Heywood system strength during risk of separation V:VS_LB_CAN_50	98	48	$76k	$231k	Limit Canunda Wind Farm, Lake Bonney Wind Farm, and Heywood flows from South Australia to Victoria to 50 MW to maintain system strength during credible risk of South Australia separation. Delivery of Project Energy Connect will significantly reduce the risk of South Australia separation, reducing the frequency with which this constraint is expected to bind in future.

Rank	Equation	Binding hours		Binding impact		Description
		2020-21	2021-22	2020-21	2021-22	
20	Heywood and Murraylink combined transient stability during PARA SVC outage S:VS_PA_SVC_570	33	15	$24k	$210k	Limit Heywood and Murraylink combined flows from South Australia to Victoria to 570 MW during an outage of the No. 1 or No. 2 Parafield Gardens SVC. See Section 2.4 for further information.

A. This is a new constraint effective from December 2021.

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

Constraints in the east of Victoria are dominated by limitations across the VNI. There are several thermal constraints limiting flows between South Morang and Murray, while voltage and transient stability limits flows across the border region.

The binding hours and binding impact of VNI constraints has markedly increased in 2021-22 compared to previous years due to both reformulations of voltage stability constraints, and a number of high-impact outages in both the Victorian and New South Wales regions. Transient stability outage constraints were mainly driven by outages of the Dederang to South Morang 330kV lines and the South Morang series capacitors required to deliver the VNI East project, while voltage stability outage constraints were driven by outages required for maintenance, connecting new generation, and other transmission augmentations.

Notably, outages of Latrobe Valley 500 kV lines required for voltage control reduced significantly in 2021-22 following the delivery of reactors at Keilor Terminal Station (see Section 2.5.3). Unlike previous years, outages of Latrobe Valley 500 kV lines were not significant drivers of outage constraints across the VNI.

In 2022, Yallourn Power Station was impacted by thermal constraints on the 220 kV lines between Yallourn and Rowville terminal stations during a major outage of the Hazelwood to Yallourn No. 1 and 2 220 kV lines. This outage was in place for the majority of 2021-22, with short periods of return to service during January 2022 to manage reliability during summer. This outage was required to allow repair works of the Morwell River Diversion structure in close proximity to these lines following the Morwell River flooding event in June 2021.

Table 9 provides further details on each of the above limitations.

Table 9 Equations with significant binding durations or impact – Eastern Victoria

Rank	Equation	Binding hours		Binding impact		Description
		2020-21	2021-22	2020-21	2021-22	
2	VNI voltage collapse V^^N_NIL_1	689	734	$766k	$8,917k	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 South West Victoria. This constraint was reformulated several times between Sep 2020 an Feb 2021 since when this constraint has bound more frequently.
6	VNI export transient stability during outages V::N_xxx	402	694	$139k	$2,524k	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 330kV lines and South Morang series capacitors in 2022.

Rank	Equation	Binding hours		Binding impact		Description
		2020-21	2021-22	2020-21	2021-22	
						The market impact of transient stability outage constraints is expected to reduce in future following completion of the VNI East project.
9	VNI export voltage collapse during outages V^^N_xxx	453	634	$306k	$1,679k	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, with up to a 200 MVA reduction to the RHS. These constraints are invoked during outages of any line in or connecting to the 330kV corridor between Victorian and NSW capital city load centres. Outages of other significant lines including 500kV Latrobe Valley lines in Victoria and 220kV lines in South West NSW also may require such constraints to be invoked with a smaller reduction to the RHS.
11	VNI thermal overload V>>N-NIL_HA, V>>N-NIL_HB, V>>V_NIL_HG, & V>>V_NIL_HH	43	124	$335k	$1,318k	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.
12	VNI import voltage collapse during South Morang series capacitor outage N^^V_SM_SCAP_R & N^^V_SM_SCAP_P	-	43	-	$1,031k	To avoid voltage collapse in Southern NSW for loss of Victorian largest generator or Basslink during an outage of the South Morang series capacitors. The market impact of these outage constraints is expected to reduce in future following completion of the VNI East project.
16	Yallourn to Rowville 220kV thermal overload during Hazelwood to Rowville 220kV outage V>V_X_HWRO12_1, V>V_X_HWRO12_3, & V>V_X_HWRO12_5	-	58	-	$376k	Avoid overload of the Yallourn to Rowville No. 5, 6, 7 or 8 lines for loss of a parallel line during an outage of Hazelwood to Rowville No. 1 and 2 220kV lines. The Hazelwood to Rowville No. 1 and 2 220kV lines were out of service for most of 2022 to allow repair works of the Morwell River Diversion Structure following flood damage in June 2021. These works have been completed and the lines returned to service.
17	Dederang to South Morang Thermal V>>V_DDSM_1	64	157	$122k	$281k	To avoid overloading the Bendigo to Ballarat 220kV line during an outage of a Dederang to South Morang 330kV line for loss of the other Dederang to South Morang 330KV line. This constraint continued to bind frequently in 2022 due to outages required to deliver the VNI East augmentation works.

2.7 Network performance at times of high network stress

To understand how the network performed at times of high stress, AVP has identified a series of snapshots which assess network stress, giving a comprehensive picture of network performance. These snapshots focus on network stress arising from demand, VNI exports, wind generation, and solar generation, and assess periods in which these quantities were at their most extreme or most limited by network conditions.

AEMO's Engineering Framework[46] identified six future operating conditions for the NEM as the network heads towards 100% instantaneous penetration of VRE – fewer synchronous generators online, ubiquitous rooftop solar,

[46] See AEMO's *Engineering Framework Operational Conditions Summary* report at https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/nem-engineering-framework-july-2021-report.pdf?la=en&hash=04E2BEFE4A1A7281B6294B1C8228AD59.

extensive grid-scale VRE, structural demand shifts, responsive demand, and widespread energy storage. In Victoria, some of these operating conditions are beginning to emerge under network stress (see Table 10). This discussion is complemented by additional information in the historical DSN rating and loading workbook[47].

Table 10 Summary of snapshots

Snapshots	Conditions	Snapshot date and time	Engineering Framework operational condition
Demand	Maximum Victorian demand	27/01/2022 18:00	
	Minimum Victorian demand (daytime)	28/11/2021 13:00	• Fewer synchronous generators online • Ubiquitous rooftop solar
	Minimum Victorian demand (night-time)	26/12/2021 04:00	• Fewer synchronous generators online
Wind	Maximum wind generation in Victoria	14/06/2022 23:30	• Extensive grid-scale VRE
Solar	Maximum solar generation in V2 Murray REZ	26/10/2021 13:00	• Extensive grid-scale VRE
Interconnectors	Maximum export through VNI	15/06/2022 06:30	

2.7.1 Demand

Table 11 compares the overarching DSN conditions during each operational demand snapshot. Further detail of conditions during each demand snapshot is provided in Appendix A5.

Table 11 Victoria demand case study summary of operating conditions

Characteristic	Maximum demand	Daytime minimum demand	Night-time minimum demand
Date and time	27/01/2022 18:00	28/11/2021 13:00	26/12/2021 04:00
Victorian operational demand	8,599 MW	2,333 MW	3,485 MW
Distributed PV	266 MW	2,283 MW	0 MW
Net power flow into Victoria via interconnection*	998 MW • 813 MW from NSW • 136 MW to SA • 321 MW from TAS	-1,042 MW • 785 MW to NSW • 215 MW from SA • 472 MW to TAS	-1,049 MW • 722 MW to NSW • 150 MW from SA • 487 MW to TAS
Victorian renewable generation	2,257 MW, representing 30% of Victorian generation and consisting of: • 1,083 MW of wind • 190 MW of solar • 985 MW of hydro	795 MW, representing 24% of Victorian generation and consisting of: • 278 MW of wind • 516 MW of solar • 0 MW of hydro	1,218 MW, representing 28% of Victorian generation and consisting of: • 1,218 MW of wind • 0 MW of solar • 0 MW of hydro
Victorian synchronous generation	6,253 MW, representing 83% of Victorian generation and consisting of: • 4,294 MW of brown coal • 974 MW of gas • 985 MW of hydro	2,532 MW, representing 76% of Victorian generation and consisting of: • 2,434 MW of brown coal • 98 MW of gas 0 MW of hydro	3,060 MW, representing 71% of Victorian generation and consisting of: • 3,060 MW of brown coal • 0 MW of gas • 0 MW of hydro
Temperature at Melbourne Airport	30.3°C	20.8°C	14.3°C

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

[47] For the maximum demand snapshot ratings and loadings, see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

Maximum demand

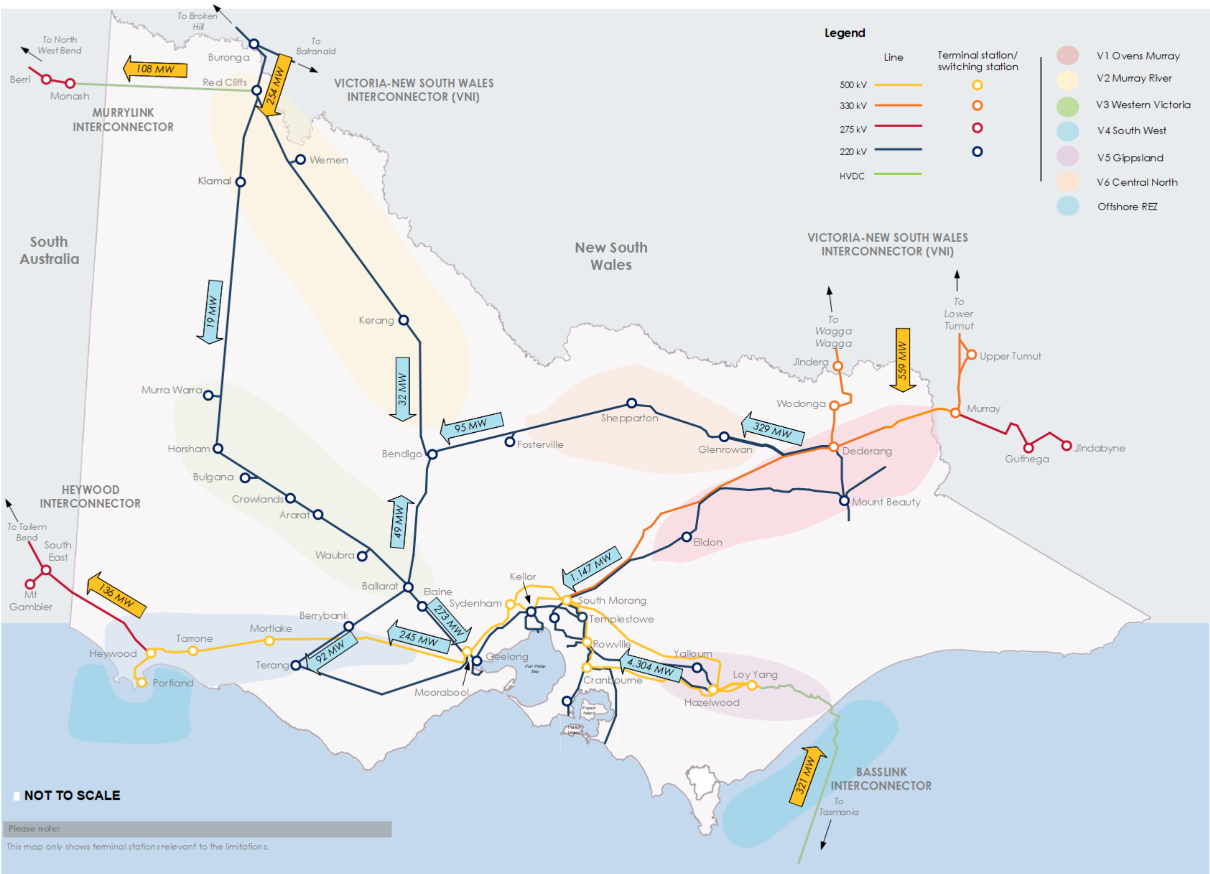
The maximum demand snapshot captures conditions when many network elements experience their maximum loading for the year. It is based on power system characteristics observed at 18:00 on 27 January 2022.

At the time of maximum demand, both southward flows into Victoria across VNI and westward flows across the Murraylink and Heywood interconnectors from Victoria to South Australia were at their binding limit. On this day, there were damaging winds forecast in South Australia and Victoria which caused a 250 MW limit to be invoked on transfers across the Heywood interconnector from Victoria into South Australia. No intra-regional constraints were binding in Victoria at the time of maximum demand.

At the time of maximum demand, all DSN elements were loaded below their n and n-1 limit. The DSN element with highest n loading was the Rowville A1 transformer at 69% of its continuous rating. The DSN elements with highest n-1 loading were the Springvale to Heatherton No. 1 and No. 2 lines loaded at 72% of their emergency rating for loss of the parallel line. 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[48].

Figure 16 shows the direction and magnitude of power flows through significant DSN corridors during maximum demand, with Melbourne's 6.1 GW load being supplied primarily from the Eastern and Northern corridors.

Figure 16 Map of power flows along significant corridors during maximum demand (18:00 on 27/1/2022)



[48] For the maximum demand snapshot ratings and loadings, see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

Daytime minimum demand

The 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 2.3.1).

During low demand in Victoria, operators have historically been required to take action to manage high voltages (see Section 2.5.3). At the time of minimum demand of 2,333 MW, the Hazelwood to South Morang No. 2 500 kV line had been switched out, and an NMAS contract activated to manage high voltages.

A heat map of post-contingent voltages across Victorian 500 kV terminal stations for a critical contingency is shown in Figure 17. Voltages are highest in and around the metropolitan load centres where the electrical distance from major generators is greatest. 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.

Additional storage to meet the Victorian Energy Storage Target (see Section 1.1.1), if incentivised appropriately, will assist by providing network support services in managing high voltages and other challenges during low demand periods.

Figure 17 Heat map of post-contingent voltages at 500 kV terminal stations for loss of a Loy Yang unit during minimum demand

The snapshot is based on power system characteristics observed at 1pm on 28 November 2021. At this time:

- VNI was exporting at its limit, which was set by thermal constraints during an outage of the Dederang to Wodonga 330 kV line.
- System strength constraints associated with this outage (see Section 2.5.1) were binding, limiting generators in the V2 Murray REZ.
- Basslink was also exporting towards Tasmania at its limit, set by system normal frequency control ancillary services (FCAS) constraints.

Night-time minimum demand

The night-time minimum demand snapshot contrasts the different network conditions which occur during the lowest operational demand occurring during night hours when demand was historically lowest against the lower annual minimum demand which typically occurs during the daytime.

The lowest night-time operational demand in 2021-22 was 3,485 MW, 1,150 MW higher than the annual minimum demand. At this level of demand, no operational intervention was required to manage high voltages.

A heat map of post-contingent voltages across Victorian 500 kV terminal stations for a critical contingency is shown in Figure 18. The post-contingent voltages across the 500 kV network are lower than or equal to those of the annual minimum demand snapshot, however the voltage at Keilor remains almost at its limit.

Similar to daytime minimum demand, additional storage to meet the Victorian Energy Storage Target will assist.

Figure 18 Heat map of post-contingent voltages at 500 kV terminal stations for loss of a Loy Yang unit during night-time minimum demand

The snapshot is based on power system characteristics observed at 04:00 on 26 December 2021. At this time:

- Basslink and VNI were both exporting at their limit (similar to the annual minimum demand snapshot). Basslink's limit was determined by system normal FCAS constraints, while VNI's limit was determined by system normal voltage collapse constraints.
- Murraylink was also importing at its limit, determined by system normal voltage collapse constraints.

In contrast to the annual minimum demand snapshot, the night-time minimum demand snapshot has a higher proportion of wind generation, and lower proportion of solar generation due to the time of day.

2.7.2 High wind generation

Wind generation in Victoria is primarily located in the V3 Western Victoria and V4 South West Vic REZs. Typically wind generation from the two REZs are coincidental due to geographical proximity. Maximum wind generation in Victoria occurred at 23:30 on 14/6/2022.

Table 12 Snapshot summary of operating conditions: maximum wind generation in Victoria.

Characteristic	Maximum wind
Date and time	14/06/2022 23:30
Victorian operational demand	5,747 MW
Distributed PV	0 MW
Net power flow into Victoria via interconnection*	-787 MW • 823 MW to NSW • 35 MW from SA • 0 MW to TAS
Victorian renewable generation	2,898 MW, representing 45% of Victorian generation and consisting of: • 2,867 MW of wind • 0 MW of solar • 31 MW of hydro
Victorian synchronous generation	3,586 MW, representing 55% of Victorian generation and consisting of: • 3,556 MW of brown coal • 0 MW of gas • 31 MW of hydro
Temperature at Melbourne Airport	9.4°C

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

At the time of maximum wind, 1,605 MW (56%) of Victorian wind generation was supplied from V3 Western Victoria. No wind in V3 Western Victoria was curtailed during this period, however six thermal constraints managing the flow along the Ararat to Waubra, Waubra to Ballarat, and Ballarat to Bendigo lines were either binding or close to binding (<10%).

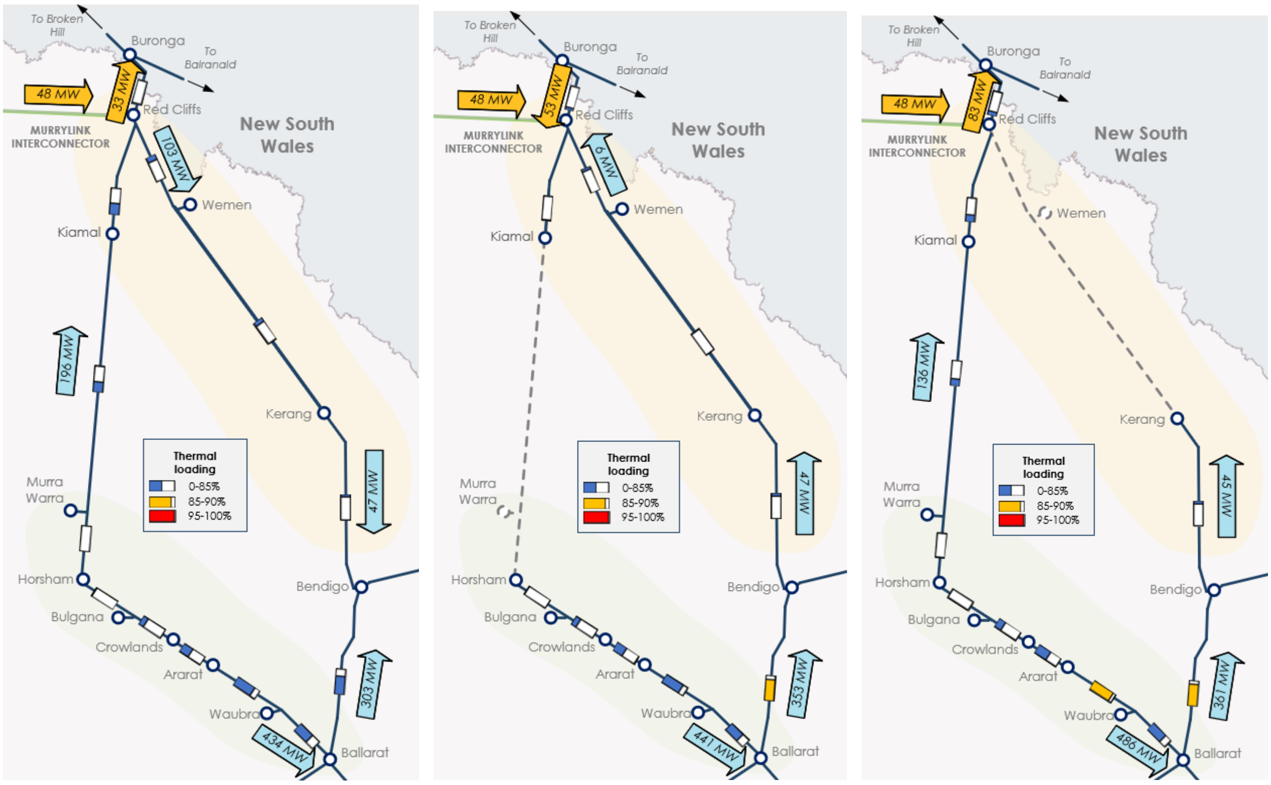
Figure 19 shows the pre-contingent (actual) loading and post contingent loading (expected)[49] and power flows across the 220 kV West Murray network for loss of the critical contingencies Horsham to Murra Warra to Kiamal and Red Cliffs to Wemen to Kiamal.

It shows that at the time of maximum wind generation, the Ararat to Waubra and Ballarat to Bendigo lines were approaching their post-contingent thermal limits. This snapshot occurred close to midnight when the thermal ratings of these critical lines were high due to low temperatures (9.4°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. If committed, the Western Renewables Link (see Section 3.4.3) will reduce instances when generation is limited by the Ararat to Waubra to Ballarat 220 kV line, while VNI West (see Section 3.4.4) will reduce instances when generation is limited by the Ballarat to Bendigo 220 kV line in Western Victoria.

At the time of maximum wind, 1,266 MW (44%) of Victorian wind generation was supplied from V4 South West Vic REZ. Wind generation in the V4 South West Vic 500 kV network operated without impact from network constraints at this point in time, but as new generation continues to connect in this area, both thermal and voltage collapse limitations are beginning to restrict local generation (see Section A2.5).

[49] Based on power system modelling.

