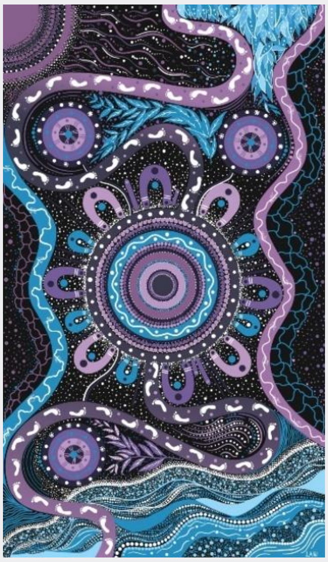
Victorian Network Performance & Insights Report

October 2024

A review of the Victorian Declared Shared Network (DSN)



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

This report has been published as a supporting document of 2024 Victorian Annual Planning Report (VAPR). The purpose of this report is to provide an overview of the performance of the Victorian Declared Shared Network (DSN) and its key insights during the period of financial year 2023-24. It provides a review of the historical performance of the DSN assessing the adequacy of the present-day network and forms a part of the Annual Planning Review process.

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1 Introduction

This section outlines the purpose and the summary of the content in this *Victorian Network Performance and Insights Report*, including the operational context in which the report has been prepared.

The *Victorian Network Performance and Insights Report* analyses the key performance indicators of the Declared Shared Network (DSN) over the period between 1 July 2023 and 30 June 2024. It assesses adequacy of the DSN based on its performance under various operating conditions identified during the 2023-24 financial year.

Reviewing the historical performance of the network can offer valuable insights by offering a data-driven foundation for informed decision-making that benefits Victorian energy consumers and planning outcomes. As such, the *Victorian Network Performance and Insights Report* is a fact-focused historical report which:

- Provides insights into the performance and capability of the DSN.
- Identifies the constraints in the present day DSN.
- Provides inputs to undertake annual planning review.

1.1 Purpose

The purpose of this report is to review and provide useful information to key stakeholders about the present-day network, to understand the DSN's effectiveness in supplying electricity to the Victorian energy consumers reliably and securely. Analysing past performance and trends helps identify future trends, predict future challenges and opportunities, and help guide informed investment decisions, minimising risk and increasing the likelihood of successful network operations.

In addition, the insights contained in this document lay context and groundwork for AEMO Victorian Planning (AVP), as key planning inputs and assumptions for AVP to undertake the Planning Studies as part of its Annual Planning Review under National Electricity Rules (NER) 5.12.1.

The review has been carried out in light of the NER, so the criteria will be limited to any requirements stipulated specifically for the DSN (such as network performance criteria in NER 5.1) or any other existing issues in the DSN that are relevant to the Development Plan.

1.2 Scope and structure

The scope of the analysis and the content presented in this report is based on the operational context of the DSN over the last financial year, primarily focused on existing network constraints and analysis of network operation during stressed operating conditions.

In evaluating the adequacy of the Victorian DSN, AVP has considered three broad areas, with indicators listed under each:

- **Operational observations (Section 2)** – provides key observations on managing the DSN within the technical envelope under system normal conditions and post-contingent situations.
  - Power system reviewable incidents: reviewable operating incidents[1] or other significant incidents which resulted in system security violations or loss of customer load or generation (Section 2.1).
  - Supply adequacy: analyses the ability of the DSN power system to meet consumer demand (Section 2.2).
  - Operational management: how network operation was impacted by the changing technical characteristics and geography of supply, particularly where such changes increased operational complexity (Section 2.3).
- **Review of network constraints (Section 3)** – an analysis of the most critical network constraints and the performance of the interconnectors and a comparison of them with the past years.
  - Impact of top binding constraint equations: the severity of network constraints (Section 3.1).
  - Interconnector capability: the extent to which the operational and design limits of interconnectors restricted the import and export of generation (Section 3.2).
- **Network behaviour assessment under stress (Section 4):**
  - Behaviour of the transmission network at time of high network stress: a range of case studies examining the performance of the network under highly stressed operating conditions.

1.3 Definitions

Unless otherwise stated:

- **Generation** is defined as all scheduled, semi-scheduled, and non-scheduled generation greater than 5 megawatts (MW) and does not include distributed photovoltaic (PV) systems.
- **Operational demand[2] and consumption** are 'as generated', meaning they include generator auxiliary loads[3].
- **Distributed PV** refers to PV systems up to 100 kilowatts (kW) capacity.

[1] For the full definition of "reviewable operating incident", see NER 4.8.15. 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.

[2] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/operational-demand-data.

[3] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Demand-Forecasts/Operational-Consumption-definition.pdf.

1.4 Preview

Victoria continues to attract investment in both distributed and large-scale variable renewable energy (VRE) resources, which is changing the supply-demand pattern across the state. Traditional load centres are now developing into supply hubs, while consumer energy resources (CER) are shifting the consumer load profile. With forecast increases in distributed PV storage, electric heating, electric vehicles (EVs) and data centres, this trend is expected to gather pace and require greater operational management and DSN investment to maintain reliability and system security. To adapt to these ongoing changes in the energy landscape, AVP is proactively engaging with distribution network service providers (DNSPs) and undertaking joint planning to develop holistic solutions.

Maintaining system strength in Victoria

Due to the growth of inverter-based resources (IBR)-based generation and the upcoming retirement of conventional generation units, network outage management becomes more challenging due to reduced maximum supportable demand and system strength shortfalls. Planning network outages, which will reduce system strength, is becoming increasingly difficult with a reduced number of baseload units available. Managing power system security during high renewable generation periods and planned and unplanned outages, especially in north-west Victoria, is currently causing network congestion in the West Murray region under prior outage conditions, and during forced outages a minimum number of synchronous generators are required to be online in both Victoria and South Australia.

As the System Strength Service Provider (SSSP) for Victoria, AVP is undertaking a system strength regulatory investment test for transmission (RIT-T), which will procure sufficient system strength even under credible outages and key contingencies[4].

Growing consumer energy resources (CER)

Increasing CER, including distributed PV penetration, is impacting the load blocks available for shedding and system restart. Voltage and frequency control also become increasingly difficult with increasing magnitude and duration of reverse power flows.

The national CER Roadmap sets a range of initiatives that will support integration and help ensure all consumers can continue to benefit from these resources[5]. Both short-term and long-term actions are needed, particularly to address periods when high distributed PV relative to underlying demand results in minimum operational demand levels where action may be required to maintain power system security.

Increasing maximum and reducing minimum demand

VRE resources are mostly located in regional and remote areas in Victoria. Transmission lines supporting the generation flow towards load centres are incapable of meeting the growing loads and need upgrades. Victoria is

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

[5] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf.

observing an increasing trend in maximum operational demand, where distributed generation (distributed PV) often offsets the daytime maximum underlying demand.

Historically, voltage control during low demand periods required frequent operator interventions in both the 500 kilovolts (kV) and 220 kV networks. Reliance on voltage control interventions results in higher market costs, reduced system resilience, and higher system security risks. The new reactors at Keilor Terminal Station (KTS) and Moorabool Terminal Station (MLTS) have significantly reduced the requirement for operational intervention to manage high voltages in Victoria but did not eliminate this operational challenge entirely in the past year and some voltage management interventions were required throughout 2023-24.

To be able to navigate the network changes to enable the growth in VRE and keep managing the operational challenges discussed above, coordinated timely investment is required. The *Victorian Annual Planning Report* (VAPR) provides more information about AVP's Transmission Development Plan[6].

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

2 Operational observations

This section examines the key operational aspects of the Victorian DSN during FY 2023-24 including:

- Reviewable incidents as defined by NER 4.18.5.
- The Victorian DSN's ability to meet customer demand.
- The current DSN's operational management measures.

Notable operational observations are:

- Peak demand – the annual peak Victorian operational demand in 2023-24 was **9,294 MW on 22 February 2024**, compared to 8,988 MW in 2022-23. Summer operational maximum demand increased from last year, but remained relatively low, driven by mild weather conditions, and increasing uptake of distributed PV.
- Minimum demand – Victoria recorded its all-time lowest minimum operational demand of **1,564 MW on 31 December 2023**. This was 631 MW lower than the previous record set last financial year. Minimum demand has occurred during the daytime because of the effect of distributed PV generation. On this day, above 3 gigawatts (GW) of distributed PV generation were observed. Large-scale solar generation in Victoria was curtailed due to some network constraints on this day.
- Severe storm activity caused significant damage to, and resulted in the failure of, six 500 kilovolts (kV) towers on 13 February 2024. Approximately 2,690 MW of generation was lost, and 1,000 MW of load was shaken off in Victoria following the disturbance. Several directed load shedding or emergency reserves were dispatched through Reliability and Emergency Reserve Trader (RERT) on 13 February 2024.
- Reverse power flows through the connection points into the DSN continued to occur due to the growth in distributed generation (including distributed PV). In 2023-24, the total number of hours of reverse power flows held relatively steady compared to 2022-23. More co-ordinated approaches with the DNSPs will be required to manage the operational challenges caused by the reverse power flows.
- In 2023-24, of 32 terminal stations assessed, 28 terminal stations were found to be injecting reactive power for more than 10% of the year. The new reactors at KTS and MLTS have reduced, but not entirely eliminated, the need for operational intervention to manage the high voltages in the DSN.

2.1 Power system reviewable incidents

Table 1 summarises notable power system incidents in Victoria during 2023-24, and highlights issues in the Victorian DSN which may, in future, develop into investment needs. This section does not consider events which occurred primarily within the distribution network.

Table 1 Summary of notable power system incidents in Victoria 2023-24

Date	Incident	Consequence
29/06/2023 (included as not reported in 2023 VAPR)	Loss of supervisory control and data acquisition (SCADA) and line protection at KTS	• Trip and auto-reclosure of the Altona Terminal Station (ATS) – KTS 220 kV line leading to the unexpected trip of the Salt Creek Wind Farm (WF), reduced output from Mortlake South WF and Basslink commutation failure. • Trip of the incoming miniature circuit breakers (MCBs) of the KTS 48 volt (V) direct current (DC) supplies at KTS disconnecting all DC supplies to the KTS 220 kV and 66 kV communications equipment and causing the loss of all communications systems from KTS, including communications between KTS with AEMO and AusNet control rooms. For approximately 105 minutes, the power system was not operating in a secure state and the five KTS 220 kV lines remained connected with no primary or backup protections systems*.
09/07/2023	Trip of Mortlake Power Station – Blue Gum substation 500 kV line and operation of circuit breaker fail protection	• Trip of the Mortlake Power Station (MOPS) – Blue Gum Substation (BGS) 500 kV line and BGS A1 500/220 kV transformer, resulting in islanding of Dundonnell WF from 254 megawatts (MW). • Operation of circuit breaker fail (CBF) protection including the disconnection of the MOPS G11 500/20 kV transformer. • Approximately 379 MW of generation was tripped. In addition, Mortlake South Wind Farm reduced output by 60 MW over 22 seconds before returning to full output. • 19 MW of load was stopped operating at Alcoa Portland.
13/02/2024	Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines (preliminary report)	• Severe storm activity caused significant damage resulting in the failure of six 500 kV towers (three on each of the two 500 kV circuits). • Trip of the Moorabool (MLTS) – Sydenham (SYTS) No. 1 and No. 2 500 kV lines. • Trips of these 500 kV lines led to the subsequent disconnection of all four Loy Yang A generating units, Dundonnell WF and Yaloak South WF. • Approximately 2,690 MW of generation was lost, and 1,000 MW of load was shaken off in Victoria.

* See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/loss-of-scada-and-line-protection-at-keilor-terminal-station-on-29-june-2023.pdf.

29/06/2023 – Loss of SCADA and line protection at Keilor Terminal Station (KTS)

At approximately 1452 hrs on 29 June 2023[7], due to a fault on the Altona Terminal Station (ATS) – KTS 220 kV line near KTS, the ATS – KTS 220 kV line tripped and auto-reclosed. As only one circuit breaker (CB) at each of ATS and KTS is set to auto-reclose, the KTS 500/220 kV A2 transformer was offloaded at the 220 kV side and the ATS – Laverton North Gas Station (LNGS) 220 kV No. 1 line and LNGS No. 1 transformer were disconnected. Salt Creek Wind Farm (WF) tripped from 44 MW and Mortlake South WF reduced power output from 83 MW to 53 MW over 13 seconds and returned to 83 MW over the next 24 seconds.

Co-incident with the fault, the KTS 48 volts (V) direct current (DC) supplies to the A and B communications incoming miniature circuit breakers (MCBs) tripped. This removed all DC supplies to the KTS communications equipment and caused the loss of all communications systems from KTS. The loss of communications at KTS interrupted supervisory control and data acquisition (SCADA) to AEMO and AusNet, and interrupted communications between KTS and its connecting 220 kV and 66 kV substations. The communications disruption also resulted in the widespread loss of line differential protection and circuit breaker fail (CBF) signalling at KTS. For the duration of the communications outage, five 220 kV lines remained in operational service with no effective primary or backup protection systems. Due to the impact this incident had on primary and CBF protection

[7] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/loss-of-scada-and-line-protection-at-keilor-terminal-station-on-29-june-2023.pdf.

systems, AEMO has determined that the power system was not in a secure operating state for approximately 105 minutes.

On 3 October 2023 at 1205 hrs, AEMO issued a market notice[8] to advise the market that the reclassification of the trip of the ATS – KTS 220 kV line and the Salt Creek WF as a credible contingency had been removed from 1200 hrs 3 October 2023.

09/07/2023 – Trip of Mortlake Power Station (MOPS) – Blue Gum Substation (BGS) 500 kV Line

On 9 July 2023[9] at 0653 hrs, transmission equipment failed, leading to an internal flashover. This led to the trip of the MOPS – BGS 500 kV line and the BGS A1 500/220 kV transformer, resulting in approximately 379 MW of generation being tripped. Details of the loss of generation include:

- The islanding of Dundonnell WF, resulting in the loss of 254 MW of generation.
- A turbine parameter settings issue at Salt Creek WF, resulting in generation loss of 47 MW.
- A converter parameter issue impacting 24 turbines at Mt Mercer WF, resulting in a reduction in output of 48 MW.
- A converter timer fault impacting 15 turbines at Port Cape Nelson WF, reducing output by 30 MW.
- A settings issue causing a fault ride through at Mortlake South WF, reducing output by 60 MW over 22 seconds before returning to full output.
- 19 MW of load was curtailed at Alcoa Portland.

13/02/2024 – Trip of Moorabool Terminal Station (MLTS) – Sydenham Terminal Station (SYTS) 500 kV No. 1 and No. 2 lines

The trip of MLTS – SYTS 500 kV No. 1 and No. 2 lines on 13 February 2024[10] was classified as a non-credible event. At 1308 hrs on this day, a major storm rolled south from the north of Victoria, causing the destruction of six 500 kV towers (three on each of the two 500 kV circuits) and tripping the MLTS – SYTS No. 1 and 2 500 kV lines. The simultaneous trip of these 500 kV lines and subsequent disconnection of all four Loy Yang A generating units, Dundonell WF and Yaloak South WF had a significant impact on the Victorian power system.

Initial review indicates Dundonell WF tripped as designed due to operation of the Southwest 500 kV special control scheme to prevent instability, followed by disconnecting from Victorian network. At the time of this publication, AEMO's investigation is still ongoing into the other causes for the generation tripping.

In total, approximately 2,690 MW of generation was lost, and 1,000 MW of load was shed in Victoria following this event. **Figure 1** shows AEMO's initial review of the phasor measurement unit (PMU) data indicating there were

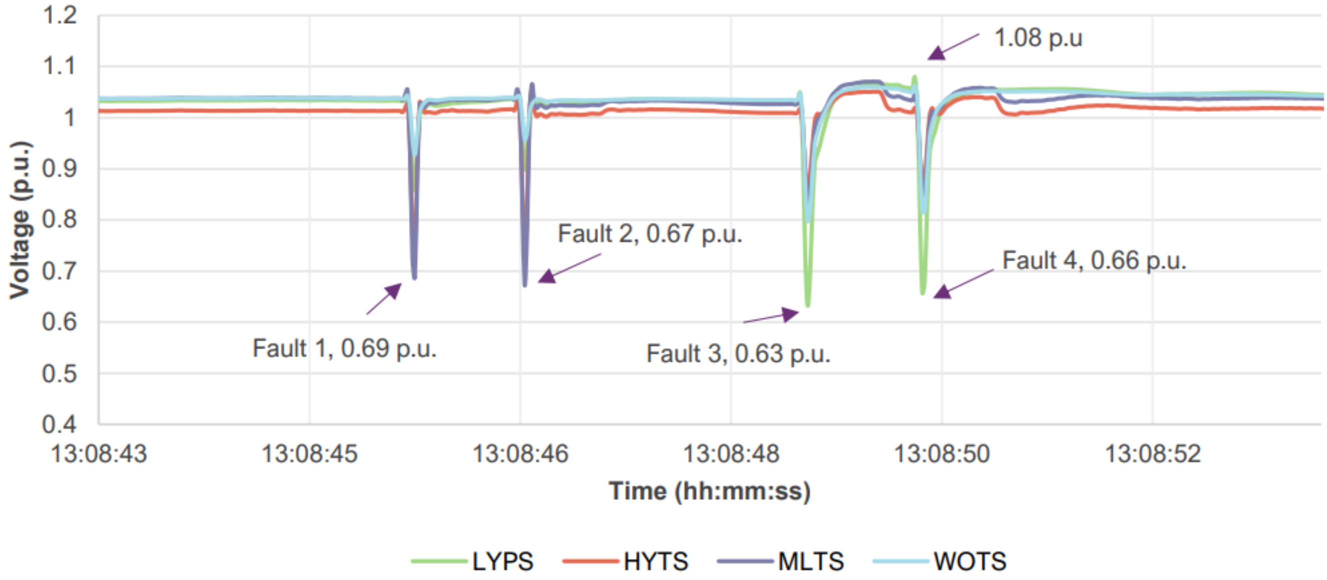
[8] AEMO generally informs the market about operating incidents as they progress by issuing Market Notices – see https://www.aemo.com.au/Market-Notices.

[9] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/trip-of-mops---bgs-500-kv-line-and-operation-of-circuit-breaker-fail-protection-on-9-july-2023.pdf.

[10] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf

four faults in Victoria, where the voltage depression was experienced throughout Victoria and was observed to be as low as 0.63 per unit (p.u.)[8], yet subsequently recovered up to an acceptable operating limit.

Figure 1 Positive sequence voltage throughout Victoria on 13 February 2024 (p.u.)



Following the event, at 1420 hrs on 13 February 2024, AusNet[11] was instructed to shed 300 MW of load to manage loading of in-service network elements. AEMO subsequently instructed load to be restored at 1450 hrs and 1510 hrs.

Later, at 1543 hrs on 13 February 2024, a further separate incident occurred involving trip of the Hazelwood Terminal Station (HWTS) – Jeeralang Terminal Station (JLTS) 220 kV No. 2 line and the offloading of the HWTS 500/220 kV No. 1, No. 2, No. 3 and No. 4 transformers. This incident is subject to an ongoing separate review.

Separate to the transmission system event, storm activity across Victoria caused significant damage to the distribution networks on Tuesday 13 February 2024, resulting in loss of supply to more than 500,000 residential and business customers.

2.2 Supply adequacy

The supply-demand balance in Victoria was maintained for all periods in 2023-24, except during the major storm event on 13 February 2024 discussed above. Victoria's strong interconnection with neighbouring regions plays a significant role in both Victoria's own supply adequacy and that of other regions.

[11] AusNet is the Victorian Declared Transmission System Network Operator.

During 2023-24, Victoria experienced one actual[12] Lack of Reserve (LOR)[13] on 13 February 2024. On this day, one LOR2 was forecast[14] and an actual LOR3 was declared. On 10 March 2024, one LOR1 was forecast in Victoria.

These LOR conditions were mainly driven by decreased generation availability and increased demand followed by unplanned transmission outages due to non-credible events, as described in Section 2.1. The actual LOR3 event was the result of the major incident on 13 February 2024 caused by storm activity. This incident had a significant impact on the Victorian power system, resulting in the issuing of short notice RERT in response to a forecast LOR2 conditions on the same day (see case study below).

Case study: Forecast LOR2 and actual LOR3 conditions on 13 February 2024

On 13 February 2024, AEMO activated 275 MW of RERT in Victoria in response to a forecast LOR2 condition. This forecast LOR2 incident was triggered by the trip of both MLTS – SYTS 500 kV lines in Victoria. The simultaneous trip of these 500 kV lines and subsequent disconnection of all four Loy Yang A generating units and some wind farms impacted the Victorian power system. Dundonnell WF tripped as designed due to operation of the Southwest 500 kV special control scheme. Following the trip, thermal limits on the 220 kV lines between Geelong Terminal Station (GTS) and MLTS were intermittently violating between dispatch intervals ending 1315 hrs to 1420 hrs.

Prior to the trip at 1305 hrs, Victoria had operational demand of 7,724 MW and 9,926 MW of total (scheduled, semi scheduled and distributed PV) generation. Generation was 2.2 GW higher than the operational demand. However, due to the constraints on the network, generation was not able to supply the load. RERT could not assist in relieving the constraints because the location of the RERT reserves was either not known or not in a suitable location.

To maintain the system in a secure operating state, an actual LOR3 condition was declared, where AEMO issued a direction to AusNet under NER 4.8.9 to shed 300 MW of load in the KTS, Thomastown Terminal Station, and Rowville Terminal Station, which all supply the Melbourne metropolitan area.

Soon after, AEMO issued another direction to AusNet to commence the load restoration, beginning with 150 MW at 1450 hrs and 150 MW at 1510 hrs. Following load restoration, at 1515 hrs the actual LOR3 was cancelled.