Figure 19 West Murray flows and loading: pre-contingent (left), post-contingent for loss of Horsham – Murra Warra – Kiamal (middle), and post-contingent for loss of Red Cliffs – Women – Kerang (right)



The critical contingency for these emerging limitations is loss of either the Haunted Gully to Moorabool or Mortlake to Moorabool 500 kV lines together with both APD potlines, causing low voltages at Heywood and APD terminal stations, and pushing the loading of parallel lines to their thermal limit.

Figure 20 below shows the pre-contingent (actual) and post-contingent (expected) flows and loadings in the V4 South West Vic 500 kV network for loss of Haunted Gully to Moorabool line and both APD potlines.

Since September 2021, the Heywood to Tarrone and Heywood to Mortlake 500 kV lines have been run at significantly reduced ratings due to protection limitations preventing the lines from running at their full thermal capacity. Consequently, the post-contingent loading on these lines is higher than any others in the V4 South West Vic 500 kV network.

The RDP Stage 1 Mortlake turn-in project (see Section 3.4.5) would help distribute the power generated by V4 South West Vic wind farms across the 500 kV network, and in this instance would reduce the loading on the Heywood to Tarrone and Heywood to Mortlake lines with lowest thermal rating. Preparatory activities on the South West Vic REZ expansion project, identified as a future ISP project, will further assess how the 500 kV South West Vic network may best be augmented to manage flows.

Figure 20 500 kV flows and loadings V4 South West Victoria pre-contingent (above) and post-contingent for loss of Haunted Gully to Moorabool and both APD potlines (below)

Note: The geographic distance between parallel lines in Figure 20 has been exaggerated to demonstrate which terminal stations are connected to each line.

2.7.3 High solar generation

Solar generation in Victoria is primarily located in the V2 Murray River REZ (624 MW) and V6 Central North REZ (295 MW). Solar generation connected in V2 Murray River REZ currently experiences notable thermal and voltage network constraints on the Red Cliffs, Wemen and Kerang 220 kV line, while solar generation connected in V6 Central North can currently be accommodated by the existing network without significant constraint. This solar generation case study focuses on V2 Murray River solar generation. Maximum V2 Murray River solar generation occurred at 13:00 on 26/10/2021.

Table 13 Snapshot summary of operating conditions: maximum solar generation in V2 REZ

Characteristic	Maximum V2 solar
Date and time	26/10/2021 13:00
Victorian operational demand	3,255 MW
Distributed PV	2,107 MW
Net power flow into Victoria via interconnection*	-206 MW • 701 MW to NSW • 261 MW from SA • 234 MW from TAS

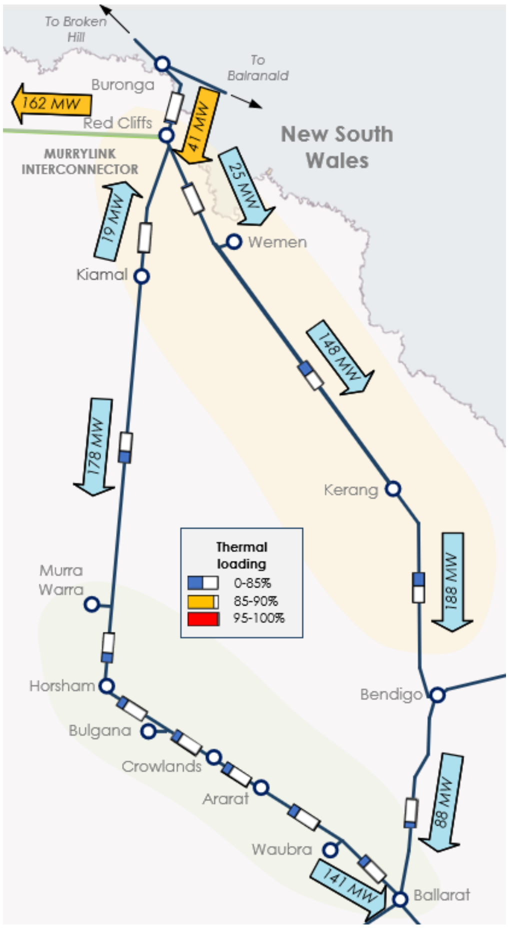
Characteristic	Maximum V2 solar
Victorian renewable generation	1,016 MW, representing 26% of Victorian generation and consisting of: • 15 MW of wind • 853 MW of solar • 148 MW of hydro
Victorian synchronous generation	3,005 MW, representing 78% of Victorian generation and consisting of: • 2,857 MW of brown coal • 0 MW of gas • 148 MW of hydro
Temperature at Melbourne Airport	18°C

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

At the time, 572 MW of solar in V2 Murray was generating, and 7 MW of solar in the Wemen 66kV network was curtailed to avoid pre-contingent overload of the Wemen B1 and B2 220/66kV transformers in reverse flow. This loading is managed by the constraint V>V_NIL_17 which was binding at the time. The constraint V^^V_NIL_KGTS, managing flow from Wemen to Kerang for loss of Crowlands to Bulgana to Horsham or Horsham to Murra Warra to Kiamal to avoid voltage collapse around Kerang, was also binding during maximum V2 solar generation. No other Victorian intra-regional constraints were binding or close to binding (<10%).

Figure 21 shows the loading and power flows across the 220 kV West Murray network during the maximum solar snapshot.

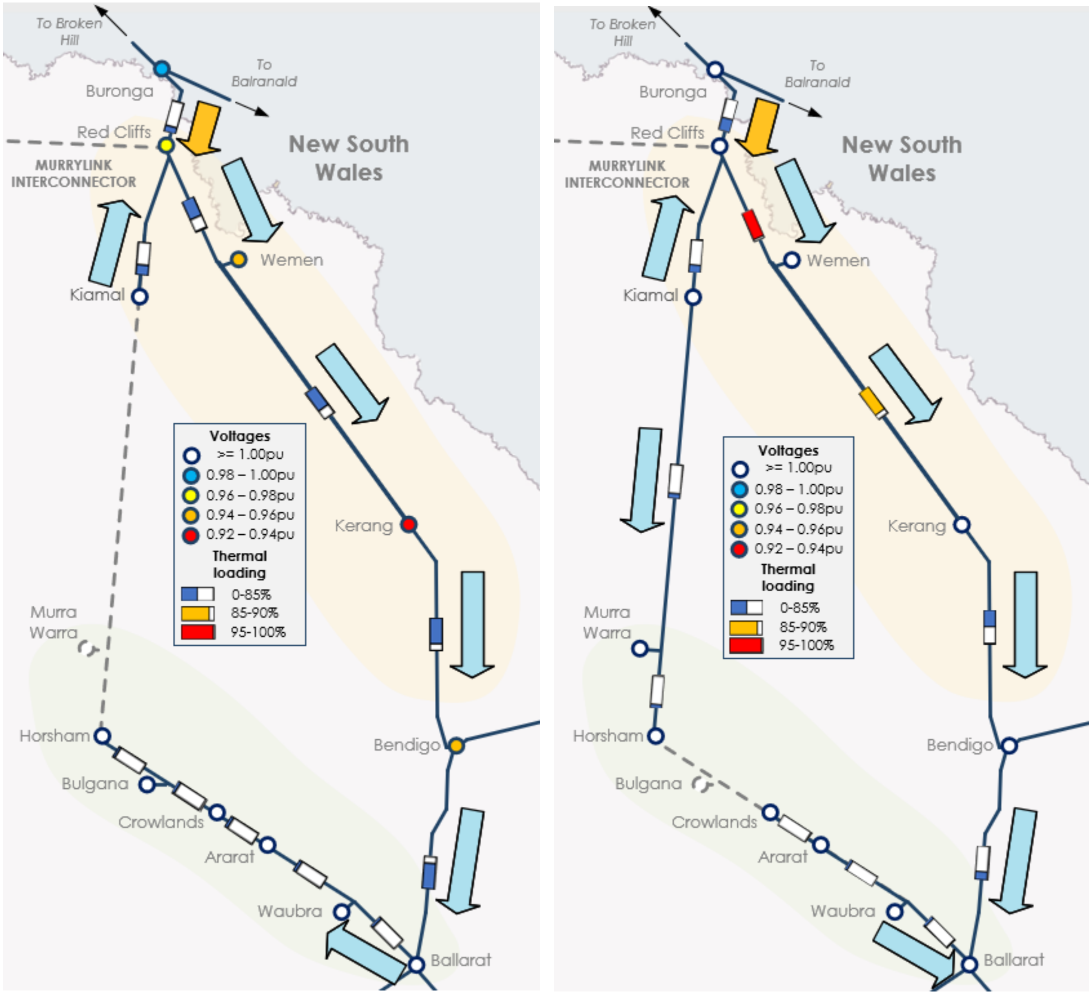
Figure 21 West Murray flows and loading during maximum V2 Murray River solar generation



The primary transmission limit requiring constraints in V2 Murray River is the Red Cliffs to Wemen to Kerang 220 kV line. Both thermal and voltage collapse constraints managing the flow along this line bind frequently (see Section 2.6), with voltage collapse constraints typically being the first to bind except on hot days when thermal ratings are low.

Figure 22 below shows examples of post-contingent conditions when voltage and thermal limits were binding in V2 Murray River during high solar generation in 2021-22. These are based on historical snapshots from 2021-22.

Figure 22 Example snapshots of post-contingent low voltages (left) and thermal overloads (right) during high V2 Murray River solar generating periods



Temperatures were much higher in the right snapshot (36°C at Melbourne airport) than the left snapshot, resulting in lower ratings and causing thermal constraints to bind before voltage constraints, while on the left, low temperatures (9.6°C at Melbourne airport) lead to higher thermal limits, at which point voltage constraints prevailed instead. For both thermal and voltage limitations, the Murraylink Very Fast Runback Scheme increases the post-contingent flow from Wemen to Kerang, exacerbating these limitations. Following updates to the Murraylink Very Fast Runback scheme, scheduled to be implemented in Q4 2022 (see Section 3.4.1), Murraylink is no longer run back for loss of critical lines during high V2 solar generation.

2.7.4 High exports

VNI typically exports more often than it imports, and exports are currently most constrained by voltage collapse constraints (see Section 2.4).

The high export snapshot shows network operating conditions when VNI exports were highest.

Table 14 Victoria export snapshot of operating conditions

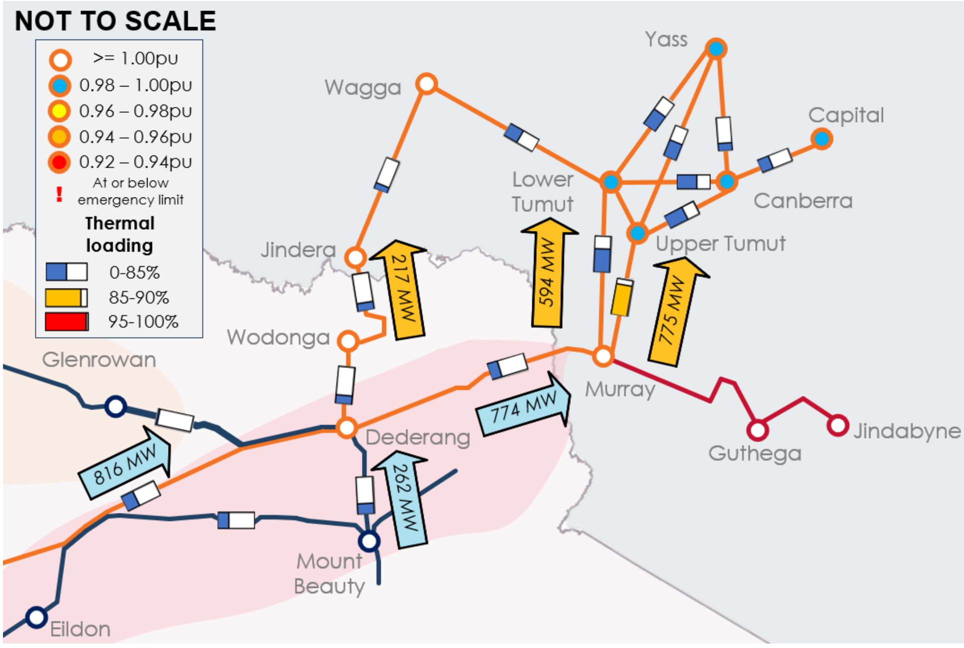
Characteristic	High exports
Date and time	15/06/2022 06:30
Victorian operational demand	5,508 MW
Distributed PV	0 MW
Net power flow into (or out of) Victoria via interconnection*	1,378 MW • 1,693 MW to NSW • 315 MW from SA • 0 MW to TAS
Victorian renewable generation	3,475 MW, representing 49% of Victorian generation and consisting of: • 2,781 MW of wind • 2 MW of solar • 692 MW of hydro
Victorian synchronous generation	4,209 MW, representing 59% of Victorian generation and consisting of: • 3,349 MW of brown coal • 168 MW of gas • 692 MW of hydro
Temperature at Melbourne Airport	9.3°C

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

The VNI maximum exports snapshot assesses the network conditions at 06:30 on 15 June 2022, when VNI was dispatched at 1,567 MW.

At the time, the South Morang series capacitors were out of service, which decreases the level of exports that can be achieved before voltage collapse occurs. Figure 23 below shows the flows, loading and voltages across the VNI Eastern corridor during the maximum export snapshot.

Figure 23 Maximum export flows, loading, and voltages in the VNI Eastern corridor



3 Network developments

This chapter provides an update on supply changes, as well as the network investment activities and investigations that have progressed since the 2021 VAPR. The network development will facilitate the integration of additional renewable generation while supporting Victorian power system security and reliability.

Key insights of Victorian network development

- Victoria's rapid energy transition is being driven by large-scale renewable energy generation, so far mostly connected in the west of the state, and the strong uptake of distributed generation by consumers.
- The total installed generation capacity in Victoria, as at July 2022, is 18.6 GW[50]:
  - 7.7 GW of large scale renewable generation (wind, solar, storage and hydro).
  - 7.4 GW of large scale conventional generation (coal and gas).
  - Approximately 3.5 GW[51] of distributed energy resources (DER) including 3.5 GW of distributed PV and 42 MW of distributed storage.
- Since the 2021 VAPR, approximately 2.4 GW of new large-scale renewable projects have connected in Victoria. Another 267 MW are committed to connect, and approximately 37.5 GW of additional wind (onshore and offshore), large-scale solar, and battery storage projects are proposed to connect.
- To meet the forecast future needs of the system, AVP is progressing a suite of projects across the state through its *Transmission Development Plan for Victoria*, which is updated annually. This plan aligns with the ISP and is designed to deliver security and reliability objectives in the context of Victorian Government policy and regulatory settings. The investments in the plan help to 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.
- 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.

3.1 Supply changes since the 2021 VAPR

This section reviews completed and committed changes to Victoria's fleet of generation and storage projects since publication of the 2021 VAPR. The scale and type of these projects highlight the changing nature of the Victorian power system, and are the key drivers for network projects discussed later in this chapter. The changes also underpin the changes in DSN limitations, discussed in Chapter 4. Information on existing, committed, and potential generation projects is from AEMO's generation information page[49].

[50] See AEMO, Generation Information webpage, August 2022, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[51] 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 31 July 2022.

Newly connected projects

Approximately 2.4 GW of large (individually greater than 20 MW) generator projects completed commissioning since the 2021 VAPR:

- Stockyard Hill Wind Farm stage 1 and stage 2 (532 MW) connected at Haunted Gully Terminal Station.
- Victorian Big Battery (300 MW) connected at Moorabool Terminal Station. The battery also provides System Integrity Performance Scheme (SIPS) service (see section 3.4.1).
- Dundonnell Wind Farm (336 MW) connected at Mortlake Power Station.
- Moorabool Wind Farm (312 MW) connected at Elaine Terminal Station.
- Murra Warra Wind Farm – Stage 2 (209 MW) connected at Murra Warra Terminal Station.
- Kiamal Solar Farm – Stage 1 (200 MW) connected at Kiamal Terminal Station.
- Yendon Wind Farm (144 MW) connected at Ballarat Terminal Station via Powercor distribution network.
- Bulgana Green Power Hub including Bulgana Wind farm – Stage 2 (104 MW) and Battery Energy Storage System (BESS, 20 MW) connected at Bulgana Terminal Station.
- Winton Solar Farm (85 MW) connected at Glenrowan Terminal Station via AusNet distribution network.
- Yatpool Solar Farm (94 MW) connected at Red Cliffs Terminal Station via Powercor distribution network.
- Cohuna Solar Farm (27 MW) connected at Kerang Terminal Station via Powercor distribution network.

One generator upgrade has been completed since the 2021 VAPR, at Loy Yang A, allowing an additional 15 MW of generation capacity.

Newly committed projects

Since the 2021 VAPR, the following generation projects (individually greater than 20 MW) have become committed, meaning they 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:

- Mortlake South Wind Farm (157.5 MW) – DSN connected at Terang Terminal Station.
- Berrybank Wind Farm Stage 2 (109.2 MW) – DSN connected at Berrybank Terminal Station.

Retirement projects (announced)

No new retirements in the next 10 years were announced since the 2021 VAPR.

New terminal station developments to support connections

There has been no new terminal station developed since the publication of the 2021 VAPR

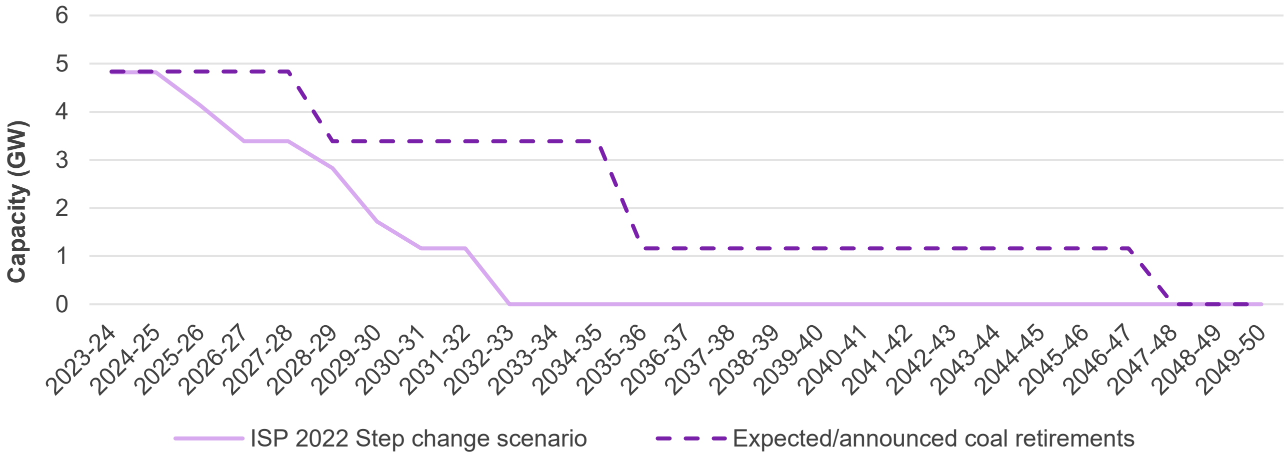
3.2 Supply changes forecast in Victoria

In the 2022 ISP, the *Step Change* scenario is considered the most likely scenario. This scenario represents a future with a rapid, consumer-led transformation of the energy sector and a coordinated economy-wide approach to efficiently lower emissions. Technology improvements in capability and cost provide a backdrop to faster net zero emission reduction ambitions, with greater adoption of energy efficiency measures and co-ordinated DER.

Rapid emission reduction is a key assumption as part of the ISP *Step Change scenario* considering the application of economy-wide carbon budgets to limit global temperature rise to well below 2°C compared to pre-industrial levels. With a carbon budget applying to all sectors in *Step Change*, electricity emissions are identified as efficient early savings, and in particular higher emitting Victorian brown coal generators are assumed to retire sooner than the black coal fleet in New South Wales and Queensland[52].

Figure 24 shows projected Victorian coal retirements in the 2022 ISP *Step Change* scenario compared to announced/expected closure years reported by participants. The announced/expected retirement of Yallourn Power Station is in 2028, Loy Yang A in 2035, and Loy Yang B in 2047[53].

Figure 24 Victorian coal retirement outlook in 2022 ISP *Step Change* scenario and compared to expected/announced retirement dates



Overall electricity demand is also projected to increase state-wide as other sectors electrify to reduce their own carbon emissions. Therefore, to replace retiring coal generation and supply the increasing demand, the 2022 ISP optimal development path projects a large number of additional renewable generation and storage projects, which are free of carbon emissions and sustainable (see Figure 25)[54].