2.2.1 Victoria's maximum operational demand

Victoria reached its annual maximum operational demand of 9,294 MW on Thursday 22 February 2024 at 1600 hours. Similar to 2022-23, the maximum operational demand occurred in the late hours of the day, reflecting the increasing trend for distributed PV generation to meet a growing proportion of underlying demand during the day. **Figure 2** shows Victoria's maximum demand levels since 2000. Although demand increased compared to 2022-

[12] An actual LOR is when the market response to the forecast LOR has not been adequate to clear the LOR thresholds, and the LOR becomes an operational reality. See https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf.

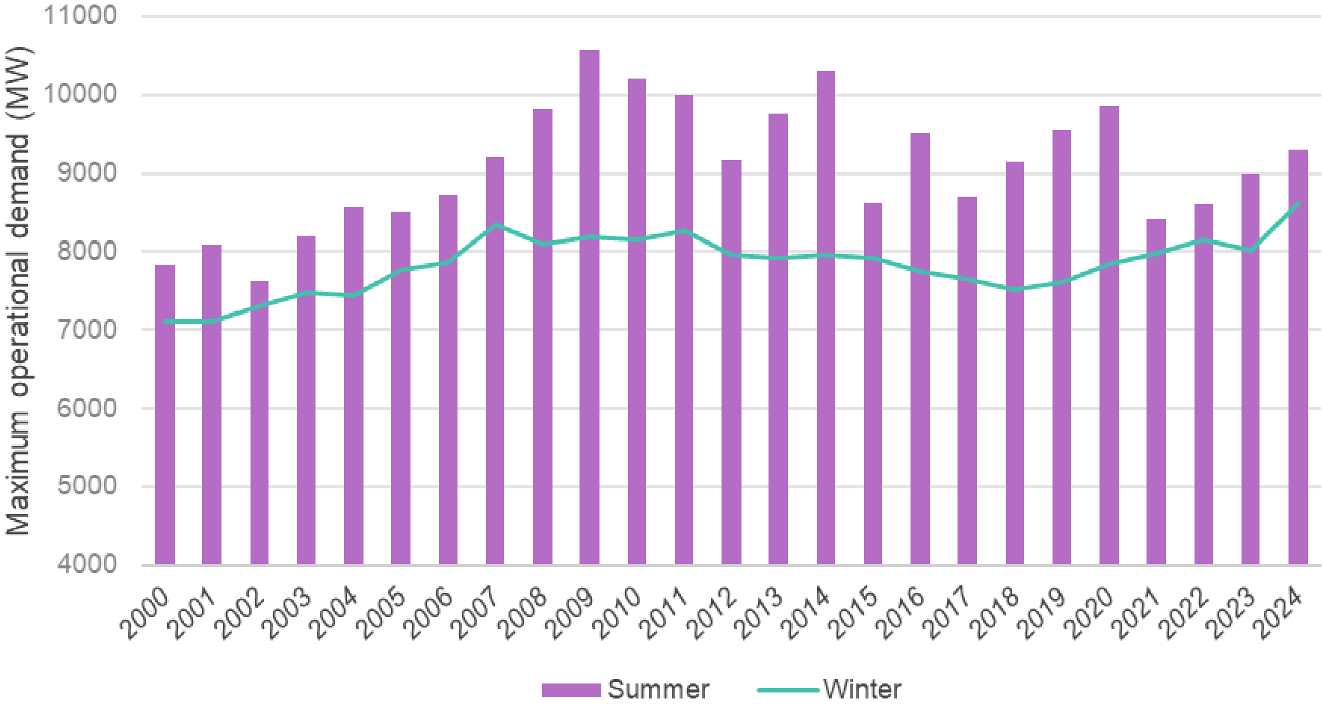
[13] This condition exists when the available electricity supply is equal to or less than the operational demand. This means there are no reserve supplies available. See https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf.

[14] A forecast LOR occurs when AEMO's forecasts show a reduced amount of electricity reserves. See https://aemo.com.au/-/media/files/learn/fact-sheets/lor-fact-sheet.pdf.

23, when the maximum reached 8,988 MW, milder summer temperatures saw the Victorian maximum operational demand remain relatively low compared to 9,852 MW in 2019-20 and 10,313 MW in 2013-14.

Victoria's maximum winter operational demand peaked at 8,612 MW on Monday 15 July 2024 at 1800 hours[15]. The elevated winter maximum demand compared to previous years is likely a result of colder winters increasing the use of heating. From an operational perspective, this trend will not pose as a challenge, as there are fewer thermal constraints in winter than in summer.

Figure 2 Actual maximum summer and winter Victorian operational demand from 2000 to 2024 (MW)



2.2.2 Victoria's minimum operational demand

Victoria recorded its all-time lowest minimum operational demand of 1,564 MW on Sunday 31 December 2023 at 1300 hrs[16]. This was 631 MW lower than the previous record set last financial year[17].

The impacts of distributed PV on this day are shown in **Figure 3**; distributed PV generation met 66% of Victoria's estimated underlying demand, the highest on record and an increase of 11% compared to 2022-23. Without the effect of distributed PV generation, minimum demand on this day would have occurred at 0400 hours at 3,543 MW.

[15] Analysis period has been extended to August 2024 to capture maximum winter demand.

[16] See Page 10 at https://aemo.com.au/-/media/files/major-publications/qed/2023/quarterly-energy-dynamics-q4-2023.pdf.

[17] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2023/2023-victorian-annual-planning-report.pdf.

Figure 3 Victorian demand profile and impact of distributed PV on the day of minimum demand, 31 December 2023 (MW)

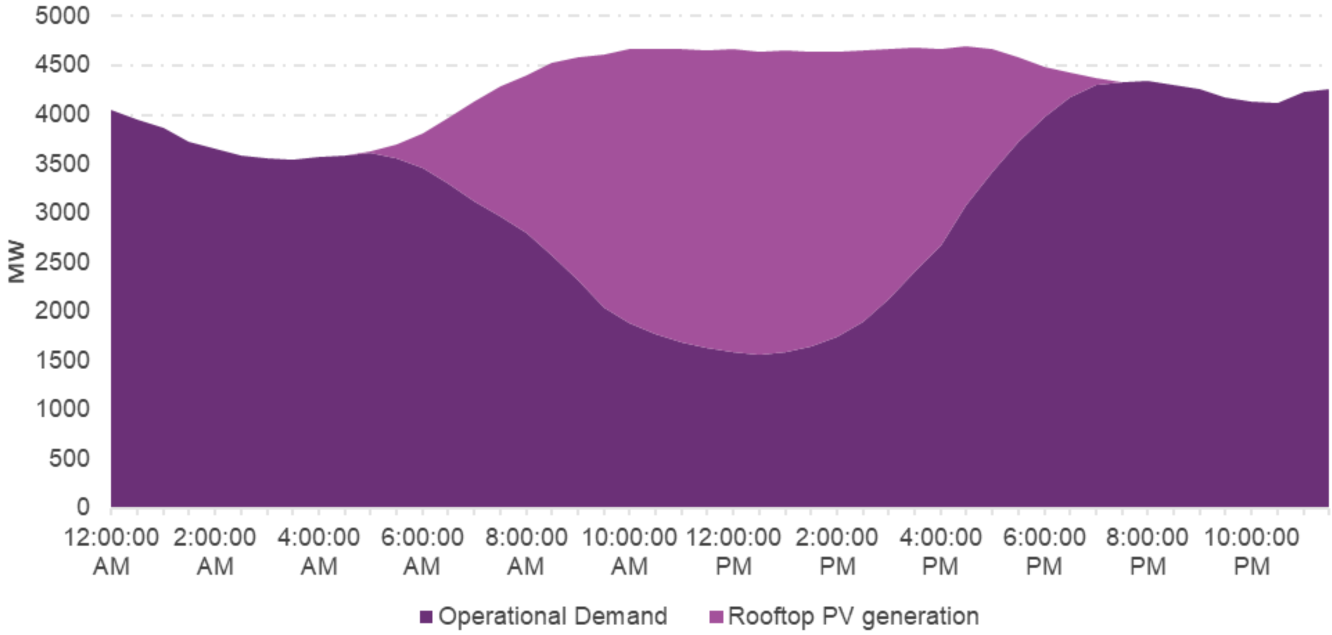
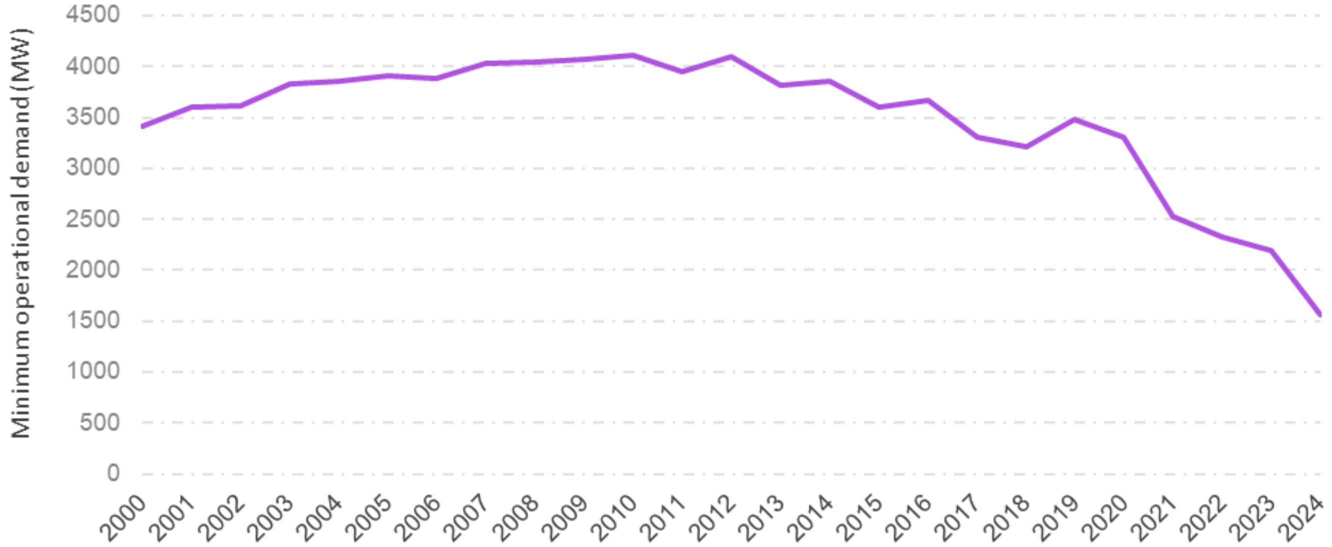


Figure 4 shows that minimum operational demand continued its downward trend, with 2023-24 being the sixth consecutive year to record its annual minimum demand during the daytime.