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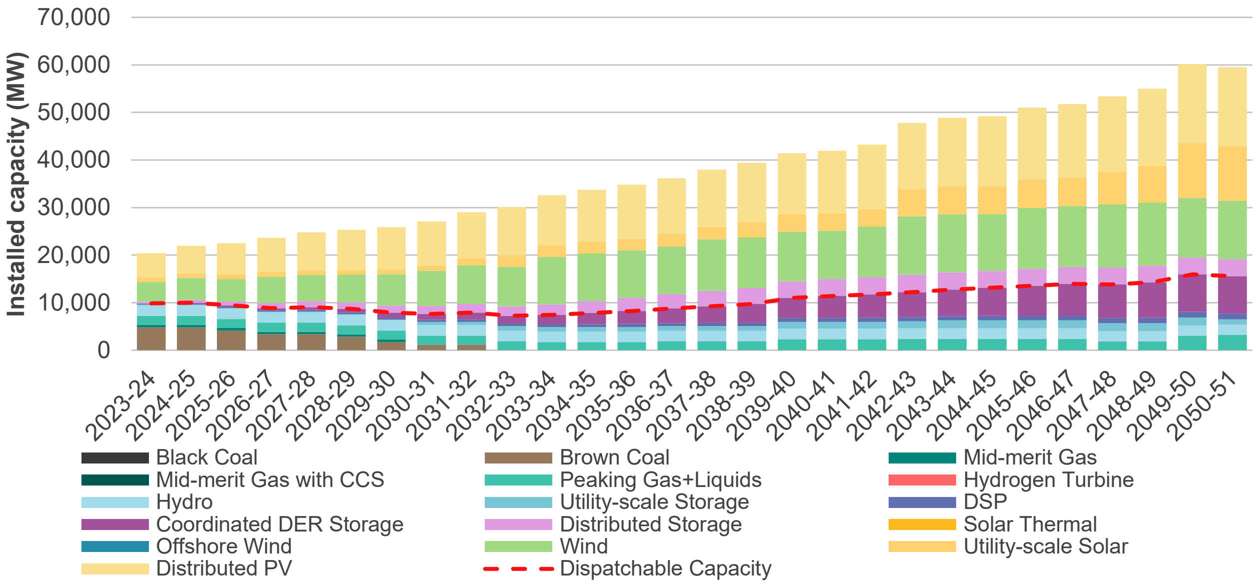
[52] See https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en.

[53] See AEMO, Generation Information webpage, Generating Unit Expected Closure Year October 2022 https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

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

Figure 25 Victorian installed capacity outlook in the 2022 ISP *Step Change* scenario



The 2022 ESOO continues to forecast large reliability risks in Victoria following the closure of Yallourn Power Station in 2028 in all scenarios. The *Anticipated and Actionable* ESOO sensitivity reveals that after anticipated generation and storage projects (including 350 MW Wooreen Battery) and anticipated and actionable ISP transmission projects are considered, including WRL, Marinus Link and VNI West, the forecast reliability outlook in Victoria improves, but remains above the reliability standard from 2028-29 onwards. Additional generation developments not yet considered committed or anticipated are required to utilise the additional transfer capacity from neighbouring regions unlocked by actionable ISP projects and bring forecast USE below the reliability standard.

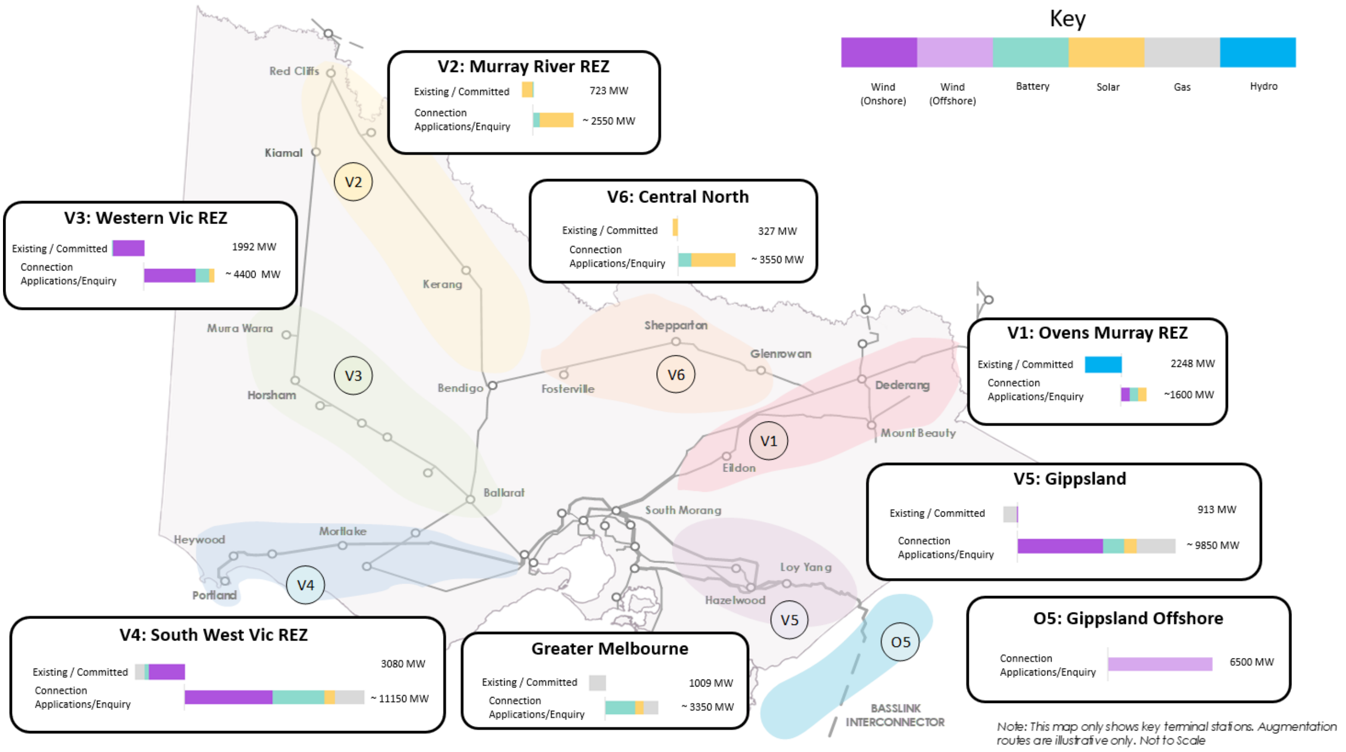
The Victorian Government, through its RDP Stage 1 projects, offshore wind targets, and other initiatives highlighted in Section 1.1.1, is supporting development of the storage and VRE that is needed for the transition.

3.2.1 Victorian connections pipeline

Investment interest in Victoria remains high, with a number of large-scale renewable generator and battery connections projects in the connections pipeline, as shown in Figure 26[55].

[55] See AEMO, Generation Information webpage, August 2022, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Figure 26 Summary of existing capacity and connections pipeline in Victoria



3.3 Renewable energy investment

Victoria continues to attract strong interest in new renewable generation projects, driving the rapidly changing operational landscape. As Figure 27 shows:

- The total installed generation capacity (large-scale and distributed) in Victoria has increased to 18.6 GW[56].
- Installed renewable generation capacity is 11.2 GW (61% of total large-scale and distributed generation) including:
  - 5.4 GW of large-scale wind, solar generation, and battery storage.
  - 2.25 GW of hydro generation.
  - Approximately 3.5 GW[57] of distributed energy resources (DER) including 3.5 GW of distributed PV and 42 MW of distributed storage.

Since publication of the 2021 VAPR, approximately 2.4 GW of large-scale renewable projects have connected in Victorian network. The largest increase was in onshore wind generation capacity, which approximately increased from 2.5 GW to 4.0 GW. There is a further 267 MW of wind capacity committed to connect in Victoria. A further 37.5 GW[58] of additional wind, solar and storage projects have proposed to be connected.

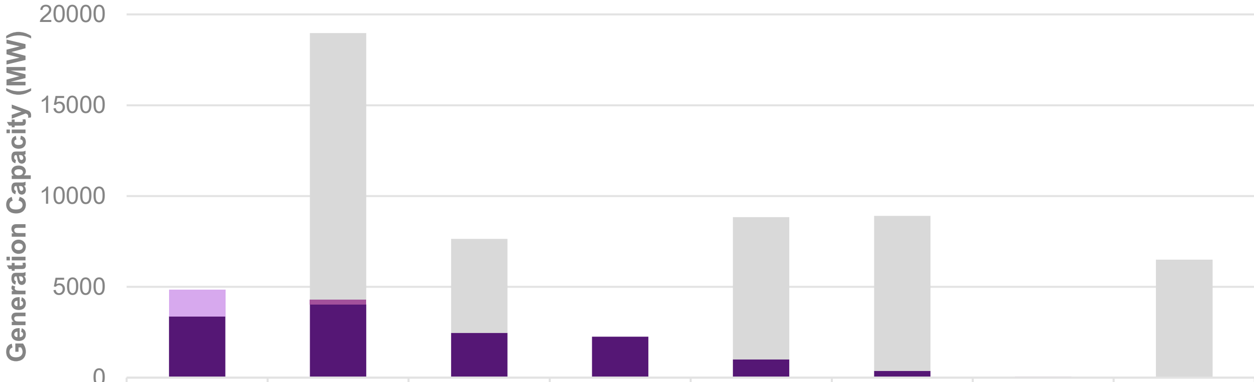
[56] See AEMO, Generation information, August 2022, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[57] 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 31 July 2022.

[58] See AEMO, Generation Information webpage, August 2022, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

The Victorian Offshore Wind Policy Directions Paper[59] outlines Victoria's vision for offshore wind, paving the way to host the first offshore wind farms in Australia. The plan includes procuring an initial offshore wind tranche of at least 2 GW, aiming for first power to come progressively online from 2028 following a competitive process, with targets of 4 GW of offshore wind capacity by 2035 and 9 GW by 2040. Ideally, the transmission infrastructure needed to connect this amount of offshore wind capacity in a REZ will be co-ordinated in an efficient way that minimises social and environmental impacts and consumer costs. Further information on the approach to developing the transmission needed to support this offshore wind is provided in the Victorian Government's Offshore Wind Implementation Statement 1.

Figure 27 Currently existing, committed and proposed large-scale generation capacity in Victoria



	Coal	Wind-Onshore	Gas	Hydro	Solar	Battery Storage	Biomass	Wind-Offshore
Proposed projects		14668	5174		7827	8536		6500
Committed projects		267						
Announced Retirement	1450							
Existing [less Retirement]	3385	4029	2467	2248	1005	375	58	

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.

The Victorian Government's VRET scheme, which seeks to deliver 40% renewable energy generation by 2025 and 50% by 2030[60], continues to attract investors. The VRET2 auction[61], targeting 623 MW of new renewable generation capacity and up to 365 MW and 600 MWh of new battery energy storage was announced in October 2022, will further encourage generation to be connected in the Victorian DSN.

Much of the proposed VRE is expected to be built in the Victorian REZs, which seek to coordinate network and renewable investment. Through the Victorian Transmission Investment Framework, the Victorian Government is aiming to foster a more holistic approach to REZ development, supporting local employment, economic opportunity, and community participation. Victorian REZs are aiming to improve grid reliability and security, whilst minimising community, environmental and aesthetic impacts. Other benefits to the development of REZs ensure adherence to relevant design standards and regulatory requirements, and offer flexibility and scalability to build power system resilience and address the future needs of the power system.

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

[60] See https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

[61] See https://www.energy.vic.gov.au/renewable-energy/vret2.

3.3.1 Geographic shifts in generation

As Victoria decarbonises its electricity grid, the geographic location of supply has shifted from the east of the state, where large brown coal generators in the Latrobe Valley exists towards the west, where the wind and solar resources are abundant. Consequently, the network to the state's west is being utilised above and beyond it's intended design, which has constrained renewable generators in the short-term, and introduced the need for major transmission augmentations such as Western Renewables Link in the medium to long-term.

Figure 28 shows the duration curves for 500 kV flow from the Latrobe Valley in the state's east into Melbourne. It shows that each year following the retirement of Hazelwood Power Station in 2017, the flow along these lines has reduced, with greater periods of time spent at the lower end of range.

These flows are expected to continue to decrease further, particularly following the anticipated retirement of Yallourn Power Station in 2028. The 500 kV flow from the Latrobe Valley is dependent on future generation (size and location) in the Latrobe Valley and the operational configuration of the local DSN. Currently the Hazelwood Terminal Station can be configured in either radial mode or parallel mode, and one of the four Yallourn Power Station units, unit W1, can be connected to either the local 220 kV network or the 500 kV network between the Latrobe Valley and Melbourne via 220 kV to 500 kV transformation at Hazelwood Terminal Station. AEMO will review and change the operational configuration of the Latrobe Valley DSN, accounting for the expected retirement of Yallourn Power Station and new generation/BESS connections, to optimise the distribution of flows on the 500 kV and 220 kV lines between the Latrobe Valley and Melbourne and in turn address network limitations. Refer to Appendix A4 for more information about radial or parallel mode.

Figure 28 Duration curves Latrobe Valley to Melbourne 500 kV flow, 2017 to 2022

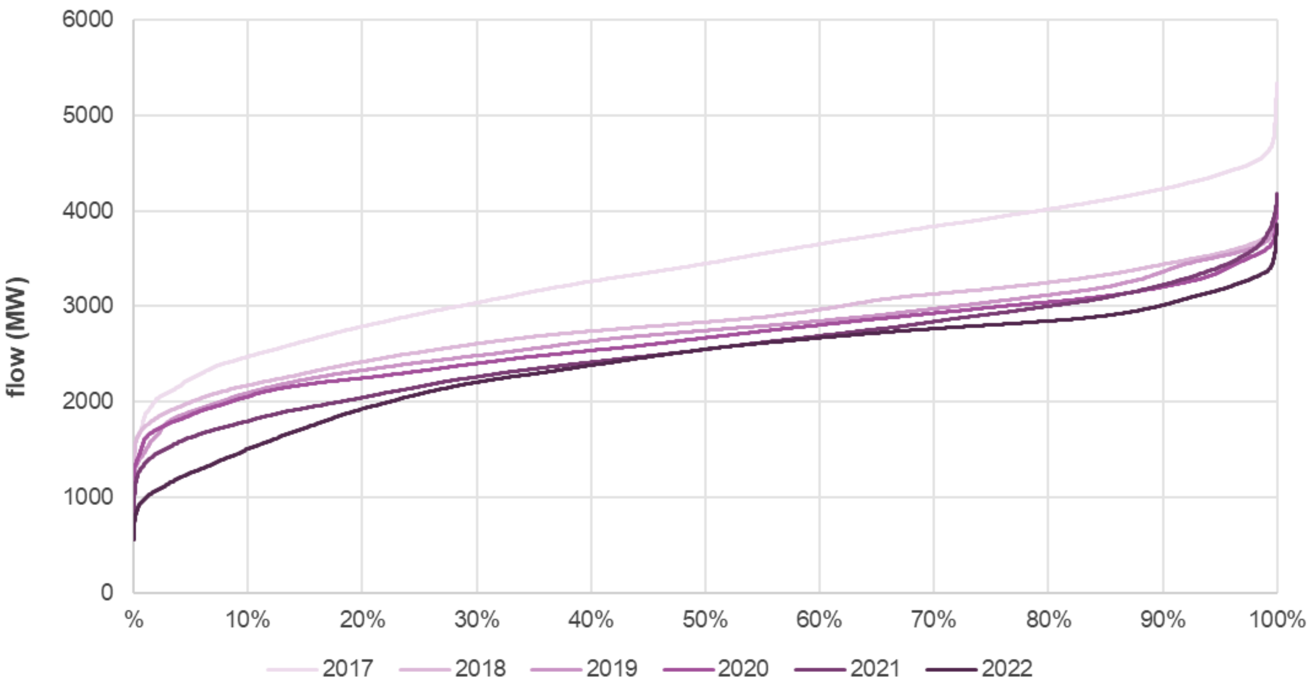
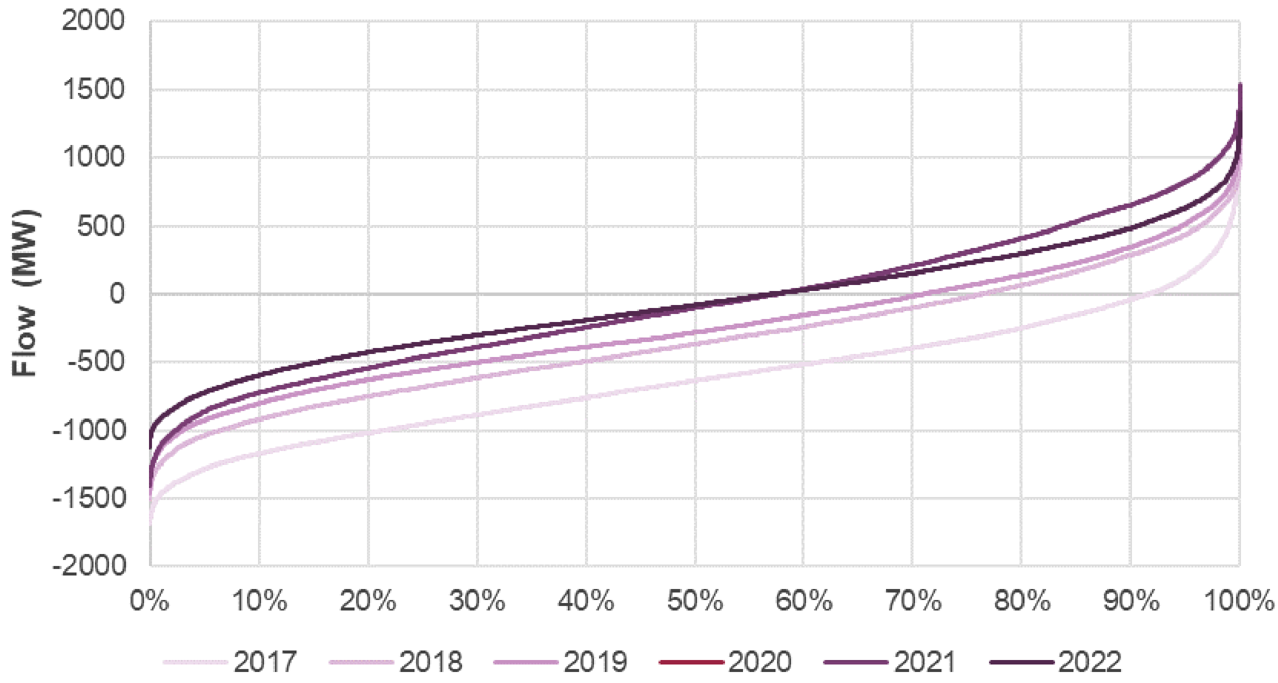


Figure 29 shows duration curves of generation from west and south west Victoria into the greater Melbourne and Geelong areas. In recent years, renewable generators have connected in western Victoria, increasing the flows into Melbourne from the western generation. This trend is expected to continue into the future and potentially present new generation driven limitations in western and south western Victoria. The anticipated Western Renewables Link project and the recently announced RDP Stage 1 projects will help relieve existing and expected limitations.

Figure 29 Duration curves flow from western and south western Victorian generation



3.4 Transmission Development Plan for Victoria

To address the emerging operational issues highlighted in Section 2.5 and Section 2.6, and to deliver a system capable of facilitating the supply changes identified in sections 3.2 and 3.3, AVP is progressing a suite of projects across the state through its *Transmission Development Plan for Victoria*, which is reviewed and updated each year as part of the VAPR.

The 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. It has been designed to efficiently deliver system security requirements, maintain supply reliability, and minimise overall costs to consumers in the context of Victorian Government policy and regulatory settings.

This section presents projects across the following categories:

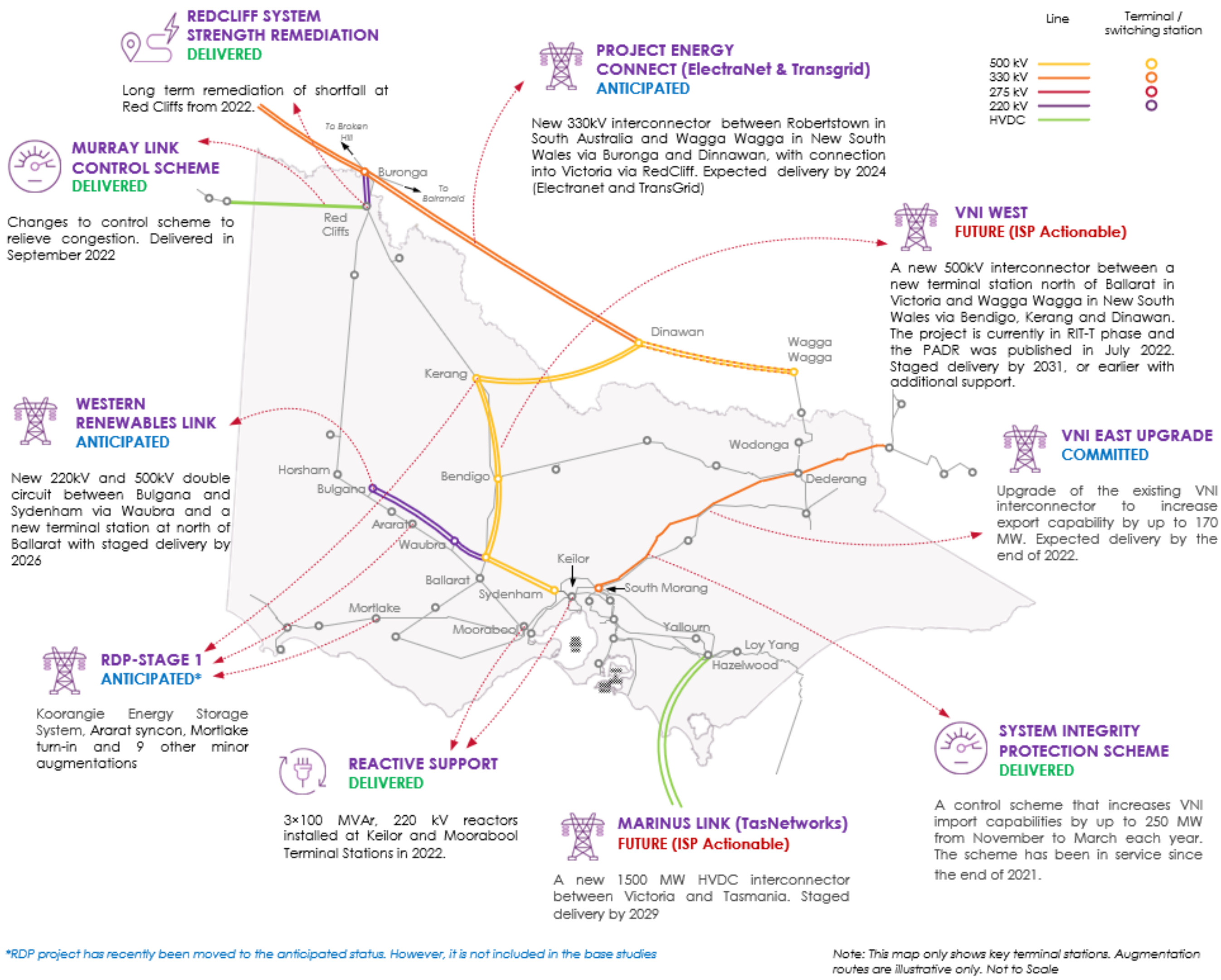
- **Delivered projects** – projects completed since the publication of 2021 VAPR.
- **Committed projects** – projects which meet all five commitment criteria in the ISP Methodology[62] (relating to site acquisition, components ordered, planning approvals, finance completion and set construction timing).
- **Anticipated projects** – projects which are in the process of meeting at least three out of the five commitment criteria in the ISP methodology.