Figure 4 Actual minimum Victorian operational demand, 2000 to 2024 (MW)



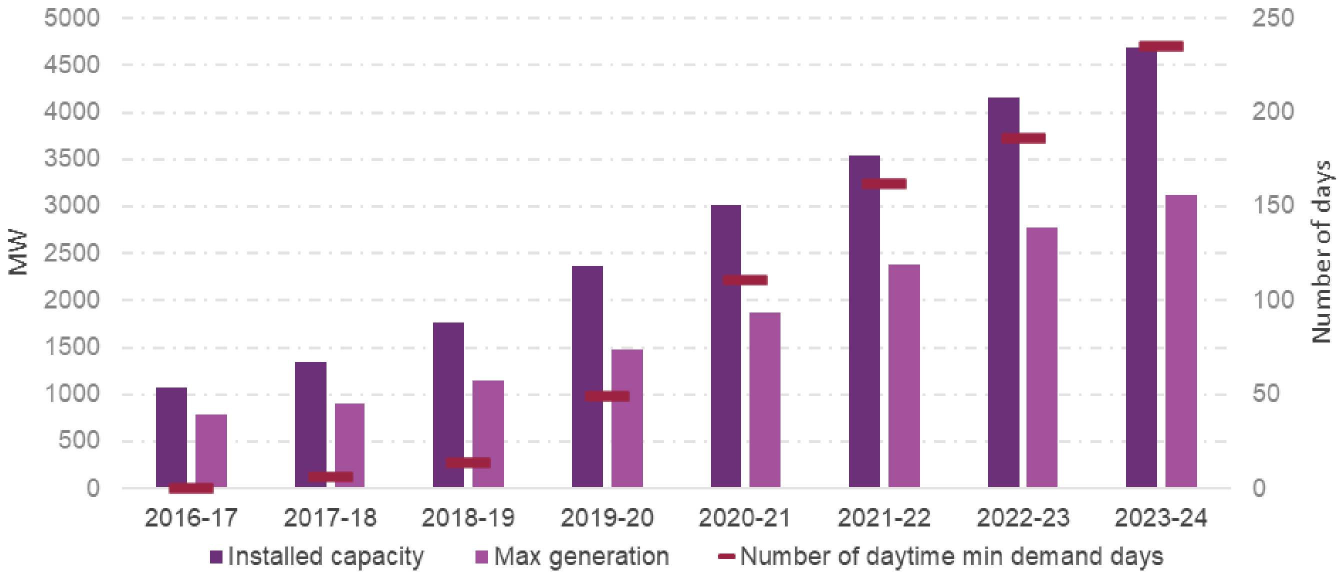
In Victoria, distributed PV continued to grow in terms of capacity and maximum generation, as shown in **Figure 5**. More than 525 MW of distributed PV was installed in Victoria over the 2023-24 financial year[18]. As the installed capacity of, and maximum generation from, distributed PV continue to grow, daily minimum demand is occurring

[18] 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.

during daylight hours (08:00 to 17:00) more frequently. This was the case on 235 days in 2023-24, compared to 186 days in 2022-23 and 162 days in 2021-22.

With this trend of frequent minimum demand during daylight hours, AVP anticipates frequent voltage management issues due to the excessive voltages primarily driven by lightly loaded transmission lines during high DER conditions and will consider these increases in minimum demand days in its voltage management planning.

Figure 5 Actual distributed PV capacity and maximum generation by financial year and number of daytime minimum demand days, 2016-17 to 2023-24 (MW)



2.2.3 Victorian supply

It is crucial to monitor generation sources and their impacts on the grid to ensure the balance of supply and demand and prevent power outages or overloads as Victoria transitions to renewable resources. This section will cover key observations about Victorian generators over the past year.

Coal generation

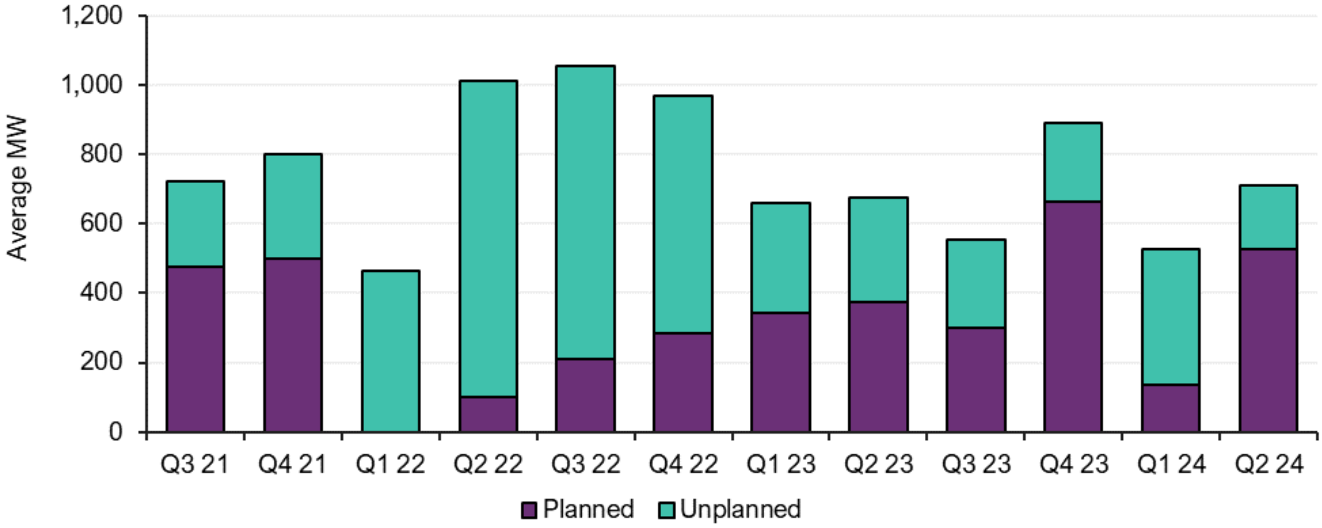
As well supplying energy, coal generators play a crucial role in stabilising power systems by providing system strength through inertia and voltage control.

Figure 6 compares planned and unplanned outages at Victorian coal generators over the last three years. Energy Australia's accelerated maintenance program of Yallourn, involving major planned outages for all four generating units to improve safety, reliability, and performance ahead of its planned closure in mid-2028, contributed to the increase of planned outages throughout 2023-24[19].

[19] See https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-accelerates-investment-energy-supply-reliability-following-2022.

There were fewer unplanned outages in 2023-24 than in 2022-23. On 15 April 2022, Loy Yang A Unit 2 went offline following an electrical fault with the generator[20], and this outage was extended to October 2022[21] due to the unavailability of specialised materials and global supply chain issues. Increased availability at both Loy Yang A and Loy Yang B in 2023-24 accounted for most of the reduction in total outages[22] compared to the previous year.

Figure 6 Victorian coal generation planned and unplanned outages, FY 2021-22 to 2023-24 (MW)



Renewable resources

Figure 7 illustrates that wind and solar generation continued to grow in the 2023-24 year, particularly in Q1 2024, which saw a 20% increase in maximum combined generation compared to Q1 2023.

This increase was predominantly driven by growth in semi-scheduled solar (12%) and distributed PV (15%). In Q4 2023, Victoria also saw an increase in wind generation due to Berrybank 2 and Mortlake South[23]. However, low wind in Q2 2024 (particularly in June 2024) contributed to wind generation that quarter being 4% lower than Q2 2023.

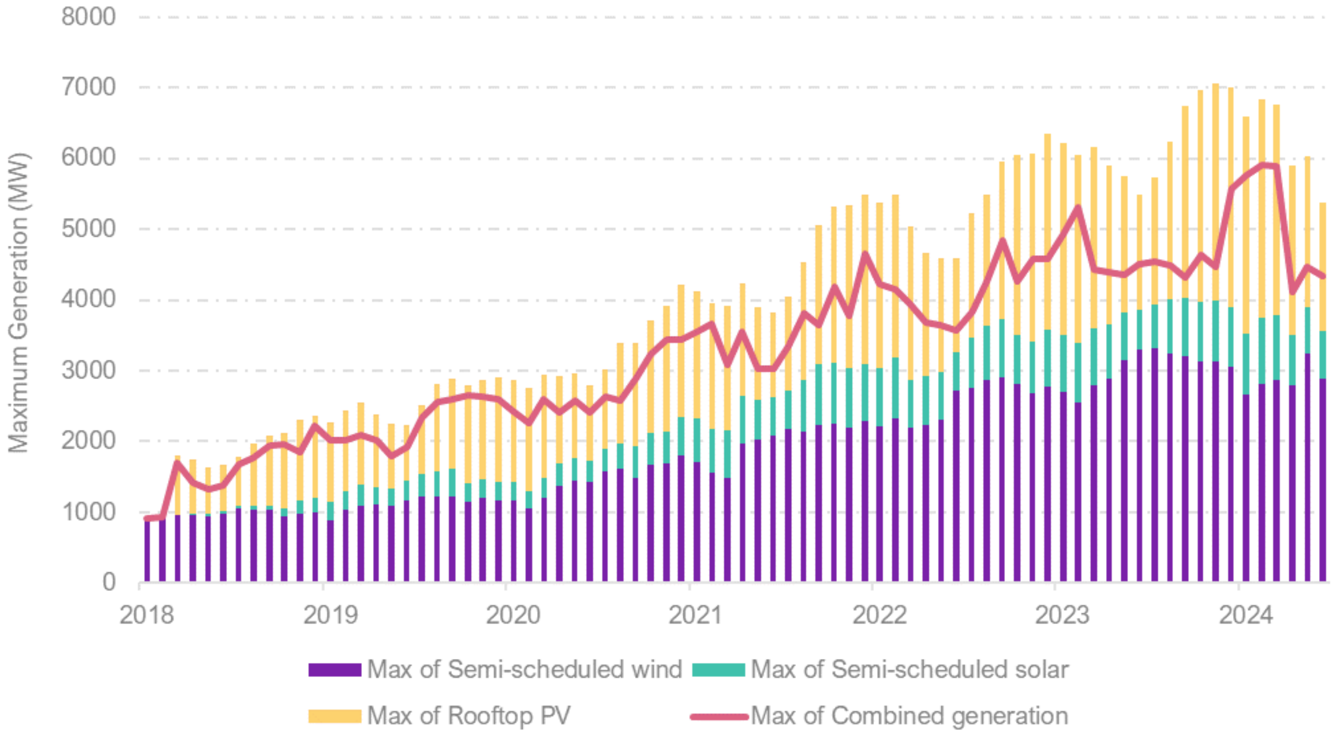
[20] See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2022/june/loy-yang-a-unit-2-generator-fault---update-on-expected-return-to.

[21] See https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/media-centre/2022/220912-loy-yang-a-unit-2-generator-fault-update-on-expected-return-to-service.pdf.

[22] See https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf.

[23] See aemo.com.au/-/media/files/major-publications/qed/2023/quarterly-energy-dynamics-q4-2023.pdf.

Figure 7 Actual Victorian maximum generation from renewable resources, 2018 to 2024 (MW)



Other sources of generation

Despite a mild summer in 2023-24, Victoria's hydro generation was consistent with previous years[24]. There were some reductions in hydro generation in the third and fourth quarter of 2023, with the most significant occurring at Murray, Eildon and McKay Power Stations[25]. Murray and McKay Power Stations experienced planned outages from March 2023 to August 2023.