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

- **Future projects** –mid- and long-term projects that are currently progressing through the regulatory process. These includes all actionable projects identified in the 2022 ISP under its optimal development path.

The project categorisation has changed from the previous VAPRs to align with the 2022 ISP. Figure 30 summarises AVP's 2022 *Transmission Development Plan for Victoria*. The rest of this chapter provides further details about each project.

Figure 30 Transmission development plan for Victoria and neighbouring TNSP projects



3.4.1 Delivered projects

The following committed projects reported in the 2021 VAPR have since been completed:

- **Victorian Reactive Power Support RIT-T** – all reactors as part of the preferred RIT-T option are now in service. Since the 2021 VAPR, the second 220 kV 100 MVAr reactor at Keilor Terminal Station was commissioned in December 2022. The two 220 kV 100 MVAr shunt reactors at Moorabool Terminal Station were commissioned in July and August 2022.

- **Red Cliffs System Strength Remediation** – since the 2021 VAPR, AVP has finalised the Invitation to Tender and has entered into system strength services contracts from three synchronous condenser in the West Murray area. The contract came into effect on 1 August 2022.
- **System Integrity Protection Scheme (SIPS)** – the SIPS scheme, delivered through VBB, was in service over the 2021-22 summer from 1 November 2021 to 31 March 2022. The scheme was designed to increase the pre-contingency import capabilities of the VNI by up to 250 MW between November to March each year, by rapidly discharging VBB following a critical contingency event to reduce loading on critical lines.
- **Murraylink Very Fast Runback (VFRB) scheme (Vic) Enhancement** – AVP is finalising changes to the operational criteria to the Murraylink VFRB scheme that would allow additional generation in the V2 and V3 REZs when Murraylink is exporting. These changes are based on the recommendation of the Victoria control scheme review as outlined in the 2020 VAPR.

Refer to Section 3.3 of the 2021 VAPR[63] for more information about the above projects.

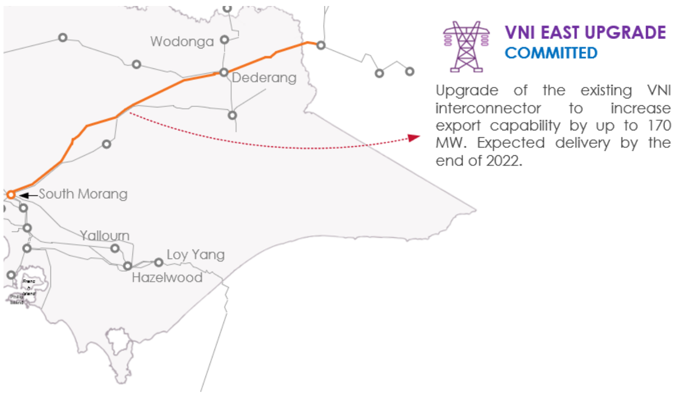
3.4.2 Committed projects

VNI East Upgrade

Power transfers from Victoria to New South Wales are currently restricted by thermal, voltage stability, and transient stability limitations (see Section 2.6). Resolving these limitations will allow more efficient sharing of resources between regions and improve supply adequacy following the Liddell Power Station retirement in 2022-23.

The VNI East Upgrade project consists of:

- Installation of a second 500/330 kV transformer at South Morang Terminal Station.
- Re-tensioning of the 330 kV South Morang – Dederang transmission lines, as well as associated works (including replacement of series capacitors), to allow operation at thermal rating.
- Installation of modular power flow controllers on the 330 kV Upper Tumut to Canberra and Upper Tumut to Yass lines to balance power flows. This work is being undertaken by TransGrid in New South Wales.



In February 2020, AVP and TransGrid completed a RIT-T[64] that assessed network and non-network options to address the transfer capacity of the existing VNI.

The project is non-contestable and is currently contracted to be delivered in October 2022. However AusNet, who is undertaking the works on the Victorian side, has indicted that an extension of time variation request will soon be issued to AVP requesting a delivery extension to February 2023.

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

[64] At https://www.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.

3.4.3 Anticipated projects

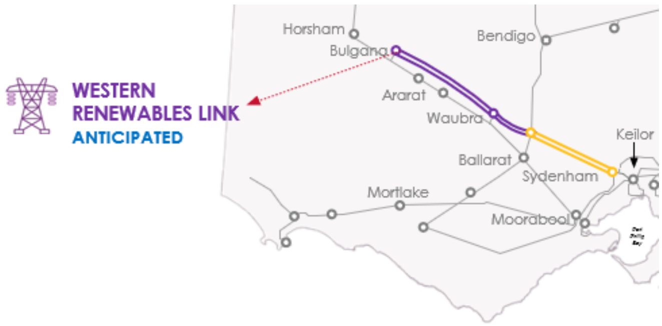
Western Renewables Link

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 Renewable Integration RIT-T) to unlock renewable energy resources, reduce network congestion, and improve utilisation of existing assets in western parts of Victoria[65]. 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.

The Western Renewables Link consists of:

- A new 500/220 kV terminal station north of Ballarat with two new 1,000 MVA 500/220 kV transformers.
- New 220 kV double circuit transmission lines from Bulgana Terminal Station to Waubra Terminal Station to the new terminal station north of Ballarat.
- New 500 kV double circuit transmission lines from Sydenham to a new terminal station north of Ballarat.



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[66]. This contestable project is currently estimated to be delivered by mid-2026.

Renewable Energy Zone Development Plan (RDP)

The Victorian Government's RDP Directions Paper[67] 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.

As presented in Section 3.4.3, AVP has now executed contracts for two of the three contestable services to strengthen the network, the Mortlake turn-in project and the nine non-contestable minor augmentations.

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

[66] See https://www.westvictnp.com.au/.

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

AVP is continuing to work collaboratively with the Victorian Government to progress procurement activities for the remaining South West REZ contestable services to strengthen the system.

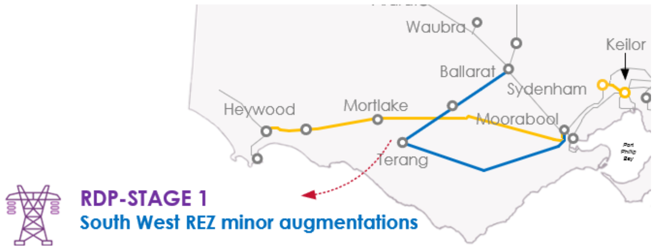
RDP Stage 1 – South West REZ minor augmentations

Harnessing additional generator connections in the South West REZ, and transferring that power to Melbourne's load centre, is currently limited due to various thermal limitations within the South West REZ.

Following an initial Ministerial Order in August 2021, directing AVP to progress procurement activities on behalf of the Victorian Government, in October 2022 AVP contracted for a range of minor augmentations to increase the generator hosting capacity in the South West REZ by the end of October 2025. The South West REZ minor augmentations consist of four separate projects designed to increase the South West REZ hosting capacity by an average of 81 MW.

The four South West REZ minor augmentations include:

- Establishing an automatic generator runback control scheme to manage thermal loading on the Ballarat – Berrybank – Terang – Moorabool 220 kV lines.
- Establishing temperature-dependant 5-minute and 15-minute dynamic line ratings, utilising AusNet Services' System Overload Control Scheme (SOCS), on the Moorabool to Heywood 500 kV line.
- Undertaking terminal station interplant asset replacements to increase the end-to-end thermal capacity of the Sydenham to Keilor 500 kV line.
- Undertaking terminal station interplant asset replacements to increase the end-to-end capacity thermal capacity of the Moorabool 500/220 kV transformers.



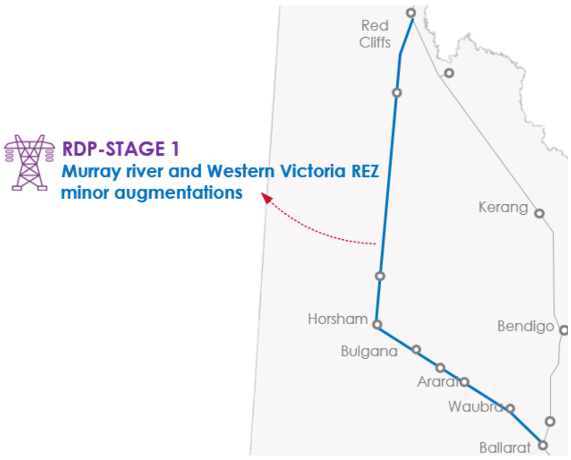
RDP Stage 1 – Murray River REZ and Western Victoria REZ minor augmentations

Harnessing additional generator connections in the Murray River and Western Victorian REZs is currently limited due to various thermal limitations within the REZs.

Following an initial Ministerial Order in August 2021, directing AVP to progress procurement activities on behalf of the Victorian Government, in October 2022 AVP contracted for a range of minor augmentations to increase the generator hosting capacity in the Murray River and Western Victoria REZs by the end of October 2025. These minor augmentations consist of three separate projects designed to increase the REZ hosting capacity by an average of 112 MW.

The three Murray River and Western Victoria REZ minor augmentations include:

- Establishing an automatic generator runback control scheme to manage thermal loading on the Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana 220 kV lines.
- Modifying the existing Murraylink Very Fast Runback (VFRB) control scheme to also operate for Murraylink import from South Australia to Victoria to manage thermal loading on the Red Cliffs – Kiamal – Murra Warra – Horsham – Bulgana 220 kV lines.
- Undertaking terminal station interplant asset replacements at Ballarat, Ararat, Waubra, Bulgana and Kiamal terminal stations to increase the end-to-end thermal capacity of the Ballarat – Waubra – Ararat – Crowlands – Bulgana – Horsham – Murra Warra – Kiamal 220 kV line.



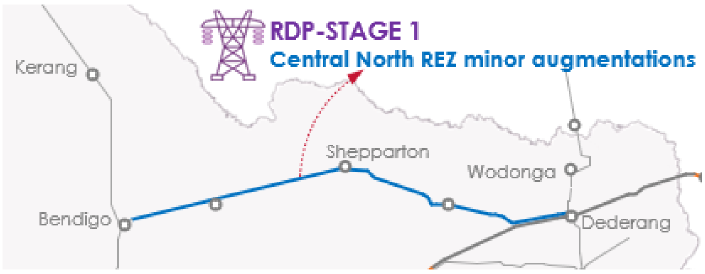
RDP Stage 1 – Central North REZ minor augmentations

Harnessing additional generator connections in the Central North REZ is currently limited due to various thermal limitations within the REZ.

Following an initial Ministerial Order in August 2021, directing AVP to progress procurement activities on behalf of the Victorian Government, in October 2022 AVP contracted for a range of minor augmentations to increase the generator hosting capacity in the Murray River REZ by the end of October 2025. The Central North REZ minor augmentations consist of two separate projects designed to increase the Central North REZ hosting capacity by an average of 12 MW.

The two Central North REZ minor augmentations include:

- Establishing an automatic generator runback control scheme to manage thermal loading on the Dederang – Glenrowan – Shepparton – Bendigo 220 kV lines.
- Installing a control scheme that automates the enablement of the additional cooling on the Dederang No.3 330/220 kV 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.



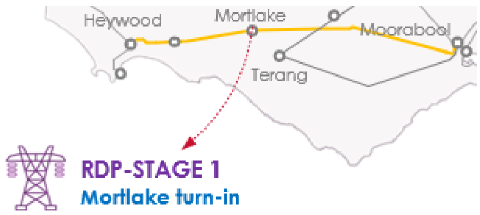
RDP Stage 1 – Mortlake turn-in

Harnessing additional generator connections in the South West REZ, particularly under high import from South Australia, is currently limited due to an existing limitation that secures the power system against voltage collapse for trip of the Moorabool – Mortlake 500 kV circuit.

Following an initial Ministerial Order in January 2022, directing AVP to progress procurement activities on behalf of the Victorian Government, in October 2022 AusNet Services was contracted by AVP to deliver the Mortlake turn-in project by the end of October 2025. Connecting this second circuit at Mortlake Power Station will allow a more balanced sharing of power between the two parallel circuits and will increase voltage stability in the South West REZ. The turn-in project is expected to allow up to 1,500 megawatts (MW) of additional generation output following its commissioning.

The Mortlake turn-in consists of:

- Installing four new 500 kV circuit breakers and associated equipment to fully populate one the existing 500 kV bays and establish a new additional 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.



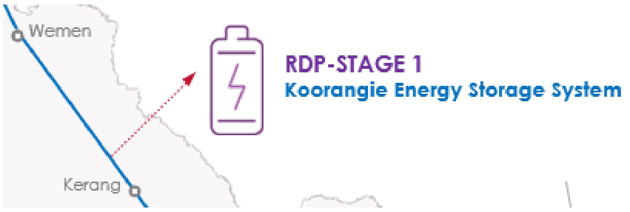
RDP Stage 1 – Koorangie Energy Storage System

Connecting new renewable generation in the Murray River REZ is currently limited by the lack of available system strength in the REZ.

Following an initial Ministerial Order in August 2021, directing AVP to progress procurement activities on behalf of the Victorian Government, in September 2022 Edify Energy was contracted by AVP to provide system strengthening services in the Murray River REZ. Edify Energy will provide these system strengthening services by establishing its proposed Koorangie Energy Storage System (KESS) utilising grid-forming inverters. The KESS is expected to allow the stable connection of up to 300 MW of additional generation by the end of March 2025.

The KESS consists of:

- 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.



RDP Stage 1 – Ararat synchronous condenser

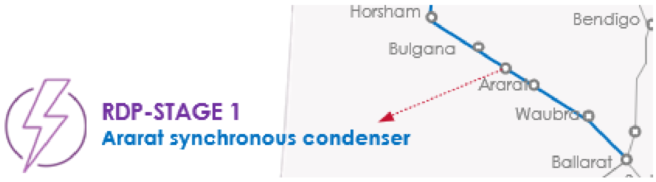
Connecting future IBR generation in the Western Victoria REZ will be limited by a lack of available system strength in the REZ.

Following an initial Ministerial Order in August 2021, directing AVP to progress procurement activities on behalf of the Victorian Government, in October 2022 Australian Energy Operations (AEO) was contracted by AVP to provide system strengthening services in the Western Victoria REZ. AEO will provide these system strengthening services by establishing its Ararat synchronous condenser. The system strength services provided by the proposed Ararat synchronous condenser are expected to allow the stable connection of up to 600 MW of additional generation the end of September 2025.

In addition to the contracted system strengthening services, the synchronous condenser can provide dynamic voltage and reactive power control services currently provided by the Horsham Static Var Compensator (SVC), which is nearing the end of its serviceable life.

The Ararat synchronous condenser consists of:

- Installing a new 250 MVA synchronous condenser to the existing Ararat Terminal Station.



3.4.4 Future projects

VNI West via Kerang (Actionable ISP project)

The 2022 ISP identifies VNI West as an actionable ISP project to be progressed urgently[68]. The project forms part of the optimal development path in the 2022 ISP. The 2022 ISP describes VNI West as a single actionable ISP project, noting that staging of the project through use of feedback loops will protect consumers from risks of over- or under-investment:

- Stage 1 – to carry out early works immediately for completion as soon as possible.
- Stage 2 – to complete implementation of the project.

In July 2022, AVP and TransGrid jointly published the Project Assessment Draft Report (PADR), identifying VNI West via a new terminal station near Kerang as the proposed preferred option. This option would connect the

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

Western Renewables Link (WRL) with Project Energy Connect (at Dinawan). The project is estimated to cost $3.256 billion[69].

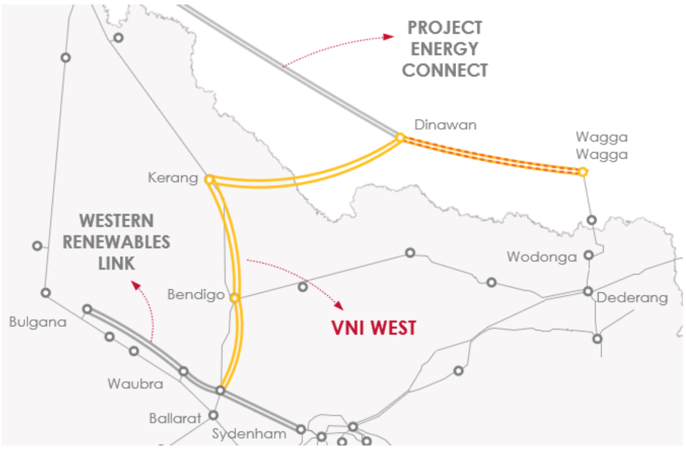
The results of the PADR assessment found that commencing early works as soon as possible and having VNI West operational by no later than July 2031 under the most likely (*Step Change*) scenario is projected to deliver approximately $687 million of scenario weighted net market benefits for consumers.

AVP and Transgrid are currently working towards publishing the VNI West Project Assessment Conclusions Report (PACR) early in 2023. Key considerations including technical, economic, social and environmental aspects will be considered once the route selection process commences. This will include work to assess the most appropriate connection point along the proposed Western Renewables Link route.

VNI West via Kerang, as proposed in the PADR, consists of:

- A double circuit overhead 500 kV transmission line from a new substation north of Ballarat (established under the Western Renewables link) to Dinawan terminal station (established under the Project Energy Connect)
- Upgrading of the 330 kV between Dinawan to Wagga Wagga (established under Project Energy Connect) to 500 kV.
- New 500 / 220kV terminal stations near Bendigo and Kerang.
- 220 kV connections from the existing terminal stations at Bendigo and Kerang to new terminal stations near Bendigo and 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.

Locations represented on the map are network schematics, have been provided for illustrative purposes only, and are subject to change.



3.5 Neighbouring TNSP projects

Project EnergyConnect – Anticipated

Project Energy Connect is an anticipated interconnector between South Australia and New South Wales, with connection to Victoria at Red Cliffs, and indicative 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 February 2019, ElectraNet completed its RIT-T assessment of this project[70].

Project Energy Connect broadly consists of:

- A new 330 kV double circuit interconnector from Robertstown in mid-north South Australia to Wagga Wagga in south-west New South Wales, via Buronga and Dinawan.
- A new 220 kV double circuit between Buronga in New South Wales and Red Cliffs in Victoria to replace the existing 220 kV single circuit line.

The South Australian component of the project was approved by the South Australian Government following assessment of the project's Environmental Impact Assessment in December 2021.

[69] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/VNI-West-Project-Assessment-Draft-Report.

[70] See https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf.

The New South Wales component is being undertaken in two sections:

- The western section, which will connect the New South Wales and South Australian transmission networks, received state and federal planning approval in late 2021 and construction activity has commenced at various locations.
- The eastern section, which connects the Buronga and Wagga Wagga substations, is currently progressing through the approvals process. A portion of the eastern 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.

Marinus Link – Actionable ISP project

Marinus Link is an anticipated 1,500 MW capacity electricity connection to further link Tasmania and Victoria. The 2022 ISP identifies this as a single actionable project, which needs to be progressed urgently[71]. The preferred option and optimal configuration in the PACR[72] is a 1,500 MW high voltage direct current (HVDC) interconnector, comprising two 750 MW HVDC stages, plus associated AC network upgrades for each stage including 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 also 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[73].

According to the 2022 ISP *Step Change* scenario, the expected delivery date for Stage 1 is 2029-30 and for Stage 2 is 2031-32. However, the PACR notes that the optimal timing of the project is dependent on the future development of the NEM. At this stage, the optimal timing for Stage 1 is as early as 2027 and no later than 2031, with Stage 2 required as early as 2029 and no later than 2034.

TasNetworks is proceeding with the early works required for Project Marinus to be able to achieve a Final Investment Decision (FID) expected in 2023-24, enabling commissioning of Stage 1 and Stage 2 at the earliest in 2027 and 2029 respectively.

HumeLink – Actionable ISP project

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[74], which links greater Sydney load centre with South Australia and Victoria through Project EnergyConnect (PEC), and the Snowy Mountains Hydroelectric Scheme[75]. AEMO's ISP indicates a staged approach to deliver HumeLink by 2026-27[76].

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

[72] See https://www.marinuslink.com.au/wp-content/uploads/2021/06/Project-Marinus-RIT-T-PACR.pdf.

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

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

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

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

4 Forecast limitations

This chapter explores potential new limitations that may reduce system performance, impact efficient asset utilisation, or result in additional network constraints.

Key forecast limitation insights

- Three new emerging limitations were identified in the full review of the Victorian power system this year. The first of these limitations is driven by increasing need for system strength support in Metropolitan Melbourne and the others are driven by increasing maximum and reducing minimum operational demand forecasts in the 2022 ESOO. AVP will commence feasibility assessment, including RIT-Ts if necessary, within 12 months to identify the preferred solutions and timings to relieve the following emerging limitations:
  - Minimum fault level requirements at Thomastown, Moorabool and Hazelwood fault level nodes.
  - High voltages in Metropolitan Melbourne and South West Victoria.
  - Metropolitan Melbourne area voltage stability.
- No new priority limitations were identified in this VAPR. Of the five priority limitations identified in the previous VAPR, four are now monitored limitations following recent announcements of the RDP Stage 1 projects, and one is a new emerging limitation.
- Seven developing limitations are currently under investigation. Of those, five were identified in past VAPRs (predominantly due to uptake of generator connections in regional areas, increasing maximum demand and decreasing minimum demand, and the announced retirement of Yallourn Power Station in 2028) and two are new developing limitations (which are driven by increased load in Metropolitan Melbourne, specifically at Deer Park terminal station)
- This year's VAPR provides an update on two key challenges faced by the Victorian DSN over the coming 10 years – rapidly declining minimum demand, and expected coal generation retirements.
  - Rapidly declining minimum demand:
    - The 2022 ESOO projects minimum demand will go negative in 2030-31 in the ESOO Central scenario, 2027-28 in the *Progressive Change* scenario, and 2026-27 in the *Slow Change* scenario, in the absence of coordinated storage[77]. Although the demand forecast is higher than the 2021 ESOO Central scenario, voltage control and system strength management during low demand periods in Victoria, under both system normal and prior outage conditions, are expected to still present challenges.
    - AVP has revised the immediate, short-term, and long-term limitations that would need to be addressed to manage voltages during low demand periods. A mix of operational measures and reactive power capability from new generation/battery connections and new grid-connected reactive plant were identified as potential solutions to the limitations.

[77] The Victorian Government's recent announcement on storage targets presents an opportunity for storage to charge/pumping during low demand periods, therefore delaying or even preventing impact of very low or negative demand on the DSN. See Section 1.1.1 for more information about this announcement.

- Announced and anticipated retirement of coal generation:
  - The 2022 ISP *Step Change* outlook forecasts retirement of synchronous generation earlier than announced dates. This capacity retirement, and the subsequent uptake of supply resources elsewhere in the DSN, will substantially impact the flow patterns of the network. This will exacerbate limitations where new generation is developed and current transmission capacity is limiting. Furthermore, the loss of reactive support from synchronous units coupled with increasing maximum demand and decreasing minimum demand, will exacerbate voltage and stability limitations.
  - The impact on DSN performance is sensitive to how the Latrobe Valley network would be configured going forward, which in turn will affect asset utilisation and the network need for some assets in the Latrobe Valley. This VAPR identifies that each configuration will present different flow patterns and limitations and therefore further investigations is needed to define the optimal operational configuration.
  - The 2022 ESOO forecasts that generation retirements will see unserved energy in Victoria exceed the reliability standard after 2028-29, highlighting an urgent need for more generation, storage and transmission. AEMO is also investigating further opportunities to mitigate against an indicative reliability gap, including options to unlock Victorian generation by investing in solutions that relieve identified limitations.

AVP's *Transmission Development Plan for Victoria* has been 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 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 and changes to the *Transmission Development Plan for Victoria*.

The VAPR provides an opportunity to build on these investigations, and undertake a full review of the Victorian power system. The VAPR uses detailed analysis to capture the nature, timing, impact, and triggers associated with potential limitations, which also informs 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.

4.1 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.

4.1.1 DSN augmentation planning approach

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

- Reviewing historical network performance over the previous year (See Chapter 2).

- Reviewing future network performance under a range of demand and generation scenarios considering government policy and economic growth projections through exploratory studies (See Chapter 3).

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 for that location for at least 99% of a year.
- 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[78].
- Has not maintained stable voltage control following a credible contingency event as outlined in S5.1.8 of the NER.
- Has a fault level shortfall as outlined in S5.20C.3 of the NER.
- Has a heavily restricted outage window due to other constraints and limitations.

Exploratory 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 when expected changes in generation, demand, or other planning inputs are likely to have a significant impact on the flow patterns and behaviour of the system.

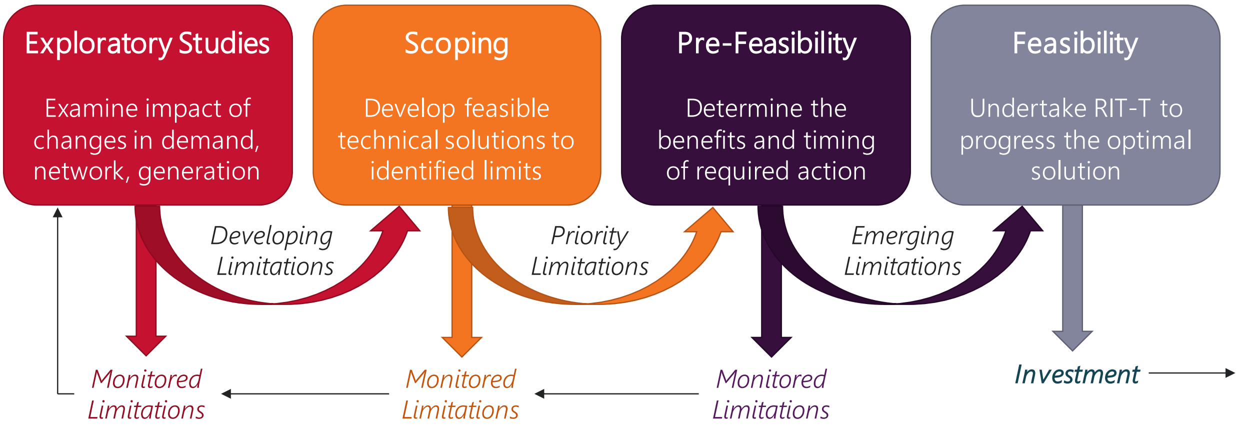
Screening studies identify limitations by assessing network performance in terms of security and performance obligations under a range of different power system configurations. Security and performance obligations define the transmission system's technical limitations (for example, voltage ranges, stability 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 solution options to address the identified limitations, then estimates the costs of the solution options, and assesses the likelihood of these delivering positive net market benefits. Based on these assessments, the limitations are categorised as shown in Figure 31, and described below.

[78] 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 31 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, and where trigger conditions have been met. 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 chapter.

A complete list of the identified emerging, priority, developing, and monitored transmission network limitations is given in Appendix A2. Appendix A3 has more information on AVP's approach to transmission network limitation reviews.

4.2 Emerging limitations

AVP has conducted a combination of power flow modelling and economic assessments to identify new network limitations, following the methodology described in Section 4.1. These studies include all committed and anticipated developments listed in Section 3.4.2.

There were no emerging limitations identified in the 2021 VAPR. AVP has identified three emerging limitations in the 2022 VAPR, as described in Table 15, and expects to commence feasibility assessment, including RIT-Ts if necessary, to identify the preferred option to address these limitations in early 2023.

Table 15 New emerging limitations

#	Limitation (conditions)	Category		Description/next steps
		2021	2022	
1	**Minimum fault level requirements at Thomastown, Moorabool and Hazelwood fault level nodes** (caused by lower demand and early retirement of thermal generators)	Developing	Emerging (new)	This system strength shortfall was declared in AEMO's *Update to 2021 System Security Reports*. AVP is progressing activities to address the system strength shortfall declarations, with options analysis expected to commence in early 2023.
2	**High voltages in Metropolitan Melbourne and South West Victoria** (caused by low and negative demand conditions forecast in the 2022 ESOO over the next decade).	Priority	Emerging (new)	AVP will conduct further prefeasibility studies considering the latest forecasts with the intention of commencing a RIT-T thereafter (see Section 2.4 for further information).
3	**Metropolitan Melbourne area voltage stability** (caused by aging capacitor banks and high demand conditions forecast in the 2022 ESOO over the next decade).	Monitored	Emerging (new)	AVP is investigating options to ensure sufficient reactive power support will be available to manage this limitation going forward.

4.3 Priority limitations

AVP has not identified any new priority limitations in the 2022 VAPR.

Out of the five priority limitations identified in the 2021 VAPR, four are now monitored limitations following recent announcements of the RDP Stage 1 projects (see Table 17) and one is a new emerging limitation (see Table 15).

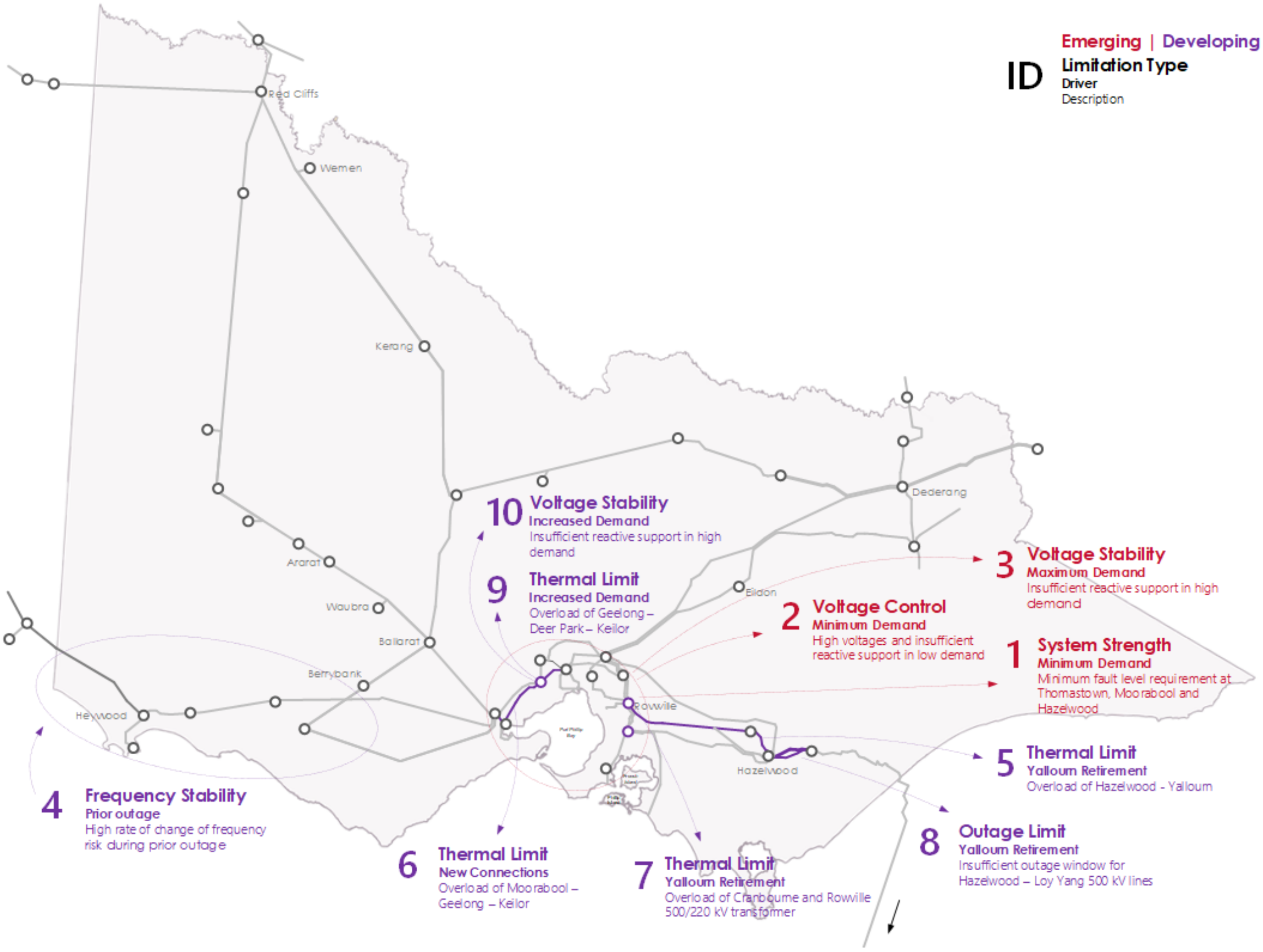
4.4 Developing limitations

In addition to the three emerging limitations, seven developing limitations are currently under investigation. Of these, five were identified in past VAPRs (predominantly due to uptake of generator connections in regional areas, increasing maximum demand and decreasing minimum demand, and the announced retirement of Yallourn Power Station in 2028) and two are new developing limitations (which are driven by increased load in Metropolitan Melbourne, specifically at Deer Park Terminal Station). These are shown in Table 16.

Table 16 New and existing developing limitations

#	Limitation (conditions)	Category		Description/next steps
		2021	2022	
4	**High rate of change of frequency (ROCOF) in South West Victoria** (constraining generators on the 500 kV lines west of Moorabool during prior outage of one of these lines, and for credible trip of another).	Developing	Developing	AVP will continue heightened active monitoring and reassess the potential benefits of implementing a post-contingent generation tripping scheme.
5	**Overloading of Hazelwood – Yallourn 220 kV lines** (post Yallourn Power Station retirement).	Developing	Developing	AVP will conduct an assessment on the alternative operating configuration in the Latrobe Valley and continue its investigation into challenges associated with the announced retirement of Yallourn Power Station, including assessment of the benefits from credible augmentation options if necessary. Further connection of BESS including the anticipated Wooreen energy storage system to the 220 kV network in the Latrobe Valley will assist in alleviating this limitation.
6	**Overloading of the Moorabool – Geelong – Keilor 220 kV lines for a credible contingency (trip of the other Moorabool – Geelong – Keilor 220 kV line)** (due to high generation in South West Victoria and Western Victoria as well as high demand in Greater Melbourne).	Developing	Developing	AVP will continue heightened active monitoring and reassess the benefits of potential control schemes and other network solutions as more generation connects and becomes committed in South West and Western Victoria. More information can be found in Section A2.6.
7	**Overloading of Cranbourne and Rowville 500/220 kV transformers** (post Yallourn Power Station retirement).	Developing	Developing	AVP will conduct an assessment on the alternative operating configuration in the Latrobe Valley and continue its investigation into challenges associated with the retirement of Yallourn, including assessment of the benefits from credible augmentation options if necessary.
8	**Insufficient outage window on the Hazelwood – Loy Yang 500 kV lines** (decreasing minimum demand, increasing duration of low demand periods, and post Yallourn Power Station retirement).	Developing	Developing	The challenges are highlighted in Section 4.5.6. AVP will continue its investigation into challenges associated with the retirement of Yallourn. Further installation of BESS including the anticipated Wooreen energy storage system project will assist in alleviating this limitation.
9	**Overloading of the Geelong – Deer Park or Deer Park – Keilor 220 kV lines for a credible contingency (trip of the other line)** (Increased demand at Deer Park).	Monitored	Developing (new)	This limitation is separate to limitation #6, in that this is solely a Deer Park load driven constraint, while limitation #6 is driven by increased demand in the general Metropolitan area when supplied by generation in Western Victoria via the Moorabool – Geelong – Keilor 220 kV corridor. AVP will assess the benefits of potential control schemes and will liaise with relevant network service providers further to manage this limitation.
10	**Insufficient reactive support at Deer Park Terminal Station** (increased demand at Deer Park).	Monitored	Developing (new)	AVP will assess the benefits of potential network and non-network solutions, including post contingent load shedding control schemes and additional voltage support, and will liaise with relevant network service providers to manage this limitation.

Figure 32 Emerging limitations and developing limitations under investigation



4.5 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 to justify the cost of relieving the limitation.

Solutions to address some of the priority and developing limitations identified in the 2021 VAPR have been assessed as part of the recently announced RDP Stage 1 projects. Where a limitation is being considered under the RDP, the relevant RDP project will partially or fully alleviate the limitation, depending on both how much the project initially intended to resolve the limitation, and how the limitation evolves post implementation of the RDP projects – particularly where the drivers are changing in demand or uptake of generator connections.

The following limitations identified in the previous VAPRs have been reclassified from priority or developing to monitored limitations due to updated status of DSN augmentation projects, mostly RDP Stage 1 projects.

Table 17 Limitations identified in the past VAPRs and re-classified to monitored limitations

Limitation (conditions)	Category		Description/reasons for reclassification
	2021	2022	
Overloading of the Ballarat – Berrybank – Terang – Moorabool 220 kV line for a credible contingency (trip of the Moorabool – Terang line) (due to new generator connections).	Priority	Monitored	A NCIPAP project to increase the rating of this line was completed in 2020-21, and a further post-contingent tripping scheme is being pursued as part of the RDP Stage 1 minor augmentation projects. These projects are anticipated to alleviate the limitation. This limitation can be further relieved by implementing possible network solutions highlighted in Section A2.5.
Overloading of the Murra Warra – Horsham – Bulgana 220 kV line for a credible contingency (trip of the Bendigo – Kerang line) (due to new generator connections being established between Horsham and Kerang).	Priority	Monitored	Station upgrades to increase the line rating, a generator runback scheme and Murraylink runback scheme amendments, to quickly reduce line loadings, are being pursued as part of the RDP Stage 1 projects. These projects combined are anticipated to partially relieve the limitation. This limitation may further be relieved following the implementation of Project EnergyConnect, VNI West (subject to operating conditions), and network solutions highlighted in Section A2.7.
Voltage instability/collapse around Wemen Terminal Station for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line) (due to new connections being established between Kiamal and Wemen).	Priority	Monitored	In September 2022, as part of RDP stage 1, AVP contracted Edify Energy to provide system strength services from its Koorangie Energy Storage System (KESS), a grid-forming inverter battery energy storage facility currently being developed near Kerang on the Kerang – Wemen 220 kV line. The KESS will provide system strength services from 2025, but may also be capable of alleviating this voltage instability/collapse limitation. This limitation may further be relieved following the delivery of Project EnergyConnect.
Overloading of the Red Cliffs – Wemen – Kerang – Bendigo 220 kV line for a credible contingency (trip of the Horsham – Murra Warra – Kiamal 220 kV line) (due to new connections between Kiamal and Kerang).	Priority	Monitored	A NCIPAP project to alleviate this limitation was completed in August 2021, and a control scheme change is currently undergoing commissioning to reduce overloading conditions of this line. The NCIPAP and control scheme change projects are anticipated to alleviate the limitation. This limitation can be further relieved by implementing possible network solutions highlighted in Section A2.4.
Overloading of the Dederang – Glenrowan – Shepparton – Bendigo 220 kV line for a credible contingency (trip of one of the other Dederang – Glenrowan 220 kV lines) (due to high New South Wales to Victoria imports, increased maximum demand and generation in regional Victoria).	Developing	Monitored	An RDP Stage 1 Central North REZ minor augmentation project is being considered to address this limitation.
Overloading of the Moorabool 500/220 kV transformer for a credible contingency (tripping of the other Moorabool 500/220 kV transformer) (due to new connections on the 500 kV lines west of Moorabool, which may require generators on these lines to be constrained).	Developing	Monitored	An RDP Stage 1 – South West REZ minor augmentation project to upgrade limiting plant is being considered to address this limitation.
Voltage collapse limitation in South West Victoria (tripping of the Moorabool – Mortlake 500 kV line).	Developing	Monitored	Due to additional generator connections and under high import from South Australia. AEMO has recently developed a constraint to manage this limitation, and a Mortlake turn-in project is being considered to address this limitation further. More information is listed in Section 4.5.5.
Voltage oscillation in western and north-western Victoria (during prior outages for a credible contingency).	Developing	Monitored	This limitation was identified in the 2019 VAPR as a new monitored limitation. As shown in Section 2.6, this limitation was the top binding limitation. This constraint bound frequently due to a number of network outages required to facilitate generator connection projects. The RDP Stage 1 project to strengthen the system at the Western Victoria and Murray River REZs will help reduce the impact of this limitation. This limitation will be relieved further following the implementation of Project Energy Connect.

AVP will monitor the operating conditions and assess these limitations in the next VAPR. AVP also welcomes feedback from stakeholders and non-network service providers on credible options which would deliver positive net market benefits.

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 Section 4.6 and Appendix A2.

The following sections provide more detail on the 2022 VAPR's assessment of monitored limitations.

4.5.1 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, as well as strong uptake of distributed PV which results in a decline of minimum operational demand, and other drivers of demand such as projected growth in base load, electric vehicles, and electrification which results in increased maximum operational demand.

In 2021-22, 2.4 GW of new generation projects connected in Victoria, and new projects continue to be proposed in regional parts of the state, where high-quality solar and wind resources are abundant. These parts of the network, however, were not originally designed to support such high connection 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 Chapter 3).

In the 2022 VAPR, AVP has not identified any new thermal limitations that were not already identified in previous VAPRs. However, AVP has re-classified the categories of some previously identified limitations (see Table 16 and Table 17).

4.5.2 System strength limitations

Under the AEMC's final determination on efficient management of system strength on the power system[79], AVP (as the System Strength Service Provider [SSS Provider] in Victoria) is required to provide the right amount of system strength to support the forecast connection of IBR.

Declared and near-term shortfalls

On 13 December 2019, AEMO published a notice of fault level shortfall[80] at Red Cliffs Terminal Station and further revised this shortfall on 6 August 2020 due to a change in requirements at the Red Cliffs node[81]. The revised notice specified an immediate fault level shortfall (also referred to as a system strength gap) of at least 66 MVA, which would continue beyond 2024-25 if not addressed. AVP has addressed this shortfall via system strength services contracts that will continue until at least mid-2025, as outlined in Section 3.4.1.