Victorian gas-fired generation also dropped in the third and fourth quarter of 2023. However, gas-fired generation rose in all hours of the day in Q2 2024 in response to the decreases in wind and hydro generation[26].

2.3 Operational management

This section discusses how network operations have needed to adapt in the past year due to shifts in power system dynamics and supply geometry, specifically how these factors have reduced system resilience, resulting in the need for additional network constraints to manage the operational complexity.

2.3.1 Transformer reverse power flows

An increasing number of distributed generators (including distributed PV) connecting at the distribution level has led to reverse power flows at some terminal stations, which were originally established to supply customer loads.

[24] See https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q1-2024.pdf.

[25] See https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

[26] See https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q2-024.pdf.

During periods of low local demand and/or high local generation where consumers are self-reliant on distributed PV, combined with utility-scale distribution generation, power can flow from the distribution network to the DSN, reversing the traditional flow where the distribution network typically draws from the DSN. The reverse power flow conditions together with lightly loaded transmission lines lead to operational issues in voltage management in the DSN, due to lack of reactive support and/or onload tap ranges available at the connection points.

In the past year, reverse power flows occurred at 16 terminal stations, one more than in 2022-23, with Geelong Terminal Station experiencing a half-hour reverse flow for the first time. The total reverse flow hours were similar to what was observed in 2022-23, decreasing only slightly to 19,114 hours from 19,533 hours. **Table 2** outlines the number of hours in which reverse flows occurred at these terminal stations over the last five years and the associated primary cause of reverse flows.

Table 2 Yearly statistics of reverse flows at identified locations

Terminal station	Hours with reversed flows						Primary cause
	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	
Wemen 220/66 kV	1,926	3,241	3,546	3,053	3,610	3,082	Distribution network connected generation
Terang 220/66 kV	2,288	2,905	2,343	2,626	2,350	1,805	Distribution network connected generation
Kerang 220/66/22 kV	2,504	2,646	2,657	2,606	2,999	2,974	Distribution network connected generation
Horsham 220/66 kV	1,358	827	290	680	426	319	Distribution network connected generation
Red Cliffs 220/66/22 kV	536	477	1,933	2,192	2,636	2,121	Distribution network connected generation
Shepparton 220/66 kV	0	940	1,534	1,551	1,445	1,369	Distribution network connected generation
Ballarat 220/66 kV	0	838	1,912	1,659	1,589	1,395	Distribution network connected generation
Glenrowan 220/66 kV	0	0	592	2,582	2,617	2,739	Distribution network connected generation
South Morang 220/66 kV	0	0.5	14	56	84	266	Distribution network connected generation
Mount Beauty 220/66 kV	579	0	12	1,632	1,343	1,767	Distribution network connected generation
Bendigo 220/66 kV	0	0	4	24	39	144	Distributed PV
Cranbourne 220/66 kV	0	0	0	4	15	254	Distributed PV
Deer Park 220/66kV	0	0	0	18	35	203	Distributed PV
Morwell 220/66kV	0	1	2	38	66	137	Distribution network connected generation
Wodonga 330/22 kV	0	0	NA*	201	279	542	Distributed PV
Geelong 220/66 kV	0	0	0	0	0	0.5	Distributed PV
Total	**9,191**	**11,876**	**14,839**	**18,922**	**19,533**	**19,114.5**	

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

2.3.2 Voltage management at the time of low demand

The continued decline of minimum demand and reactive power consumption during minimum demand periods in Victoria[27] led to the installation of four additional 100 megavolt-amperes reactive (MVAr) shunt reactors at Keilor 220 kV and Moorabool 220 kV in 2021 and 2022 to maintain voltage levels within operational and design limits. These new reactors have significantly reduced the risk of over-voltages but have not entirely eliminated this operational challenge in the past year, primarily due to the continuous drop in minimum demand.

Under low demand conditions, and without intervention from the system operator, over-voltages can still occur on the Victorian transmission network. Short-term operational measures, such as de-energising a 500 kV transmission line, have become common practice during these periods to maintain system voltage requirements. For example, on 17 December 2023, 26 December 2023, and 31 December 2023 the Hazelwood to South Morang No. 1 500 kV line was de-energised to resolve the high voltage issue driven by low demand situation.

Reactive power injection from the distribution networks to the DSN has also contributed to the challenges of managing high DSN voltages. In 2023-24, out of 32 terminal stations assessed, 28 terminal stations were found to have been injecting reactive power for more than 10% of the year. Among these terminal stations, for example, 10 terminal stations were found to be injecting above 30 MVAr for more than 10% of the year. To address projected low demand over the next decade, AVP is undertaking the Metropolitan Melbourne Voltage Management RIT-T[28] to evaluate voltage management options for metropolitan Melbourne.

Increased integration of BESS into the grid is expected to alleviate the voltage control issues in the DSN. AVP is seeking a coordinated approach with DNSPs and Declared Transmission System Operators (DTSOs) to determine additional cost-effective solutions, such as:

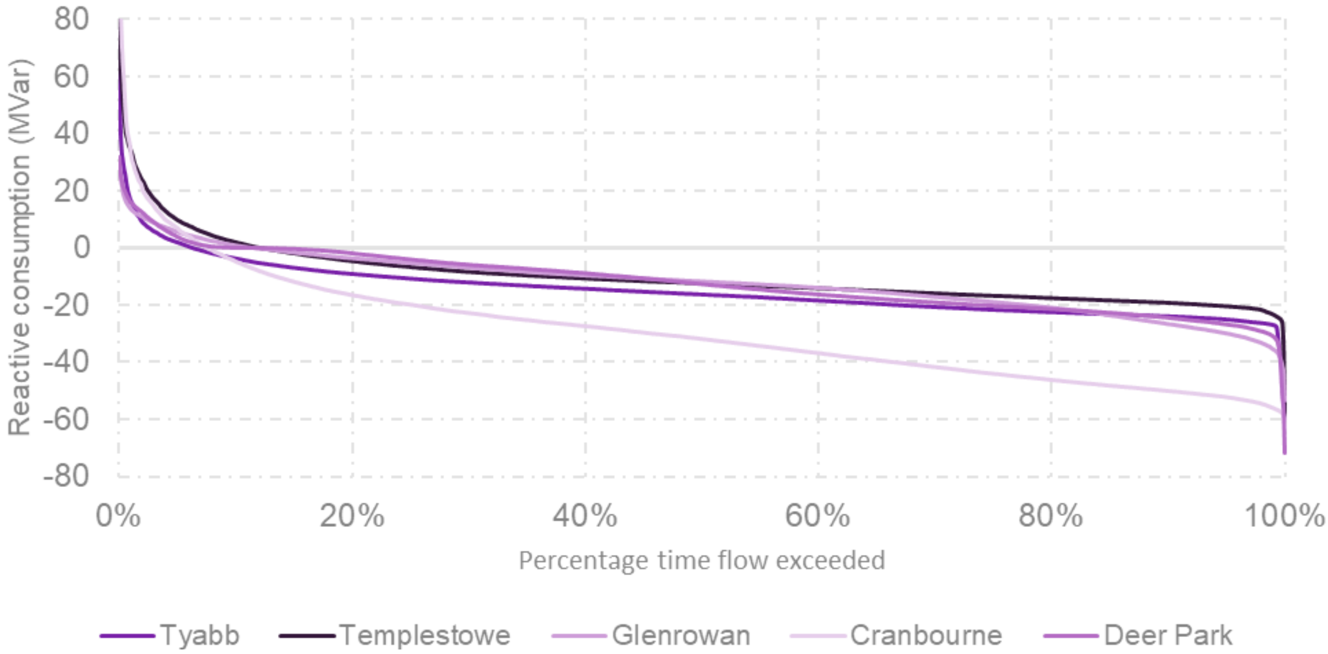
- transformer tap changers with a wider voltage range,
- installing dynamic or static reactive power plants to absorb excessive reactive power.

Figure 8 shows the yearly net reactive consumption (a negative value indicates injection into the DSN) at Tyabb, Templestowe, Glenrowan, Cranbourne and Deer Park terminal stations as examples to demonstrate this issue. The consumed MVAr were estimated by subtracting the historical reactive power injection by respective capacitor banks, if any, from the reactive power through the transformer(s) at these locations.

[27] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/2019/reactive-power-rit-t/victorian-reactive-power-support-pacr.pdf.

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

Figure 8 Net reactive power flow duration curve at Tyabb, Templestowe, Glenrowan, Cranbourne, and Deer Park (MVAr) in 2023-24



2.3.3 Maintaining system strength

Traditionally provided by synchronous generation, system strength refers to the power system's ability to maintain a stable voltage waveform at any given location, both during steady state operation and following a disturbance[29]. Victoria's energy transition, which includes more IBR like renewable energy generation and batteries, introduces challenges due to their lower system strength compared to traditional sources.

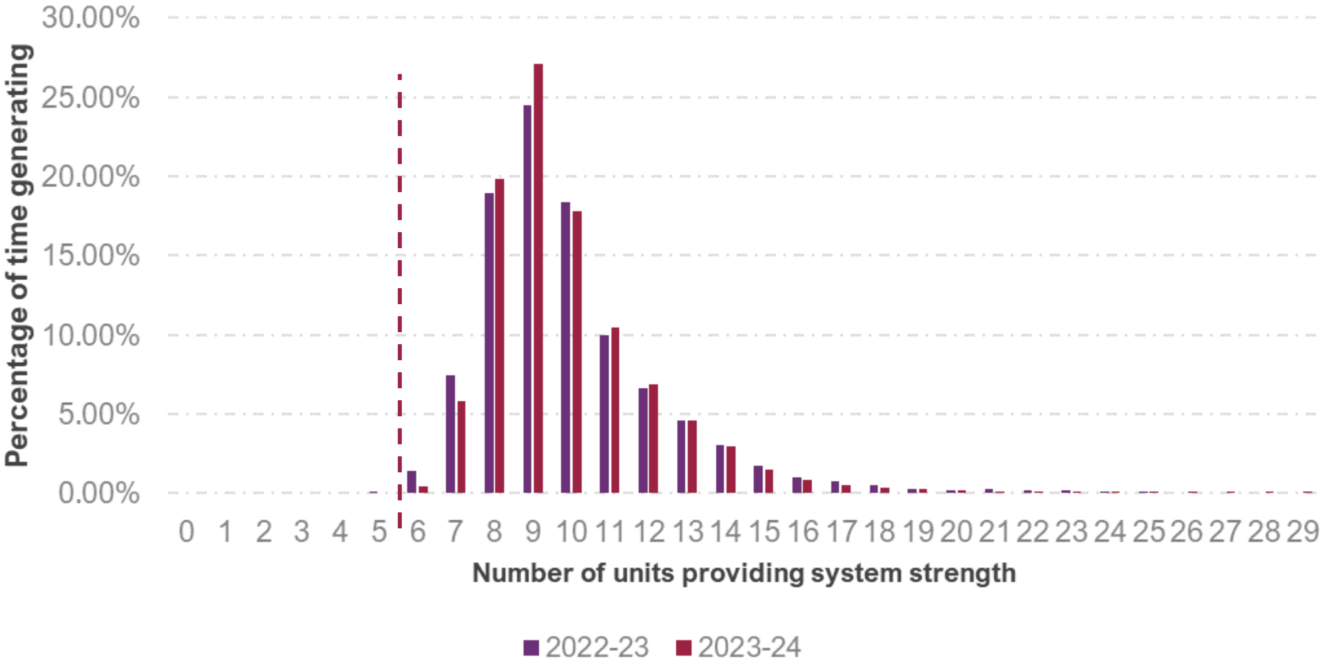
To maintain system stability, it is essential that the minimum system strength is maintained. This involves controlling the voltage waveform, and ensuring the system can manage fault currents during disturbances. Increased displacement of synchronous generation units due to unfavourable market conditions is expected to reduce fault levels at most system strength nodes in Victoria.