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

[80] AEMO, *Notice of Victorian Fault Level shortfall at Red Cliffs*, December 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice_of_Victorian_Fault_Level_Shortfall_at_Red_Cliffs.pdf.

[81] AEMO, *Notice of Change to System Strength Requirement and Shortfall at Red Cliffs*, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en&hash=5C3EDDABDF81891B3989F6FF0466C486.

Looking forward, the *AEMO's Update to 2021 System Security Reports*[82] identified system strength shortfalls as summarised in Table 18.

Table 18 Declared system strength shortfalls

Node	Shortfall timing	Fault level requirement (MVA)	Shortfall size (MVA)
Hazelwood	1 July 2026	7,150	203
Thomastown	1 July 2026	4,500	279
Moorabool	1 July 2026	4,050	31

AEMO, as national planner, has declared these new system strength shortfalls at Hazelwood, Moorabool and Thomastown under the *Step Change* scenario which forecasts earlier coal generation retirements and greater VRE penetration, compared to the *Progressive Change* scenario used in the previous *System Security Report*s.

AVP will commence a feasibility assessment, including a cost-benefit analysis, to identify how best to address the system strength shortfall declarations.

System strength Rule change

On 21 October 2021, the AEMC made a final determination on the efficient management of system strength on the power system[83]. Tackling system strength from the supply side, demand side, and a coordination perspective, the new framework aims to provide a more forward-looking, coordinated solution to the supply and demand of system strength in the NEM. The new framework requires SSS Providers to supply sufficient system strength to meet forecast IBR connections, IBR connecting parties to meet new requirements intended to reduce their system strength demand, and system strength demanders to contribute to the SSS Provider's expected costs for procuring system strength services to ensure consumers do not directly fund all system strength investments or bear the financial risk of stranded assets.

The Rule introduces a new obligation on AVP, as SSS Provider for Victoria, to meet the system strength standard which aims to provide the right amount of system strength to support the connection of IBR in Victoria as forecast by AEMO. It requires AVP to use reasonable endeavours to plan and procure system strength services that meet the system strength requirements forecast and published annually by AEMO. The system strength requirements include, at each system strength node, a forecast of the minimum three phase fault level and the projected level and type of IBR and market network services facilities, to be used by AVP for the purposes of meeting the system strength standard.

The new Rule obligation will take effect on 1 December 2022, with system strength services provided no later than 2 December 2025.

Commencing on 15 March 2023, the demand side and coordination arrangements of the new framework will allow new connecting parties demanding system strength to either self-remediate their system strength impact or pay a system strength charge to access the system strength services provided by AVP. AVP will also be responsible for setting Victoria's system strength charge in line with the NER, the AER's Transmission Pricing Methodology Guideline, and AEMO (national planner) guidance. AVP is currently working with the other SSS Provider in revising the pricing methodology to set out how system strength unit prices will be provided.

[82] AEMO, Update to 2021 System Security Reports, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/update-to-2021-system-security-reports.pdf?la=en.

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

Projected shortfalls beyond 2026

Beyond the five-year timeframe considered in the *Update to 2021 System Security Reports*, which declared system strength shortfalls by July 2026, the 2022 ISP[84] projected, but did not declare, increased shortfalls at the Hazelwood 500 kV, Moorabool 220 kV, and Thomastown 220 kV nodes due to Yallourn Power Station's retirement and a further decline in synchronous generation in Victoria, in line with the *Step Change* scenario. These further shortfall projects are presented in Table 19.

Table 19 Potential system strength shortfalls

Node	2029-30	2034-35
Hazelwood	3,050 MVA potential shortfall	4,650 MVA potential shortfall
Thomastown	900 MVA potential shortfall	1,600 MVA potential shortfall
Moorabool	1,200 MVA potential shortfall	2,050 MVA potential shortfall

REZ Development Plan system strength project

In August 2021, the Victorian Government asked AVP, as part of its RDP, to progress with procurement activities for services to strengthen the system to facilitate new generation connections at Murray River, Western Victoria and South West Victoria REZs.

As presented in Section 3.4.3, Edify Energy's KESS was contracted in September 2022 as part of RDP Stage 1 to provide system strength services through the 125 MW grid-forming inverter battery energy storage facility to be developed near Kerang. The facility will connect into the Kerang – Wemen 220 kV line. A 20-year System Support Agreement will commence from 2025.

Minimum synchronous unit requirements

Given rapid increases in renewable generation, coupled with falling minimum demands, there are likely to be times over the coming decade where surplus generation is available that cannot be exported across the interconnectors, resulting in units being decommitted (below their minimum stable generation levels), or spilled wind and solar resources.

At these times, the units with the highest bid prices will generally have their output reduced first. However, the Victorian region also has a requirement to maintain a minimum number of synchronous units online for system strength purposes[85]. There are currently 39 combinations of synchronous units that meet this requirement, and at current demand levels it is rare that none of these 39 combinations of synchronous units is available (see Section 2.5.3). If pre-dispatch analysis indicates that these minimums are unlikely to be met (that is, the system strength limitation becomes violating), either pre-contingent or within 30 minutes following a credible contingency, the System Operator may direct an appropriate synchronous generator to come online.

As minimum demands fall in future, it may become increasingly difficult to maintain this minimum requirement – particularly at times of high renewable generation availability where synchronous units will begin to be displaced from the dispatch stack. At these times, renewable generation output may need to be reduced to give way to synchronous generation, to ensure system strength requirements are met.

[84] See 2022 ISP appendix A7 Power System Security, p.28.

[85] AEMO, *Transfer Limit Advice – System Strength*, July 2021, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

Minimum operational demand assessment to maintain system strength

The synchronous machine combinations required to maintain sufficient system strength in Victoria have an aggregate minimum generation requirement of 700 MW to 1,600 MW. During times when Victorian operational demand falls below this threshold, Victoria must export surplus generation to neighbouring regions.

The 2022 ESOO demand forecasts indicate that Victorian demand will fall within the aggregate minimum generation range for synchronous machine combinations from 2024-25 in the Central scenario (in line with the *Step Change* scenario in the 2022 ISP), and below this threshold range from 2027-28.

That means within the next few years there is potential for demand levels to occur that would be insufficient to absorb the aggregate minimum generation with the currently available minimum synchronous unit combinations. While exports to neighbouring regions would enable more synchronous generation to meet minimum operating limits, this would be limited at times of coincident low demand in Victoria and other NEM regions.

AEMO and AVP are working collaboratively to identify any new minimum system strength unit combinations, as well as assessing a range of minimum demand thresholds under which the Victorian network can operate securely under various conditions.

In parallel, AVP is progressing activities to address the existing system strength shortfall declarations at Hazelwood, Moorabool and Thomastown. In addressing these shortfalls, AVP will consider options that are capable of providing increased system strength services without generating power, which may include conversion of existing generators to synchronous condensers, and the installation of new or service contracting of existing synchronous condensers or grid-forming BESS. If appropriately incentivised, the capacity of grid-forming BESS can be increased as part of the Victorian Government's recently announced storage targets to enable at-least 2.6 GW of energy storage capacity by 2030 and 6.3 GW by 2035.

Figure 33 presents the forecast minimum operational demand compared to the minimum generation requirements threshold range, thus demonstrating where there would be an increased risk of violating network security limits.

AEMO is investigating measures to improve challenges associated with Under Frequency Load Shedding (UFLS) at times of low demand, to ensure the adequacy of UFLS schemes[86].

AEMO is also investigating additional options that do not relate to the Victorian DSN, including:

- Management of DER in the distribution network through systems like Project EDGE[87] and DER management platforms.
- Emergency backstop PV curtailment capability as a last resort.

[86] See https://aemo.com.au/-/media/files/initiatives/der/2021/vic-ufls-data-report-public-aug-21.pdf?la=en&hash=A72B6FA88C57C37998D232711BA4A2EE.

[87] See https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge.

Figure 33 Minimum operational demand thresholds in Victoria, 2019-20 to 2033-34

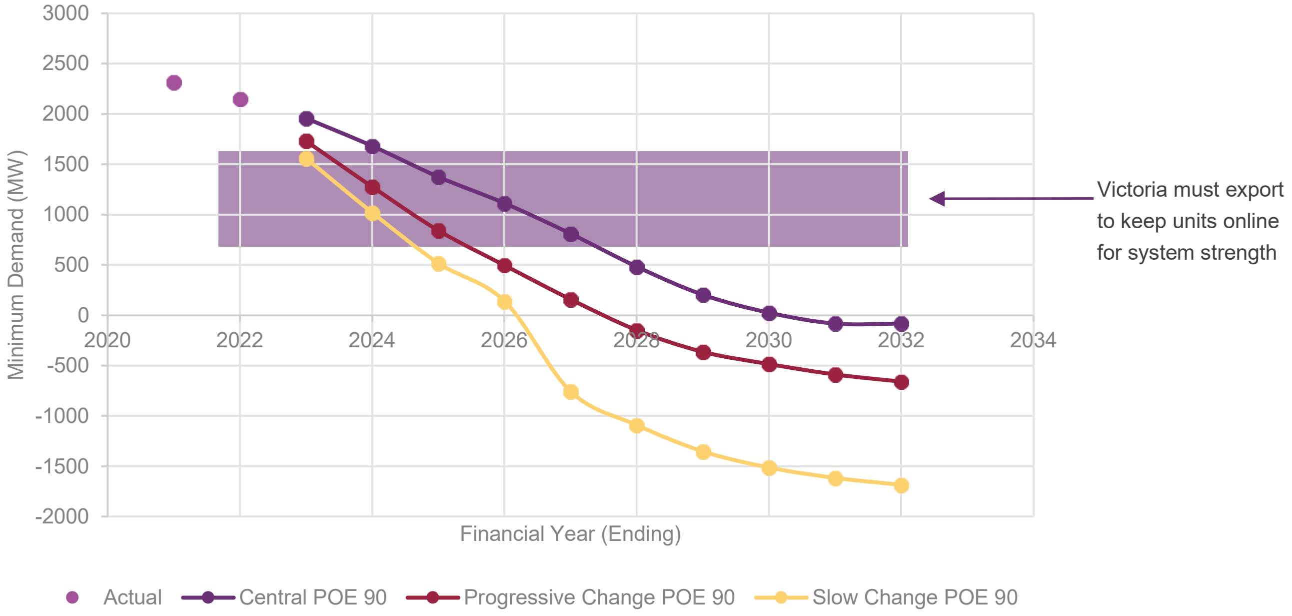
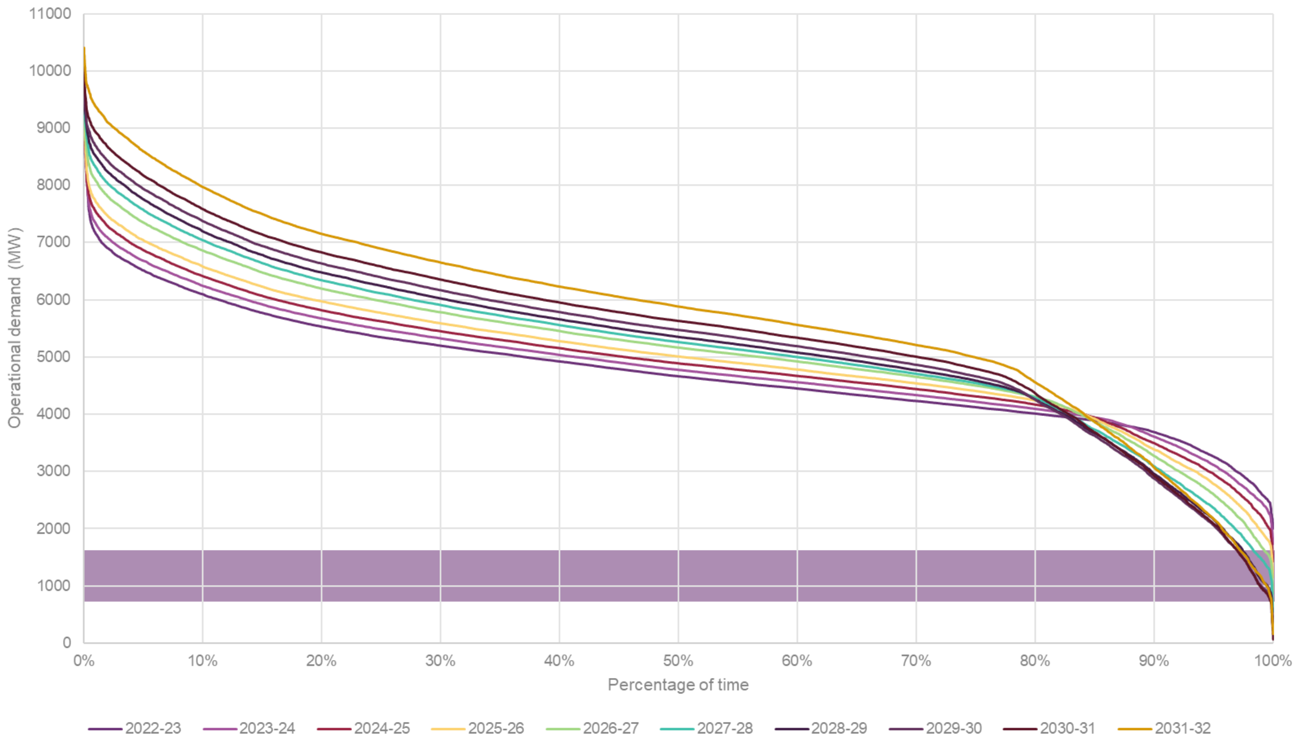


Figure 34 Operational demand projection duration curves by financial year



From 2022 ESOO, 50% POE operational demand forecasts.

4.5.3 Inertia (high rate of change of frequency [ROCOF]) limitations

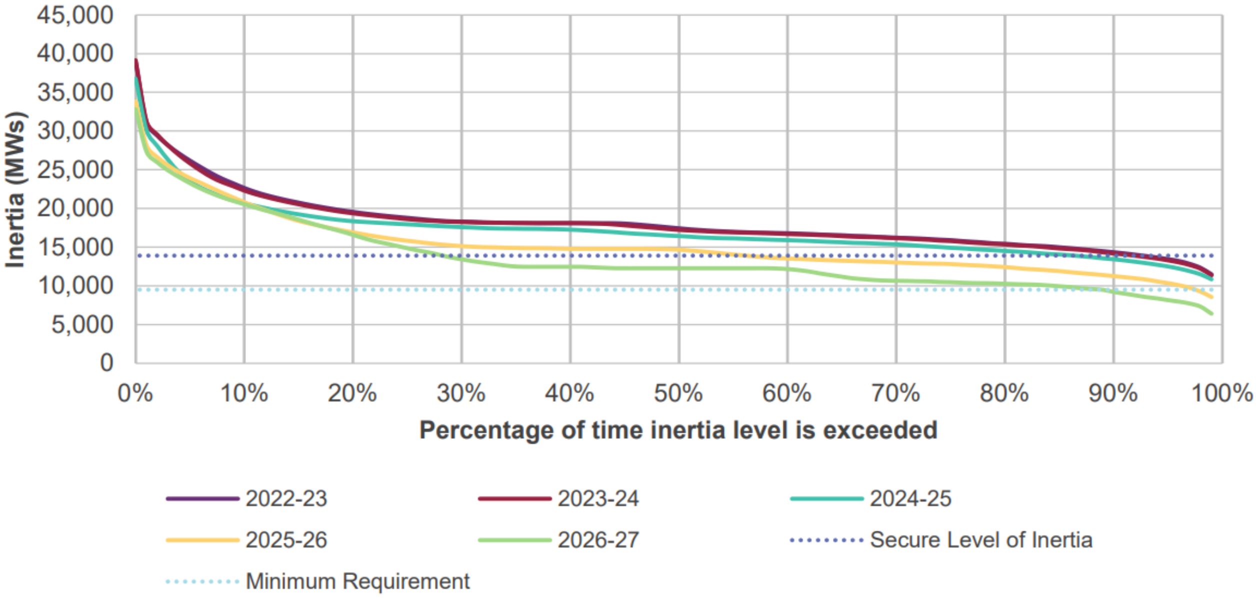
Power systems with high inertia can resist large changes in system frequency arising from contingency events that create an imbalance between supply and demand.

With the increase in DER 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[88]), 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 *Update to 2021 System Security Reports*[89], AEMO:

- Identified a strong decline in inertia for Victoria, and 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 35.
- Did not declare an inertia shortfall for Victoria, because this region is not considered sufficiently likely to be islanded from the NEM under the current application of the existing framework[91]. This is due to its strong interconnection with neighbouring regions. The VNI West project is likely to further strengthen interconnection and reduce Victorian inertia risks late in the decade.

Figure 35 Projected inertia for the five-year outlook, *Step Change* scenario, Victoria



MWs: megawatt seconds.

Beyond the five-year outlook, the inertia shortfall is forecast to grow due to the Yallourn Power Station retirement and projected further decline in synchronous generation in Victoria in the 2022 ISP *Step Change* scenario.

[88] 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.

[89] AEMO, *Update to 2021 System Security Reports*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/update-to-2021-system-security-reports.pdf?la=en.

4.5.4 High voltage limitations

The 2021 *System Security Reports*[90] did not identify any Network Support and Control Ancillary Services (NSCAS) gaps related to voltage limitations in the Victorian region for the next five years, assuming pre-contingent switching of the Hazelwood – South Morang 500 kV transmission line for voltage control.

The findings in this report were based on the *Progressive Change* scenario and forecasts, as this was deemed the most likely scenario at the time. Since this report, the *Step Change* scenario was identified as the most likely scenario for AEMO's 2022 ISP, and used as the Central scenario in the 2022 ESOO.

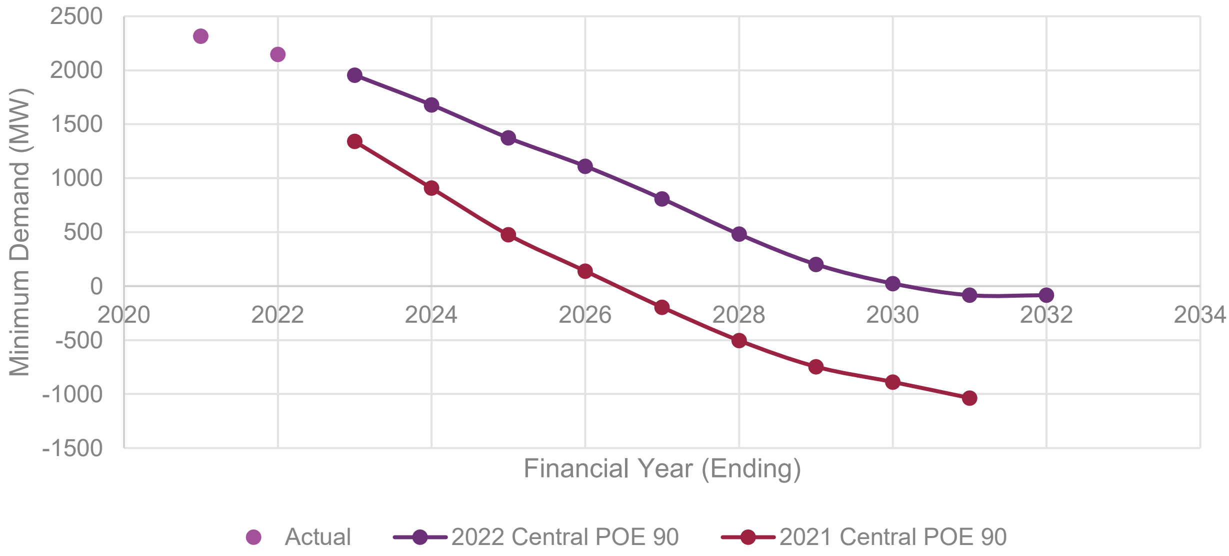
A further assessment has been undertaken for this VAPR to review voltage limitations under the 2022 ESOO *Central (Step Change)* and *Progressive Change* scenarios, and to provide an update to the high voltages limitation identified in the 2021 VAPR due to decreasing minimum demand. Outlooks are presented below for the immediate term (present to 2025), short term (2025-27), and long term (2027-32).

High voltages in Metropolitan Melbourne and South West Victoria

The Victorian DSN experiences high voltages during minimum demand conditions, particularly in the Metropolitan Melbourne area and the south-west transmission corridor. AEMO has historically managed this by operational intervention, including 500 kV transmission line switching and utilising an NMAS contract for reactive services. AVP's Victorian Reactive Power Support project (see Section 3.4.1) has delivered additional reactive support in the area as of Q3 2022, to improve voltages in the area and reduce the need for operational intervention in the immediate term.

AEMO continues to monitor actual demand trends against demand forecasts. The 2022 ESOO forecasts further declines in minimum demand, shown in Figure 36. It is worth noting that while the 2022 ESOO forecasts still show a trend of further decline in minimum demand, the projected decline is significantly slower than in the 2021 ESOO.

Figure 36 Forecast 90% POE summer minimum operational demand (sent-out) for Victoria in the 2022 ESOO and 2021 ESOO Central scenario, 2019-20 to 2033-34



[90] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/Operability/2020/2020-NSCAS-Report.

In the next eight years, minimum operational demand is forecast to decline rapidly due to the projected uptake of distributed PV. This decline is expected to continue, including potential negative demand from 2031 in the ESOO Central scenario. However, the rate at which minimum demand declines is expected to slow, due to the uptake of distributed PV being increasingly offset by the uptake of large-scale storage, electric vehicles (EVs) and electrification (switching to electricity from other fuels).

AVP has performed an assessment of reactive power needs in Victoria over the next 10 years, using the 2022 ESOO forecasts. This assessment signals the potential need for further investment in the next five years, as summarised in Table 20.

The main drivers for the additional reactive power capability requirement are further forecast decline of demand, the subsequent need to restrict the number of online synchronous generating units, and the retirement of Yallourn Power Station. AVP projects that up to 550 MVAr of additional reactive power capability will be required to manage voltages within operating limits post contingency.

The most onerous contingencies were identified to be the loss of the 500 kV line from Tarrone (TRTS) – Heywood (HYTS) – Alcoa (APD) with the subsequent trip of APD load (as per the permanent reclassification[91]), or the loss of a synchronous machine and its associated auxiliary load which provided the largest absorption reactive power.

It is important to note that while there are forecast needs for reactive support in future, the potential needs are forecast to be less than anticipated in the 2021 VAPR. This is due to the minimum demand levels forecast in the 2022 ESOO being higher, and declining more slowly, than reported in the 2021 ESOO.

As the findings in Table 20 show, there is a potential need for reactive support in the immediate term (in the next three years) under conservative conditions, however it was found that this shortfall of reactive support can be managed through operational intervention and reliance on reactive support from plant in the Latrobe Valley, South West Victoria, and the Metropolitan area.

In the short term (in four to five years), the need for reactive support is forecast to increase, due to a further forecast decline in minimum demand and the reduction in total synchronous generation units able to operate at these demand levels. Based on this, with operational intervention and reliance on reactive support from plant in the Latrobe Valley, in South West Victoria, and in the Metropolitan area, there is still a potential reactive shortfall AVP will commence a RIT-T in early 2023 to identify the preferred option to address this need for additional reactive power support.

In the long term (in six to 10 years), the need for reactive support is forecast to be further exacerbated by a projected decline in minimum demand to negative demand levels (which in turn further limits the total number of synchronous generating units able to be online), as well as the retirement of Yallourn Power Station. With operational intervention and the reliance on reactive support from plant, there is a potential reactive shortfall that may need to be addressed through a RIT-T.

The identified potential reactive need in the next four to 10 years is based on existing and committed generator projects, retirements and transmission projects only. The need and size of reactive support that may be delivered through a RIT-T may vary depending on future generation projects and their reactive capability, as well as future transmission projects and retirements, including those mapped in the 2022 ISP's roadmap. Developments in the 2022 ISP that may have a significant impact on the size of reactive support needed include, but are not limited to:

- Early retirements including Loy Yang Power Station.

[91] See AEMO Market Notice 45245, at https://aemo.com.au/market-notices.

- Reactive power capability from additional renewable generators.
- Transmission projects including VNI West and MarinusLink.

AVP will continue to investigate the need for additional reactive support in the immediate and short-term following this VAPR, with the intention of commencing a RIT-T in early 2023.

Table 20 Additional reactive power need in Victoria for the next 10 years

Outlook	Identified additional reactive power need (Central [*Step Change*] scenario)	Drivers for the additional need	Mitigation measures/actions
Immediate term (present to 2025)	Up to an additional 200 MVAr absorption reactive power.	Further decline of operational demand in 2022 ESOO to as low as 1,373 MW.	Utilisation of existing operational measures, including the switching of a 500 kV line, and dispatch of reactive capability from generation plant via AEMO's VAr Dispatch System (VDS).
Short term (2025-27)	Up to an additional 350 MVAr absorption reactive power from status quo.	Further decline of operational demand in ESOO 2022 to as low as 809 MW.	The above measures, plus: AEMO has classified this need as an emerging limitation with the intention of commencing a RIT-T in early 2023 to consider investment in additional reactive power support.
Long term (2027-32)	Up to an additional 550 MVAr absorption reactive power from status quo.	Further decline of operational demand in 2022 ESOO to as low as -84 MW. Retirement of Yallourn Power Station from 2028.	The above measures, plus: AEMO will continue to monitor changes in the network and demand forecast, and consider further investment in additional reactive power support if necessary. Utilisation of reactive capability of new generation and energy storage in Latrobe Valley and South West Victoria.

High voltage at Eildon Power Station

There has been no change to this issue since the 2021 VAPR. During periods of low demand and low power transfer between Victoria and New South Wales, high voltages may be experienced in the DSN at Eildon Power Station (EPS) and nearby stations.

This high voltage issue has been successfully managed by operational measures and AVP has not identified a need for any further network or non-network investment to address these issues in the near-term future.

4.5.5 Stability limitations

South West Victoria stability limitation

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.

AVP investigated this limitation further and identified that a voltage instability issue exists for a single credible contingency of the Moorabool – Mortlake or Moorabool – Haunted Gully 500 kV line under certain operating conditions. Investigations also confirmed that the voltage collapse is expected to eventuate during periods of high import from South Australia across the Heywood interconnector coinciding with high generation in South West Victoria. A reduction or loss of (APD) load would have a similar impact as additional generation in the area on this limitation.

With existing and committed generation, this limitation can be managed by operational measures such as constraints on local generation and/or South Australia import via Heywood. AVP has recently developed a constraint to manage this limitation. The severity of this limitation will be better understood based on the binding information of this constraint equation.

As the 2021 VAPR noted, AVP has reclassified the loss of the APD load with a single contingency of the Moorabool – Mortlake or Moorabool – Haunted Gully 500 kV line to be credible. Investigation into the impact of this reclassification has indicated adverse impact on this voltage instability limitation, resulting in the introduction of the constraint equation(s) to manage the limitation operationally where the reclassified credible contingencies were considered as the critical contingencies[92].

As outlined in Section 3.4.3, in October 2022 AusNet Services was contracted by AVP to turn-in the Haunted Gully to Tarrone 500 kV line at Mortlake by the end of October 2025. Connecting this second circuit at Mortlake Power Station will allow a more balanced sharing of power between the two parallel circuits of the Moorabool to Heywood 500 kV double circuit line and shorten the electrical distance of power transfer following a network outage, thus mitigating this South West voltage stability limitation by improving voltage stability in the South West REZ. The turn-in project is expected to allow up to 1,500 MW of additional generation output following its commissioning.

Melbourne Metropolitan Area voltage stability limitation

With increased maximum demand as forecast in the 2022 ESOO, the Melbourne Metropolitan area may experience low voltages and voltage stability issues at times of high demand within the next 10 years. See Appendix A2 for the relevant limitation. There are a number of existing capacitors in the area to support voltages during these high demand periods, but these capacitors are approaching the end of their contracted life. AVP has conducted a review which has determined the continued need for these capacitors going forward, and is investigating the options post the contract expiry to ensure sufficient reactive power support will be available to manage this limitation.

AVP will continue to monitor this limitation in line with forecast maximum demand, and will take further timely action if necessary.

4.5.6 Outage window limitation

Transmission network outages are necessary for maintenance work, repair and augmentations to maintain system reliability. However some outages can only be planned for within a certain operational demand window, and as such, these outages may not proceed or may have to be withdrawn during any periods where operational demand falls outside these windows. As high demand periods progressively rise and low demand periods progressively decrease, the periods outside these windows become more frequent, and outage planning as a result becomes more challenging.

The outage of one of the 500 kV lines between Hazelwood Terminal Station (HWTS) and Loy Yang Power Station (LYPS) has been identified previously as becoming more challenging to plan for due to increasing number of and high and low demand days. A credible contingency during this outage requires significant reduction in LYPS unit output and disconnection of Basslink to manage power system security. As a result, currently during periods when operational demand is approaching approximately 6,000 MW or above, or 3,000 MW or lower, this outage may be

[92] Victorian Transfer Limit Advice – System Normal – August 2022, AEMO, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/victorian-transfer-limit-advice-system-normal.pdf?la=en.

difficult to schedule due to challenges in post-contingent reserve management to avoid load shedding during high demand periods and voltage management and system strength during low demand periods.

At any particular time, however, the exact level of demand window outside which this outage could not proceed is dependent on a variety of factors. For the upper bound of the window, the key factors include:

- The available generation capacity and interconnector capability.
- The intraregional network constraints.

Section 4.6.4 (under Outage Window) of the 2021 VAPR has more information on assumptions behind the calculation of the upper bound threshold of 6,000 MW for the existing power system, and how this threshold could be affected by future generation retirement (such as Yallourn Power Station) and future renewable generation.

For the lower bound of the window, the key factors affecting the threshold value of 3,000 MW include:

- The amount of reactive demand in the network.
- Available reactive support from other plant in Victoria.
- Victorian system strength.
- The available measures for further operational intervention, such as switching of additional 500 kV lines.

In addition to the HWTS-LYPS line outages, AEMO Operations and Ausnet Services have experienced difficulties in scheduling other planned outages due to various operational challenges.

An example was the planned outage for the necessary work to reconnect the 500 kV lines between Heywood and Moorabool after the lines were damaged by severe weather conditions. This outage required a long continuous duration without a pre-agreed recall time, resulting in challenges associated with South Australian system security and maintaining the reliability of supplying APD load following a credible contingency during the outage period.

Another example is 220 kV line outages in north-west Victorian network requiring renewable generators in north-west Victoria and south-west New South Wales to be constrained to avoid voltage oscillation during the outage periods.

AEMO will continue to monitor changes in operating conditions and work closely with AEMO Operations to manage the impact on necessary network outage planning.

4.6 Generation changes in ISP optimal development path

AGL has announced that all four units (2,200 MW) at Loy Yang A Power Station will be retired by 2035, Loy Yang B, owned by Alinta, has an expected closure date of 2047, and Newport Power Station (NPSD), owned by EnergyAustralia, has an expected closure date of 2039[93]. The *Step Change* scenario in the 2022 ISP – identified by stakeholders as the most likely scenario and used to identify the ISP's optimal development path – forecasts closure of all Loy Yang A and Loy Yang B units by 1 July 2032 and NPSD by 1 July 2030. This would bring forward the retirement of these generating units by a number of years compared to previously announced plans.

As part of this VAPR, AEMO assessed the impact of these projected early retirements on Victorian DSN performance, focusing on:

[93] AEMO, Generating unit expected closure year – July 2022, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2022/generating-unit-expected-closure-year.xlsx?la=en.

- Latrobe Valley DSN configuration.
- Network limitations.

The assessment of the impact of the retirement of all the Loy Yang A, Loy Yang B and NPSD generating units makes the following key assumptions for future generation and network projects:

- To maintain supply and demand balance, new generation is planted according to the generation outlook under the Optimal Development Path of the 2022 ISP at V2 (about 1,500 MW at 500 kV), V3 (about 650 MW at 220 kV), V4 (about 1,100 MW at 500 kV),V5 (about 2,000 MW at 500 kV) and V6 (about 300 MW at 220 kV)[94].
- All ISP committed, anticipated and actionable projects as per the optimal development path are delivered.
- The Wooreen Energy Storage System (350 MW/1,400 MWh[95]), proposed by EnergyAustralia, has been included and connected to Jeeralang Terminal Station (JLTS).

4.6.1 Impact on network limitations

The network limitations presented in sections 4.2, 4.3 and 4.4, which were identified and assessed without considering the early retirement of LYPS and NPSD, would be affected by the early retirements of Loy Yang A and B and NPSD, either directly or indirectly through the changes in supply as a result of the retirements.

This VAPR assessment found that (additional to the retirement of Yallourn Power Station, which results in limitations as described in Section 4.6 of the 2021 VAPR), the early retirements of Loy Yang A and B and NPSD are projected to:

- Relieve the limitations imposed from supply within the 500 kV network in the Latrobe Valley, due to less power transfer from this network.
- Deteriorate the thermal limitations within the greater Melbourne and Geelong area, due to less supply from the 220 kV network within this area to local load centres, resulting in higher transfer through corridors connecting other generation areas to the greater Melbourne and Geelong loads, such as the 500/220 kV transformations at MLTS, KTS, South Morang Terminal Station (SMTS), Rowville Terminal Station (ROTS), and Cranbourne Terminal Station (CBTS), and the MLTS-GTS-KTS 220 kV lines.
- Deteriorate the voltage stability, high voltage, and system strength limitations within the greater Melbourne and Geelong area due to less supply within its 220 kV network and subsequent loss of reactive power capability and fault current injection.
- Deteriorate the generation-driven thermal limitations in REZs Murray (V2) to Central North (V6) due to additional generation connection to displace the generator retirements, as outlined above.
- Deteriorate voltage limitations in South-West Victoria (see Section 4.5.5 for more information).
- Exacerbate state-wide system strength challenges due to a reduction in available generation unit combinations to meet the minimum generation unit requirements for providing minimum system strength requirements. As a result, the need for operator intervention or network investment to meet state-wide system strength requirements may accelerate.

[94] VRE output levels assessed are in line with average outputs of respective REZs at the time of maximum demand for Victoria from the ISP wind and solar traces.

[95] See https://www.energyaustralia.com.au/sites/default/files/2022-04/EA_069_WESS%20Fact%20Sheet_V9%20April%202022.pdf.

4.6.2 Next steps

AVP will continue to monitor the likely timing of generator retirements within Victoria and will assess associated limitations going forward.

4.7 Power System Frequency Risk Review (PSFRR)

The PSFRR is a biennial review of power system frequency risks associated with non-credible contingency events in the NEM. This 2022 review will be the final PSFRR; it will be replaced from 2023 with an annual General Power System Risk Review (GPSRR). AEMO, in its role as NEM Operator, undertakes this review in consultation with TNSPs. The PSFRR considers:

- Non-credible contingency events which AEMO expects would likely involve uncontrolled frequency changes leading to cascading outages or major supply disruptions.
- Current arrangements for managing such non-credible contingency events.
- Options for future management of such events.
- The likelihood of such events occurring.
- The performance of existing Special Protection Schemes (SPSs) and Emergency Frequency Control Schemes (EFCSs) which impact system frequency performance.

Further information on the PSFRR/GPSRR process, stages, and next steps are available on the AEMO website[96].

Relevant 2022 PSFRR recommendations:

Loss of both DDTS-SMTS 330 kV lines*: To avoid multiple transmission line loss following this non-credible event, the following improvements are recommended:*

a) *When Victoria is importing: The IECS scheme is used to manage the impact of the non-credible loss of both DDTS-SMTS 330 kV lines. The scheme is currently enabled only during bushfires in the vicinity of these lines and when Victoria is importing power from New South Wales. Considering the impact of this non-credible contingency event on the power system, it is recommended that AVP review the arming criteria.*

b) *When Victoria is exporting: It is recommended that AEMO (as Victorian transmission planner) modify or implement a new SPS similar to the present IECS to manage the non-credible loss of both DDTS-SMTS 330 kV lines when Victoria is exporting. It is recommended that AVP work with Transgrid to evaluate the benefit of augmenting this scheme to mitigate the impact of this non-credible event.*

The Interconnector Emergency Control Scheme (IECS) has been designed to respond quickly to multiple simultaneous transmission line contingencies by tripping selected Victorian load groups and generation to prevent Victorian separation from the rest of NEM due to cascade tripping as a result of instability.

Operation of the IECS could result in the tripping of more than 1,000 MW of load and 600 MW of generation in Victoria, so currently IECS is only armed during bushfires close to the monitored lines (the only identified condition under which the relevant non-credible contingencies may occur), to minimise the risk of tripping such a large amount of load and generation unexpectedly, due, for example, to human error or equipment/plant maloperation.

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

AVP has reviewed the risk assessment and found no evidence indicated any conditions other than bushfires could trigger the non-credible contingency events associated with IECS. As a result, AVP is of the view that current arming criteria are still appropriate; if the criteria were changed to arm the IECS normally, the risk of unexpected large-scale load and generation tripping would outweigh the benefit this change could deliver. AVP will continuously monitor the environment conditions and update the arming criteria if needs have been identified.

AVP has been discussing with TransGrid a joint planning project to investigate further the instability issues which was identified through high level PSFRR studies, to clarify and confirm this issue. Once the issues are confirmed, the next step is to investigate the potential to install a new control scheme to manage the instability issues, as recommended by the 2022 PSFRR.

Manage risks associated with non-credible loss of future North Ballarat – Sydenham 500 kV lines*: The Western Renewables Link is anticipated to be delivered and release full capacity by July 2026. This network reinforcement will enable greater transfer of generation from western Victoria to Melbourne by building a new 220 kV double circuit transmission line from Bulgana to a new terminal station north of Ballarat, and a new 500 kV double circuit line from north of Ballarat to Sydenham. The non-credible loss of the proposed 500 kV lines during periods when the new 500 kV flow exceeds the limits of the parallel 220 kV lines, could result in multiple line losses. AVP will consider this risk in the planning process.*

The 2022 PSFRR recommended AVP consider and manage the risks associated with non-credible loss of future North Ballarat – Sydenham 500 kV lines in the planning process. This recommendation is aligned with the common practice of AVP in planning the Victorian DSN to be assessed as part of the WRL project

4.8 Victorian control schemes

Following the review of the existing system protection and control schemes in 2019-20, AVP has further reviewed a number of control schemes to accommodate recent changes in local operating conditions and network configurations, as well as to address the 2022 PSFRR. Refer to Section 4.7 above for more information about the 2022 PSFRR recommendations.

AVP has also planned a review of the existing control schemes and an investigation into needs of new control schemes, taking into account committed network projects and generation connection projects, as well as other changes in operating conditions (see Chapter 3 for more information on committed projects), to both:

- Ensure any known or potential interactions between control schemes will not lead to cascading outages or major supply disruptions under the changed operating conditions.
- Increase transfer capability both intra- and inter-regionally.

4.9 Distribution 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. Appendix A1 includes information on constraints and augmentations identified in the 2021 Transmission Connection Planning Report, prepared by the Victorian DNSPs.

5 Asset replacement and retirements in the DSN

This chapter addresses NER requirements related to DSN asset retirement, deratings, and replacement.

Key asset replacement insights

While previous chapters have focused on the need for network augmentation, appropriate maintenance of Victoria's existing network asset base remains critical. In 2022, AEMO has again worked closely with AusNet Services to assess the need for the replacement, refurbishment, derating, or retirement of existing assets that are approaching end-of-life.

In the 2022 VAPR:

- AusNet Services' 2022 asset replacement and refurbishment plans are largely consistent with those presented in the 2021 VAPR.
- One new asset refurbishment project has been identified, or has now moved within the assessment horizon:
  - Hazelwood A2, A3, and A4 500/220 kV transformers refurbishment.
- AusNet Services has completed RIT-T assessments on four asset renewal projects and commenced RIT-T process for other projects where the PSCR or PADR have been published. This chapter includes an update on the status of these asset replacement RIT-T projects. The primary asset replacement projects for which AusNet Services has either commenced or completed the RIT-T assessment include:
  - 330 kV No. 1 and No. 2 tower upgrades between Murray (MSS) and Dederang Terminal Stations (DDTS).
  - 500 kV Gas Insulated Switchgear (GIS) replacement at Sydenham Terminal Station (SYTS).
  - Transformer and circuit breaker replacement at Shepperton Terminal Station (SHTS).
  - Static Var Compensator (SVC) replacement at Horsham Terminal Station (HOTS).
  - Circuit breaker replacement at Moorabool Terminal Station (MLTS).
  - Conductor and ground wire replacement.
  - Transmission line insulator replacement program.
- For a subset of replacement projects selected jointly by AusNet Services and AVP, AVP has analysed future system needs and confirmed the underlying system impact that would arise if the existing asset was removed without replacement. This analysis identified continuing system needs associating with most of the selected asset replacement projects.

5.1 Rule requirements

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 these assets.

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

Under NER clause 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[97].

Under NER clause 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.

5.2 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 justifies a RIT-T 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 projects, projects for which RIT-Ts have been completed, and projects associated with transmission assets that do not form part of the DSN were excluded from the network need assessment.
- 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 as long as the associated primary network components are still in service. As there is no committed retirement of Victorian transmission lines and Victorian interconnectors at present, AVP and AusNet Services agreed that all the nonelectrical assets which are associated with the Victorian transmission lines and interconnectors are still needed, without carrying out need assessment on individual projects involving secondary equipment.

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

- 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 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.

5.3 Needs assessment results

Table 21 presents the summarised findings from the assets needs assessment.

Table 21 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	8	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.
Keilor Terminal Station A4 500/220kV Transformer Replacement	Keilor Terminal Station	71	2027	Keilor A2/A3 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	2028	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] In the short term prior to the pending retirement of Yallourn Power, a reduction in capacity of the HWTS 500/220kV transformation may not have material impact on the network performance due to expected low load flow on the transformation. Refer to the Project "Hazelwood Terminal Station A2, A3 and A4 Transformer Replacement for long term need of these transformers

[99] AusNet Services and AEMO will continuously work together to determine the preferred option in replacing the existing Keilor transformers.

[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. 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) has 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.

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	2028	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	2028	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 220 kV GIS	Newport Power Station Switchyard	43	2029	Newport – Brooklyn 220 kV line Newport – Fishermans Bend-220 kV line	Loss connection to Newport generation.
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.

101 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. 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) has 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.

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 Replacement	Hazelwood Terminal Station	45	2030	HWTS A2, A3 and A4 500/220 kV transformers	Reduced reliability and capability to supply Melbourne eastern metro load.[102]
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 emergency fire services.
Yallourn Power Station 220kV Circuit Breaker Replacement Stage 2	Yallourn Power Station	10	2030	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.[103]
Wodonga Terminal Station 330kV and 66kV Circuit Breaker Replacement	Wodonga Terminal Station	13	2030	Wodonga – Dederang 330 kV line Wodonga – Jindera 330 kV line	Reduced Victoria DSN capacity and Vic – NSW interconnector capabilities.