Currently, a minimum combination of five synchronous generating units is needed to be online to provide sufficient system strength in Victoria to withstand a credible fault and loss of a synchronous unit (the most critical contingency for these combinations is loss of a Loy Yang A unit)[30]. In 2023-24 in Victoria, six or more synchronous units were always online. Compared to 2022-23, it was also less common to observe fewer than eight synchronous generators online, as shown in **Figure 9**.

[29] https://aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength---project-specification-consultation-report_final.pdf.

[30] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

Figure 9 Available system strength units during 2023-24 compared to 2022-23



In its 2023 System Strength report [31], AEMO did not identify any system strength shortfalls for the period to 1 December 2025. The development of a substantial number of IBR will continue to drive investment in system strength services over the longer term.

The anticipated Koorangie Energy Storage System is expected to improve system strength in the Murray region and allow the stable connection of up to 300 MW of additional renewable generation[32], and the Ararat 250 megavolt-amperes (MVA) synchronous condenser will enable up to 600 MW of renewable energy in the Western Victoria Renewable Energy Zone (REZ)[33]. Currently, AEMO is undertaking the Victorian System Strength Requirement RIT-T to address system strength requirements in Victoria from December 2025[34]. Studies conducted in 2023 did not identify any new system strength gaps beyond those already declared[35].

2.3.4 Geographical shift in Victorian generation

While the Latrobe Valley continues to be Victoria's dominant supply source, the state's drive for increased investment in renewable energy has led to a shift towards the west, especially in regions rich in wind and solar resources. **Figure 10** below displays network loading duration curves for the 500 kV flow from the Latrobe Valley,

[31] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2023-system-strength-report.pdf.

[32] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf.

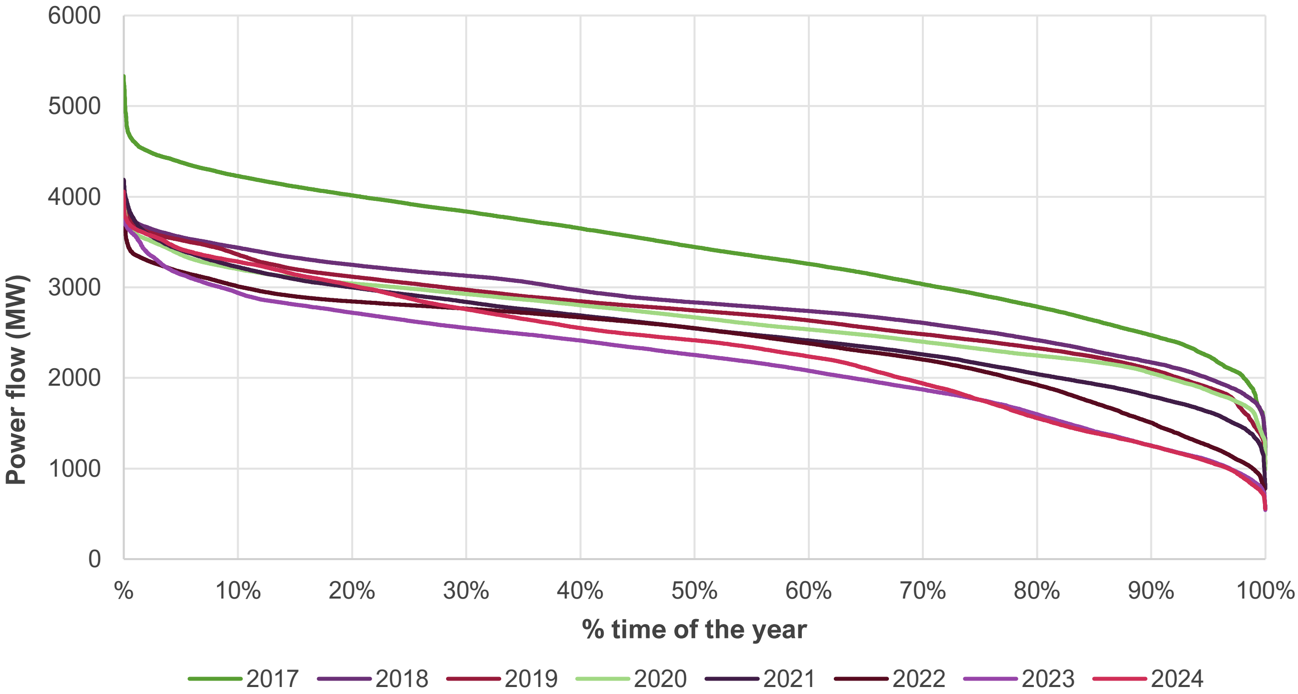
[33] See https://www.energy.vic.gov.au/renewable-energy/vicgrid/transmission-projects-in-victoria.

[34] See Section 3.2.2 of the VAPR, and https://aemo.com.au/en/initiatives/major-programs/victorian-system-strength-requirement-regulatory-investment-test-for-transmission

[35] See page 25, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/enhanced-locational-information/2024-eli-report.pdf.

illustrating the flow of these lines decreasing with longer periods at the lower end of the range since the retirement of Hazelwood Power Station in 2017.

Figure 10 Actual network loading duration curves from Latrobe Valley to Melbourne, financial years 2017 to 2024 (MW)



Westbound flow from the Latrobe Valley is expected to decrease further, particularly after the announced 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.

AVP is currently reviewing the operational configuration of the Latrobe Valley DSN, accounting for the expected retirement of Yallourn Power Station. This will optimise the flow distribution on both the 500 kV and 220 kV lines and in turn reduce the reliability risks after the retirement of Yallourn W Power Station identified in the 2023 VAPR.

Figure 11 and **Figure 12** shows the network loading duration curves due to generation from west and southwest Victoria into the greater Melbourne and Geelong areas.

In recent years, more renewable generators have been connected in western Victoria, increasing the flows towards metropolitan areas from both western and southwestern generation, and this trend is expected to continue. Some generation-driven limitations in western and southwestern Victoria have already begun to emerge.

Figure 11 Actual network loading duration curves from west towards Geelong and Melbourne through Moorabool 220 kV, financial years 2017 to 2024 (MW)

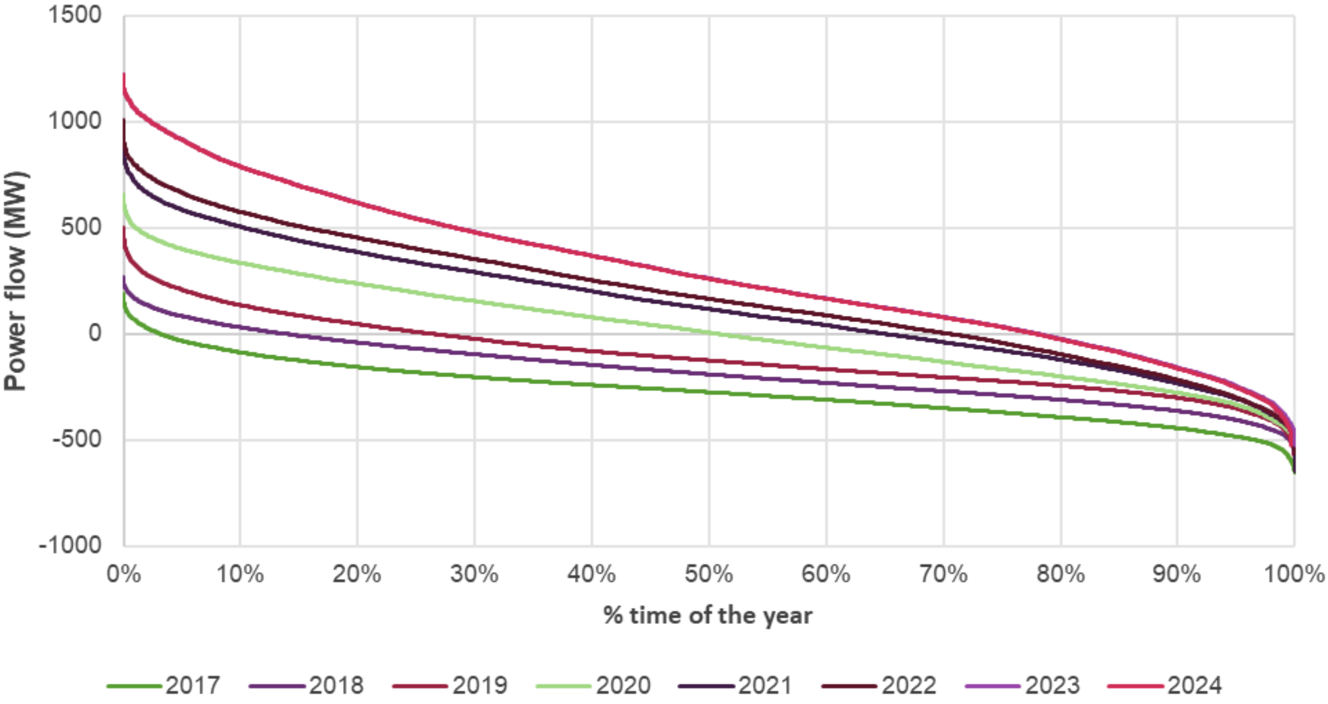
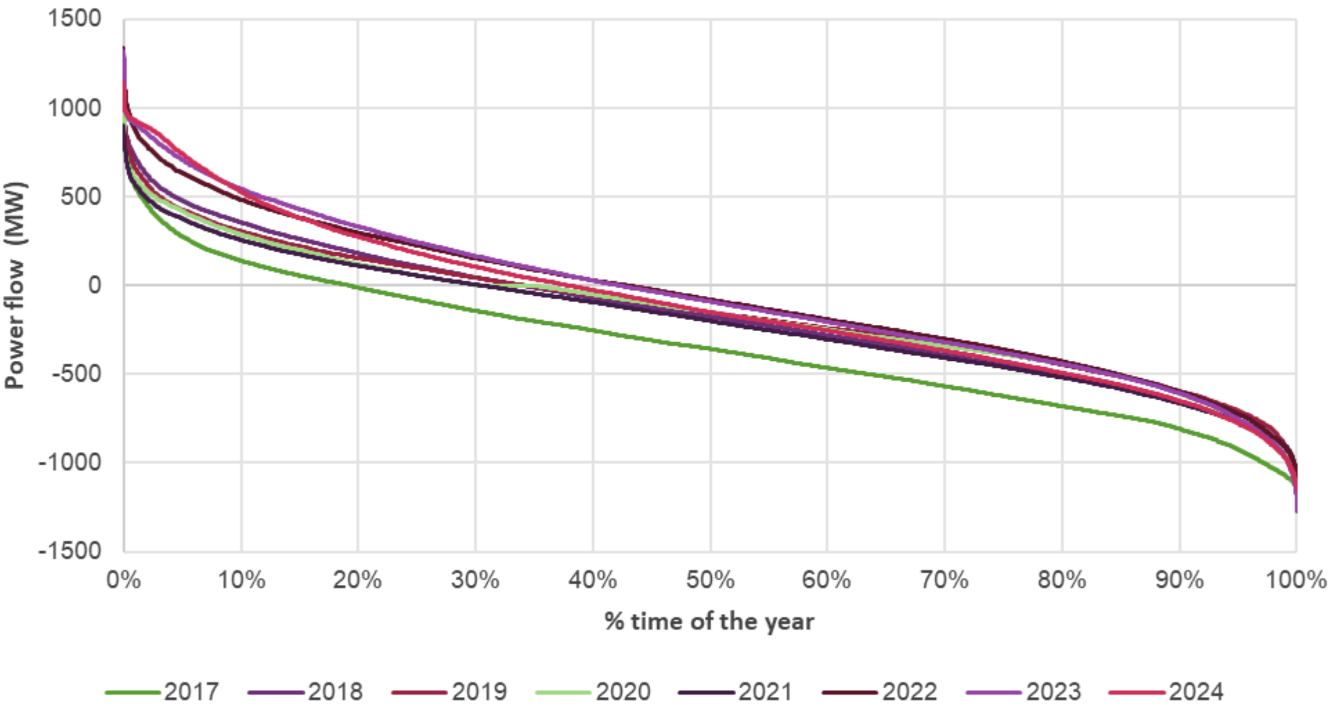