[102] The need for Hazelwood A2, A3, and A4 transformers is dependent on future generation market dispatch in the Latrobe Valley or further east. Hazelwood transformation allows continued utilisation of Latrobe Valley to Melbourne 220 kV lines to supply Melbourne eastern metro load. Major generation connection at Hazelwood may require Hazelwood transformation to connect to the 500 kV network any portion of this generation not transmitted to Melbourne at 220 kV.

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

5.4 Asset renewal Regulatory Investment Test projects

AusNet Services completed RIT-Ts for the following asset renewal projects since publication of the 2021 VAPR:

- SYTS 500 kV GIS Replacement.
- SHTS Transformer and Circuit Breaker Replacement.
- Voltage Control in North West Victoria (HOTS SVC Replacement Project).
- Maintain reliable transmission network services at Moorabool Terminal Station (MLTS 500 kV and 220 kV Circuit Breaker Replacement Project).

AusNet Services is progressing a number of DSN asset renewal project RIT-Ts on both primary and secondary assets and provided the following updates to these RIT-Ts.

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

The transmission towers along the Murray to Dederang transmission lines (MSS-DDTS) were built from 1959 to 1965 using 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 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, which include the *Electricity Safety Act 1998*.

AusNet Services published the PSCR in April 2022[104] and expect to publish the PACR in November 2022.

5.4.2 Conductor and ground wire replacement

AusNet Services commenced this RIT-T to identify the preferred option to replace aging conductors and ground wires. 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 conductor or ground wire failures.
- Ensure that it complies with its regulatory obligations, which include the *Electricity Safety Act 1998.*

AusNet Services published the PSCR in April 2022[105] and expect to publish the PACR in November 2022.

5.4.3 South West Network Communications replacement

The protection, control, Supervisory Control and Data Acquisition (SCADA) and operational communications for the South Western Victoria Transmission network and interconnection to South Australia is currently enabled by

[104] 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.

[105] See Conductor & Ground Wire Replacement PSCR.

communication assets known as SDH/PDH (Synchronous Digital Hierarchy / Plesiochronous Digital Hierarchy) and 5-hop microwaves. The SDH/PDH asset currently serves the following lines in the South Western Region of Victoria:

- 220 kV lines from Moorabool to Terang.
- 220 kV lines from Ballarat to Terang.
- 500 kV lines from Moorabool to Heywood.
- 500 kV lines from Heywood to the aluminium smelter at Portland.

The assets have been in service for an extended time and the condition of the SDH/PDH equipment has deteriorated to a level where there is a material risk of asset failure. Asset failure could reduce electricity transmission reliability, impact safety, the environment, and require emergency asset replacements. Also, the SDH/PDH technology has served the business for over 35 years and is now considered a legacy technology.

AusNet Services commenced a RIT-T to identify the preferred option to replace SDH/PDH technology, to maintain the required reliability of the transmission network services for the South Western Victoria Transmission network and provide a communications network with a scalable solution that meets the REZ bandwidth requirements.

AusNet Services published the PSCR in May 2022 and expect to publish the PACR in October 2022.

5.4.4 Transmission Line Insulator Replacement Program

AusNet Services commenced a RIT-T to identify the preferred option to replace some 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, which include the *Electricity Safety Act 1998.*

AusNet Services published the PSCR in June 2022 and expects to publish the PACR in November 2022.

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[106].

[106] See https://www.ausnetservices.com.au/en/About/Projects-and-Innovation/Regulatory-Investment-Test.

A1. Distribution network service provider planning

This appendix lists the preferred connection modifications from the 2021 Transmission Connection Planning Report[107] and the potential DSN impacts and considerations.

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 around 2026.	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 2024-25, subject to RIT-T underway.	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 2027.	Increased demand requiring this transformer will be included in Greater Melbourne and Geelong planning.
Terang 66 kV	Install a third Terang 150 MVA 220/66 kV transformer by around 2027. A RIT-T will commence in 2025-26.	Increased demand requiring this transformer will be included in South West Victoria 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 Vitoria planning.

[107] See https://jemena.com.au/documents/electricity/2021-tcpr.aspx.

A2. DSN limitation detail

Transmission network limitations are grouped geographically.

The changes in the list of limitations are:

- New:
  - Additional trigger of generator planting and retirements as per the 2022 ISP Step Change scenario for several limitations.
- Change in category:
  - The following are now categorised as emerging limitations, as outlined in Section 4.2:
    - Minimum fault level requirements at Thomastown, Moorabool and Hazelwood fault level nodes.
    - High voltages in Metropolitan Melbourne and South West Victoria.
    - Metropolitan Melbourne area voltage stability.
  - The following are now categorised as developing limitations, as outlined in Section 4.4:
    - Overload of Geelong – Deer Park – Keilor 220 kV lines.
    - Insufficient reactive support at Deer Park.
  - The following are now categorised as monitored limitations:
    - Overload of Ballarat – Berrybank – Terang – Moorabool 220 kV line.
    - Overload of the Murra Warra – Horsham – Bulgana 220 kV line.
    - Voltage instability/collapse around Wemen Terminal Station.
    - Overload of Red Cliffs – Wemen – Kerang – Bendigo 220 kV line.
    - Overload of Dederang – Glenrowan – Shepparton – Bendigo 220 kV line.
    - Overload of Moorabool 500/220 kV transformer.
    - Voltage collapse limitation in South West Victoria
    - Voltage oscillation in western and north-western Victoria during prior outage conditions.
- 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.

A2.1 Central North REZ

Table 22 Limitations in the Central North REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 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	The new transformer or new transmission lines are likely to be contestable projects.

A2.2 Eastern Corridor

Table 23 Limitations in the Eastern Corridor

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Hazelwood – Yallourn 220 kV line loading	Developing	• Construct a new single circuit Hazelwood – Yallourn 220 kV line. • Construct a new double circuit Hazelwood – Yallourn 220 kV line and string only one circuit. • Construct a new double circuit Hazelwood – Yallourn 220 kV line and string both circuits. • Rebuild existing double circuit Hazelwood – Yallourn 220 kV line to a higher rating. • Installation of BESS on the 220 kV network east of this constraint.	Post Yallourn Power Station retirement if the Latrobe Valley is operated in a parallel configuration and additional generation	Not identified	The new line is likely to be a contestable project. The line upgrade is unlikely to be a contestable project.
Hazelwood – Rowville 220 kV line loading	Monitored	• Construct a new single circuit Hazelwood – Rowville 220 kV line.	Post Yallourn Power Station retirement if the Latrobe Valley is operated in a parallel configuration	Not identified	The new line is likely to be a contestable project

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
		• Construct a new double circuit Hazelwood – Rowville 220 kV line and string only one circuit. • Construct a new double circuit Hazelwood – Rowville 220 kV line and string both circuits.	and additional generation is commissioned on the 220 kV network at HWPS, at a site east of HWPS or on the 500 kV network east of CBTS.		
Rowville – Yallourn 220 kV line loading	Monitored	• Construct a new single circuit Rowville – Yallourn 220 kV line. • Construct a new double circuit Rowville – Yallourn 220 kV line and string only one circuit. • Construct a new double circuit Rowville – Yallourn 220 kV line and string both circuits.	Post Yallourn Power Station retirement if the Latrobe Valley is operated in a parallel configuration and additional generation is commissioned on the 220 kV network at HWPS, at a site east of HWPS or on the 500 kV network east of CBTS.	Not identified	The new line is likely to be a contestable project
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	The new line is likely to be competitively sourced
Rowville – Yallourn 220 kV line loading	Monitored	• Upgrade the 220 kV Hazelwood – Rowville or Yallourn – Rowville lines.	During period of extremely high temperature and high output from Yallourn Power Station.	Not identified as a material limitation in the scenarios modelled.	The line upgrade is unlikely to be a contestable project.
System strength shortfall at Hazelwood	Emerging	• Installation of a synchronous condenser. • Installation of grid forming BESS.	Retirement of synchronous generators.	Identified in 2020 ISP	This is likely to be a contestable project
Hazelwood – Loy Yang 500 kV line outage	Developing	• 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.	Lack of outage window period due to constricted maximum and minimum demand threshold post Yallourn Power Station retirement.	Not identified	The new line is likely to be competitively sourced

A2.3 Northern Corridor

Table 24 Limitations in the Northern Corridor

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 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	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.	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.	The 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.	These are both likely to be contestable projects
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	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.	These are both likely to be contestable projects.

A2.4 Murray River REZ

Table 25 Limitations in the Murray River REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Voltage oscillation in western and north-west Victoria (under prior outage)	Monitored	• NMAS contracts to provide system strength. • Install an automatic generation runback control scheme.	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.	These are likely to be contestable projects.
Red Cliffs – Wemen – Kerang – Bendigo 220 kV line (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	These 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.	These are both likely to be contestable projects
Red Cliffs – Wemen – Kerang – Bendigo 220 kV line (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.	These are likely to be contestable projects.

A2.5 South West Victoria REZ

Table 26 Limitations in the South West Victoria REZ

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Ballarat – Berrybank – Terang –	Monitored	• Install an automatic generation runback control scheme.	Increased generation in regional Victoria	Identified as limitation as part of South West Victoria REZ.	These are likely to be contestable projects.

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Moorabool 220 kV line		• Replace the existing Ballarat – Berrybank – Terang – Moorabool 220 kV line with a new double circuit 220 kV circuit line.			
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/2021 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.	The 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.	The new transformer is likely to be a contestable project.
High ROCOF in south-west Victoria	Developing	• Install a post-contingent generation tripping control scheme to control ROCOF during a period when one of the 500 kV lines west of Moorabool is out of service.	Increased probability of prior outages of 500 kV transmission line west of Moorabool. Increased generation connected to the 500 kV lines west of Moorabool.	Not identified as it is a localised issue	The control scheme implementation 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	Increased generation on the MLTS – HYTS lines and high import from South Australia.	Not identified.	To be confirmed

A2.6 Greater Melbourne and Geelong

Table 27 Limitations in Greater Melbourne and Geelong

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Ringwood – Thomastown and 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.	Increased demand in Eastern Metropolitan Melbourne and/or Latrobe Valley operated in radial configuration after Yallourn Power Station retirement	Not identified as it is a localised issue	The line cut-in is unlikely to be a contestable project
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	The 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	The third circuit is likely to be a contestable project
Rowville A1 500/220 kV transformer loading	Developing	• Install a second 500/220 kV 1,000 MVA transformer at Cranbourne.	Increased demand in Eastern Metropolitan Melbourne and/or Latrobe Valley operated in a radial configuration after Yallourn Power Station retirement. Generation planting and retirements as per the 2022 ISP *Step Change* scenario – subject to Latrobe Valley configurations.	Not identified as a material limitation in the scenarios modelled.	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 and/or Latrobe Valley operated in a radial configuration after Yallourn Power Station retirement.	Not identified as a material limitation in the scenarios modelled.	This is unlikely to be a contestable project

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Cranbourne A1 500/220 kV transformer loading	Developing	• Install a new 500/220 kV transformer at Cranbourne Terminal Station.	Increased demand around the Eastern Melbourne Metropolitan area and/or Latrobe Valley operated in a radial configuration after Yallourn Power Station retirement. Generation planting and retirements as per the 2022 ISP Step Change scenario – subject to Latrobe Valley configurations.	Not identified as a material limitation in the scenarios modelled.	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. • Install a third 500/220 kV transformer at Rowville, plus any fault level mitigation works.	Increased demand around the Melbourne Metropolitan area and/or increased export to New South Wales and/or Latrobe Valley operated in a radial configuration after Yallourn Power Station retirement. Generation planting and retirements as per the 2022 ISP Step Change scenario.	Not identified as it is a localised issue.	The new transformer is likely to be a contestable project.
Moorabool – Geelong - Keilor 220 kV line loading	Developing	• Connect a new double circuit Moorabool – Geelong 220kV line with a rating of approximately 800 MVA at 35ºC. • 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.	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.	Not identified as a material limitation in the scenarios modelled.	This is likely to be a contestable project.
Keilor – Deer Park – Geelong 220 kV line loading	Developing	• Installing a load shedding control scheme • Replace the existing Geelong – Keilor No. 1 and No. 3 220 kV lines with a new double circuit line rated at 800 MVA at 35ºC. • Parallel the existing three Geelong – Deer Park – Keilor 220 kV circuits to form a Geelong – Deer Park and Deer Park – Keilor circuit, each rated 810 MVA at 35º C.	Increased demand at Deer Park.	Not identified as a material limitation in the scenarios modelled.	These are unlikely to be contestable projects.

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Keilor – Thomastown No. 1 220 kV line	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 transformer at Rowville, plus any fault level mitigation works.	Latrobe Valley operated in a radial configuration after Yallourn Power Station retirement	Not identified as it is a localised issue.	The new transformer is likely to be a contestable project.
Insufficient reactive support at Deer Park Terminal Station	Developing	• Install capacitors • Install an SVC or STATCOM. • Utilise reactive power support from any future battery energy systems	Increased load at Deer Park terminal station.	Not identified as it is a localised issue.	These are likely to be contestable projects.
Sydenham – Keilor 500 kV line	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.
Melbourne Metropolitan Area voltage stability	Emerging	• Install additional capacitors at strategic locations. • An SVC or a STATCOM.	Increased maximum demand in the Melbourne Metropolitan area	Not identified as a material limitation in the scenarios modelled	These are likely to be contestable projects
Insufficient reactive support in Melbourne Metropolitan and south-west transmission corridor	Emerging	• Additional reactors. • Installation of a synchronous condensers. • An SVC or a STATCOM.	Decreased minimum demand in Melbourne metropolitan area.	Identified in 2019 NSCAS.	These are likely to be contestable projects
System strength shortfall at Thomastown	Emerging	• Installation of a synchronous condenser. • Installation of grid forming BESS	Retirement of synchronous generators	Identified in 2020 ISP	This is likely to be a contestable project.
System strength shortfall at Moorabool	Emerging	• Installation of a synchronous condenser. • Installation of grid forming BESS	Retirement of synchronous generators	Identified in 2022 ISP	This is likely to be a contestable project.

* This monitored limitation assumes 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.

A2.7 Western Victoria REZ

Table 28 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 an automatic generation runback control scheme. • 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.

A2.8 Victoria system-wide

Table 29 Limitations in the Victorian system

Limitation	Limitation type	Possible network solution	Trigger	2022 ISP / 2021 NSCAS	Contestable project status
Insufficient demand to maintain minimum synchronous requirement	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.

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 unserved energy (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 *Inputs, Assumptions and Scenarios Report* (IASR) wherever possible. Key assumptions and inputs include:

- The 10% probability of exceedance (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[108].

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

A4. Latrobe Valley DSN configuration

Currently, the Latrobe Valley DSN is usually operated with 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 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).

Alternative to the radial mode, there are a number of other possible Latrobe Valley DSN configurations, with the most common alternative mode called parallel mode, where generation from power stations within the Latrobe Valley is sent out of the Latrobe Valley using both the 500 kV network and 220 kV network.

Figure 37 and Figure 38 demonstrate the DSN in the radial mode and the parallel mode.

The Latrobe Valley DSN configuration might need to be changed following the retirement of Yallourn Power Station and Loy Yang, as the currently system normal mode (radial mode) may no longer be effective. Without generation from Yallourn and any new generation connected to the 220 kV network between HWTS and ROTS (via Yallourn), the existing HWTS-YPS, HWTS- ROTS and YPS-ROTS 220 kV lines will no longer transfer Latrobe Valley generation to Melbourne with the radial mode and therefore post Yallourn retirement, the most likely system normal mode will be parallel mode or its variation, depending on future changes to the Latrobe Valley DSN. AVP will continue to explore effective configuration options to identify the optimal configuration post Yallourn retirement for system normal and outage condition.

Figure 37 Latrobe Valley in radial mode

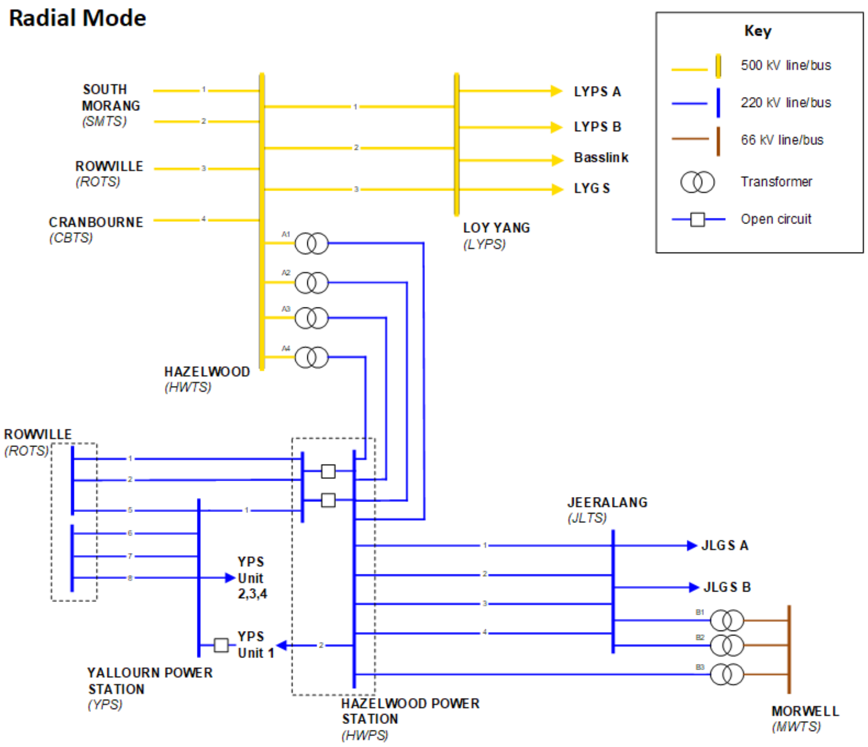
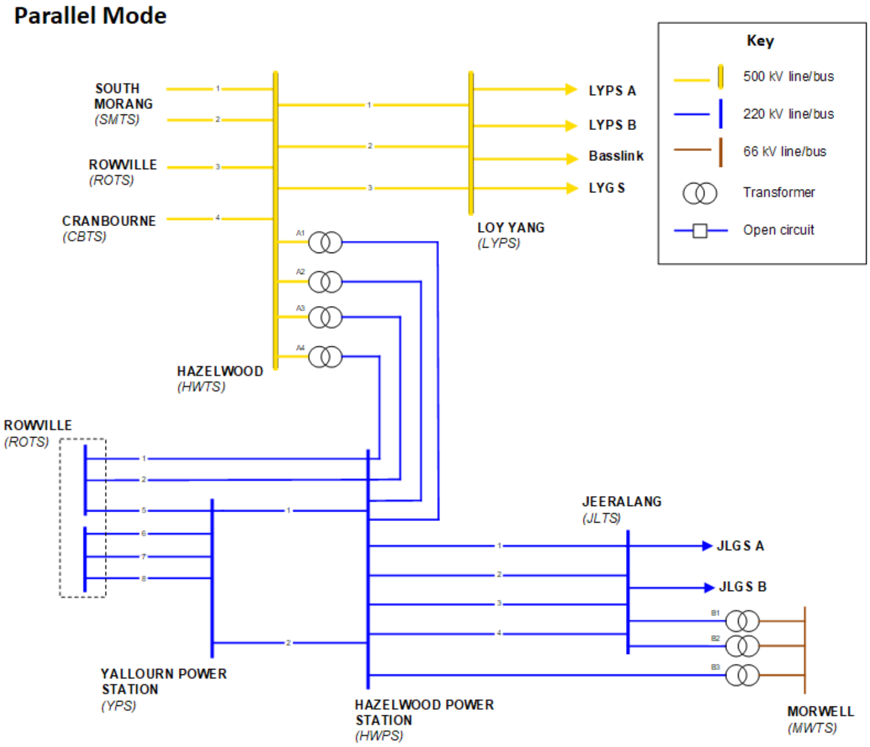


Figure 38 Latrobe Valley in parallel mode



A5. Network snapshots

Table 30 and Table 31 below outline the regional breakdown of load and generation at the times of maximum, minimum, and minimum night time demand in 2021 - 22.

Table 30 Regional breakdown of generation in each demand snapshot

Region	Maximum demand	Minimum demand	Minimum night-time demand
Greater Melbourne and Geelong	680 MW	98 MW	57 MW
V1 Ovens Murray	985 MW	0 MW	0 MW
V2 Murray River	127 MW	219 MW	1 MW
V3 Western Victoria	510 MW	12 MW	625 MW
V4 South West Victoria	513 MW	201 MW	492 MW
V5 Gippsland	4,670 MW	2,500 MW	3,105 MW
V6 Central North	64 MW	298 MW	0 MW

Table 31 Regional breakdown of load in each demand snapshot

Region	Maximum demand	Minimum demand	Minimum night-time demand
Greater Melbourne and Geelong	6,072 MW	1,421 MW	1,926 MW
V1 Ovens Murray	75 MW	3 MW	31 MW
V2 Murray River	216 MW	80 MW	138 MW
V3 Western Victoria	393 MW	38 MW	112 MW
V4 South West Victoria	556 MW	491 MW	536 MW
V5 Gippsland	656 MW	269 MW	467 MW
V6 Central North	300 MW	20 MW	132 MW

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
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

Abbreviation	Term in full
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