Figure 12 Network loading duration curves from southwest towards Geelong and Melbourne through Moorabool 500 kV, financial years 2017 to 2024 (MW)



Network curtailment in renewable generation

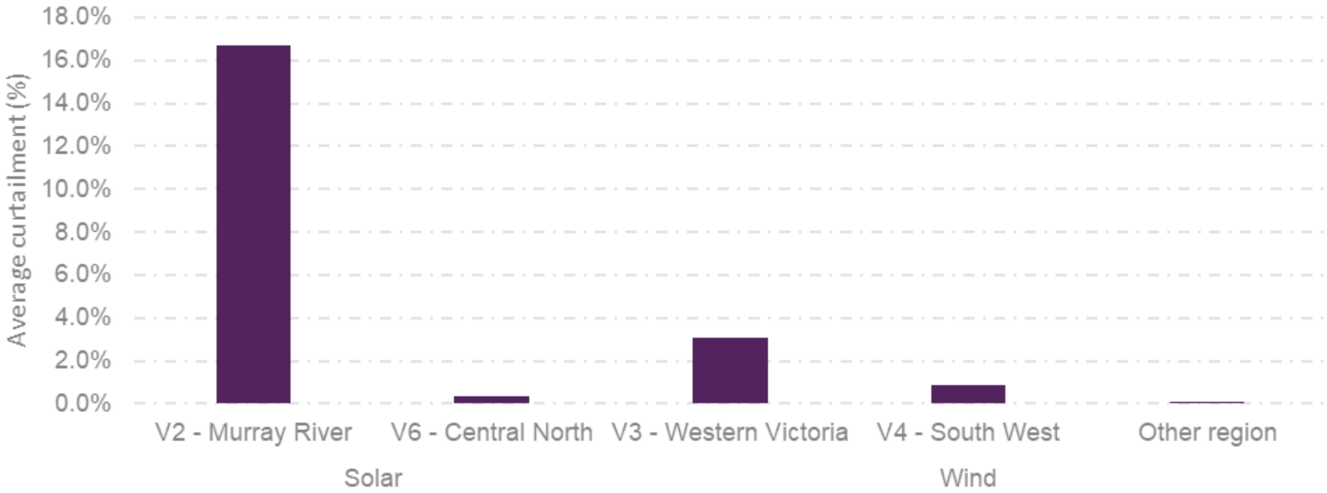
Curtailment in renewable energy refers to the forced or voluntary reduction of electricity output, which can be categorised as either network[36] or economic curtailment respectively[37]. Network curtailment is the only aspect AVP can control, whereas economic curtailment is driven by market forces.

VRE (solar and wind) overall availability (in megawatt hours (MWh)) and network curtailment[38] (MWh) of semi-scheduled generation in Victoria over the 2023-24 period is summarised in **Table 3**, with **Figure 13** illustrating the average network curtailment[39] in different Victorian REZs for the same period.

Table 3 Summary of total VRE availability and network curtailment in Victoria

Fuel	REZ	Average curtailment (%)	Average curtailment (MW)	Curtailment (MW)
Solar	V2 – Murray River	16.7	4	219,267
	V6 – Central North	0.4	0	2,623
Wind	V3 – Western Victoria	3.1	1	123,990
	V4 – South West	0.9	0	39,770
	Other region	0.0	0	18

Figure 13 Average VRE network curtailment (%) in Victorian REZs for 2023-24



In 2023-24, V2-Murray River REZ experienced the highest level of curtailment due to network constraints, at 16.7%. Voltage oscillations and collapse constraints are predominant in V2 and are mostly responsible for these curtailments. Existing VRE generators connected to the north-western 220 kV subnetwork are being constrained

[36] Network curtailment occurs when there are physical limitations or constraints on the transmission network. This curtailment is necessary to ensure safe and reliable operation of the transmission network.

[37] Economic curtailment occurs when generation is reduced due to economic reasons, such as low market prices. Renewable energy often has lower marginal costs, however, if the prices are very low, generation may be curtailed due to competition in the market.

[38] See curtailment methodology at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/enhanced-locational-information/a2-indicator-definitions-and-methodology.pdf.

[39] Average curtailment is calculated using curtailment (MWh) divided by availability (MWh).

to ensure that network thermal limits are not exceeded. Section 3.1 will further discuss these constraints. Network curtailment by VRE semi-scheduled generators in V2 and V3 is detailed in **Tables 4 and 5**.

Table 4 V2 REZ VRE semi-scheduled curtailment, 2023-24

DUID	Generator name	Maximum capacity (MW)	Average curtailment	Average curtailment (MW)	Curtailment (MWh)
BANN1	Bannerton Solar Park	88	35.3%	8.0	70,460
COHUNSF1	Cohuna Solar Farm	27	0.0%	0.0	5
GANNSF1	Gannawarra Solar Farm	50	2.3%	0.2	2,128
KARSF1	Karadoc Solar Farm	90	12.3%	2.5	21,679
KIAMSF1	Kiamal Solar Farm	200	6.7%	2.8	24,886
WEMENSF1	Wemen Solar Farm	88	40.1%	7.0	61,314
YATSF1	Yatpool Solar Farm	81	24.1%	4.4	38,794

Table 5 V3 REZ VRE semi-scheduled curtailment, 2023-24

DUID	Generator name	Maximum capacity (MW)	Average curtailment	Average curtailment (MW)	Curtailment (MWh)
ARWF1	Ararat Wind Farm	241	6.4%	5.1	44,490
BULGANA1	Bulgana Green Power Hub	204	0.7%	0.6	5,573
CROWLWF1	Crowlands Wind Farm	79	5.6%	1.6	14,177
ELAINWF1	Elaine Wind Farm	82	0.9%	0.1	1,077
KIATAWF1	Kiata Wind Farm	31	3.0%	0.3	2,758
MERCER01	Mt Mercer Wind Farm	131	4.9%	1.1	9,778
MOORAWF1	Moorabool Wind Farm	305	1.0%	0.3	2,876
MUWAWF1	Murra Warra Wind Farm	226	5.1%	3.9	34,727
MUWAWF2	Murra Warra Wind Farm Stage 2	203	5.5%	3.6	32,157
YENDWF1	Yendon Wind Farm	142	0.2%	0.1	653

While minor augmentations have been made, including several new control schemes and rating upgrades as part of REZ Development Plan (RDP) Stage 1 projects, the 220 kV subsystem remains relatively weak and has limited thermal capacity. As a result, curtailment levels are expected to increase unless new transmission lines are constructed.

The Western Renewable Link (WRL) and Victoria – New South Wales Interconnector West (VNI West) projects represent transformative investments poised to unlock a substantial amount of renewable energy generation. The WRL is anticipated to alleviate many congestion-related constraints in the 220 kV Ballarat – Horsham – Murra Warra network, while both WRL and VNI West will facilitate future expansion. Although interest in connecting to these areas may still exceed capacity, by alleviating network congestion and reducing network curtailment, these projects will make it possible to integrate more renewable energy than would otherwise be achievable.

As shown above in **Figure 13,** south-west Victoria (where has mainly wind generation) also experienced VRE curtailment. With newly committed VRE projects in late 2024, congestion is most likely to occur until the Mortlake Turn-in is completed. It is anticipated that without new 500 kV lines, new generation seeking connection in south-east Victoria will introduce significant congestion on this part of the Victorian DSN.

3 Review of network congestion

Assessing the Victorian DSN's capacity, performance and identifying limitations or bottlenecks that may impact operations is crucial for determining its capability to meet current and future demands. This review aims to offer insights into the network's efficiency and readiness to support Victoria's transition as it heads towards a decarbonised electricity grid.

This section assesses the capability of the Victorian DSN through analysis of its network limits and interconnector capabilities. Key network congestion insights include:

- Victoria's net energy exports and the duration of interconnector exports from Victoria have steadily increased, nearing levels seen before Hazelwood's closure, driven by increased renewable energy generation and lower regional demand.
- Of the top 10 Victorian transmission constraints in 2023-24, eight are from the V2-Western Victoria and V3-Murray River REZs. The recently commissioned VNI East upgrade, minor augmentations as part of the Victorian Government's RDP initiatives, and reactors at KTS and MLTS have collectively helped reduce the constraint impact in 2023-24.

3.1 Top binding constraints

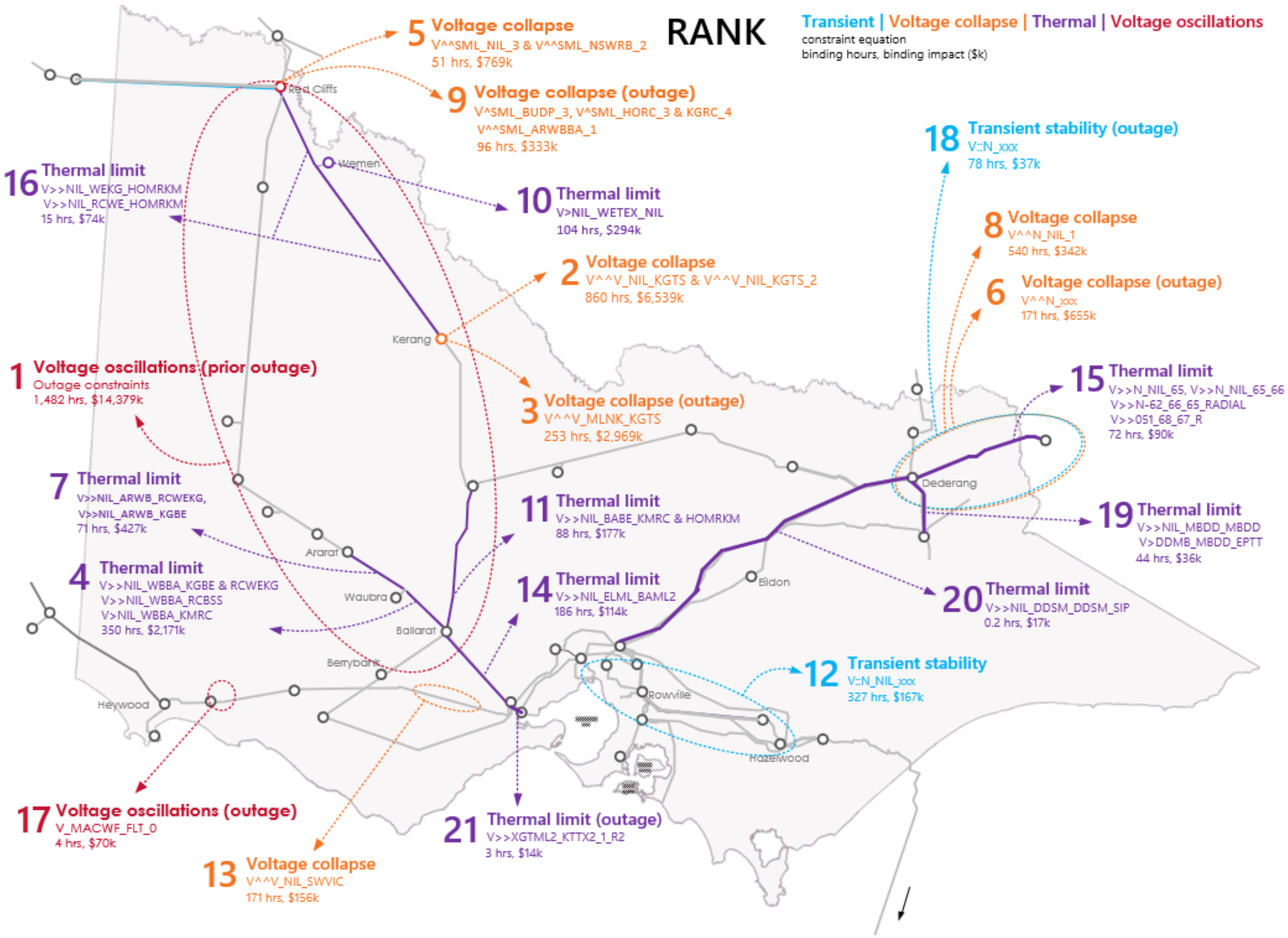
Transmission network constraints are formulated to model particular system limits (thermal, voltage, and stability) for system configurations, as necessary, to ensure the safe, reliable, and efficient operation of the power system[40].

This section summarises the Victorian transmission network constraints that resulted in the highest dispatch impacts during 2023-24 and compares these to outcomes during 2022-23. The ranking of each constraint (or group of constraints) was determined by the calculated 'binding impact' of the constraints. The binding impact of a constraint is derived by combining the marginal value[40] 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, in other words, the change in dispatch cost for a marginal change in the network limit. It does not represent the market benefit of investment to remove the constraint in absolute terms.

Figure 14 summarises the top 21 highest impact constraints in 2023-24 in the Victorian transmission network by type and region, as well as the binding hours and relative financial impact in dollars. While the constraints summarised in this section are those with the most significant market impact historically, investment to remove any specific constraint would also require consideration of limitations that may bind immediately behind these limits and reduce the benefits unless those constraints are also alleviated. For example, investment to remove constraint #2 in **Figure 14** would not result in unconstrained flows along Wemen to Kerang, as this line is also limited by constraint #16. Constraints that currently do not bind at all may begin to bind as the binding limits are removed.

[40] See https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint-Frequently-Asked-Questions.pdf.

Figure 14 Map of the most significant Victorian transmission constraints in 2023-24



3.1.1 Western Victoria and Murray River REZs

This part of the Victorian network (highlighted by the red dashed oval on **Figure 14** above) is characterised by significant investment in new renewable generation (wind and solar) and is experiencing outages to facilitate connection and commissioning of these projects. It is a relatively weak part of the Victorian network, subject to thermal, voltage oscillation and voltage collapse constraints that bound more in 2023-24 than 2022-23. Of Victoria's top 10 constraints in 2023-24, eight are from this region (see **Table 6** below for more information)

Murray River REZ has attracted a significant number of investments in solar generation. Both voltage oscillation and thermal limit constraints are currently restricting the output of generators within this REZ. The implementation of VNI West will upgrade transfer capability between Victoria and New South Wales and increase the ability for renewable generation to connect in this REZ[41]. It is also expected that voltage oscillation constraints affecting this area will be reduced following the completion of Project EnergyConnect (PEC).

Western Victoria through the Ballarat – Ararat – Horsham – Murra Warra corridor continues to see more investments in wind generation. The existing and committed renewable generation within this REZ exceeds 1 GW, all of which is wind generation[38]. Both voltage and thermal limits are constraining the outputs of renewable generation located in this area under certain conditions.

WRL is an anticipated project which is expected to alleviate these constraints. Projects being delivered as a part of the Victorian Government's RDP Stage 1 (a new synchronous condenser at Ararat, a new BESS at Koorangie, and a number of minor augmentations) are also expected to reduce these constraints.

The binding hours for the Ararat to Waubra thermal constraint has been reduced significantly, after an RDP Stage 1 project milestone, compared to last year, and may improve further on completion of WRL.

Table 6 Constraint equations with significant binding durations or impacts – Western Victoria and Murray River REZs

Rank	Equation(s)	Binding hours		Binding impact		Description
		2022-23	2023-24	2022-23	2023-24	
1	North-west Victoria voltage oscillations (prior outage)	978^A	1,482^A	$9,468k^A	$14,379k^A	This represents a set of the network constraint equations associated with voltage oscillation during a range of prior outage conditions. More outages have occurred in 2023-24 compared to 2022-23 and, due to this, these constraints have bound more. AEMO is continuously reviewing these constraints as revised models are obtained and based on upcoming outage schedules.
2	Kerang voltage collapse V^^V_NIL_KGTS V^^V_NIL_KGTS_2	970	919	$6,043k	$6,590k	To avoid voltage collapse at Kerang due to the loss of Horsham – Murra Warra – Kiamal 220 kV line considering Murraylink Very Fast Run Back (VFRB) scheme disabled.
3	Wemen to Kerang voltage collapse V^^V_MLNK_KGTS	150	253	$1,905k	$2,969k	To avoid voltage collapse at Kerang due to the loss of Horsham – Murra Warra – Kiamal 220 kV line during an outage of Murraylink.
4	Waubra to Ballarat thermal V>>NIL_WBBA_RCWEK	247	355	$2,296k	$2,184k	To avoid overloading Waubra to Ballarat 220 kV line on trip of the Red Cliffs-Wemen-Kerang 220 kV line or Kiamal to Red Cliffs 220

[41] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/enhanced-locational-information/a7-victoria.pdf.

Rank	Equation(s)	Binding hours		Binding impact		Description
		2022-23	2023-24	2022-23	2023-24	
	G, V>>NIL_WBBA_KGBE, V>NIL_WBBA_KMRC, V>>NIL_WBBA_RCBSS					kV line or Kerang to Bendigo 220 kV line or Red Cliffs to Buronga 220 kV line.
5	Red Cliffs voltage collapse V^^SML_NIL_3 V^^SML_NSWRB_2	159	51	$811	$769	To avoid voltage collapse at Red Cliffs for the loss of Bendigo to Kerang 220 kV, Darlington Point to Balranald (X5) or Balranald to Buronga (X3) 220 kV lines when the New South Wales Murraylink runback scheme is unavailable.
7	Ararat to Waubra thermal V>>NIL_ARWB_RCWEKG, V>>NIL_ARWB_KGBE	707	71	$6,394k	$427k	To avoid overloading Ararat to Waubra 220 kV due to the loss of 220 kV lines at either Kerang to Bendigo, or Red Cliffs to Wemen to Kerang.
9	Red Cliffs voltage collapse V^SML_HORC_3, V^SML_KGRC_3, V^^SML_ARWBBA_1, V^SML_BUDP_3	-	96	-	$333	These are the outage constraints to avoid voltage collapse at Red Cliffs. Outages are of Horsham to Red Cliffs through Murra Warra 220 kV, Kerang to Red Cliffs through Wemen 220 kV, Ararat to Waubra 220 kV lines. V^SML_BUDP_3 is to avoid voltage collapse for loss of Bendigo to Kerang 220 kV line. This is also an outage constraint at the time of Buronga to Balranald (X3) or Balranald to Darlington Pt (X5) outage.
10	Wemen Transformer thermal[B] V>NIL_WETEX_NIL	259	104	$1,548k	$294k	Prevent pre-contingent overload of Wemen 220/66 kV transformer in the 66 to 220 kV direction (not part of DSN).
11	Ballarat to Bendigo thermal V>>NIL_BABE_HOMRKM, V>>NIL_BABE_KMRC	144	88	$342k	$177k	To avoid overloading Ballarat to Bendigo for loss of Horsham – Murra Warra – Kiamal 220 kV or Kiamal to Red Cliffs 220 kV lines.
16	Red Cliff – Wemen – Kerang thermal V>>NIL_WEKG_HOMRKM, V>>NIL_RCWE_HOMRKM	157	15	$252k	$74k	To avoid overloading the Red Cliff – Wemen – Kerang 220 kV line for the loss of Horsham – Bulgana – Crowlands 220 kV line or Horsham – Murra Warra – Kiamal 220 kV line.

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.

3.1.2 South-west corridor and the Heywood interconnector

This area encompasses some of the large wind farms in Victoria (such as Stockyard Hill, Dundonnell and Macarthur), and the alternating current (AC) interconnection to South Australia through Heywood Terminal Station. New constraints have emerged in the south-west corridor in Victoria recently, existing constraints bound more frequently than the previous year. This is due to higher wind generation connecting in this corridor, and new limitations emerging on the Heywood interconnector to manage secure operation in South Australia. Compared to last year, the transient stability and other constraints around Heywood interconnector have been improved.

Table 7 presents further details on each of these limitations.

Table 7 Equations with significant binding durations or impact – south-west corridor

Rank	Equation	Binding hours		Binding impact		Description
		2022-23	2023-24	2022-23	2023-24	
13	Haunted Gully to Moorabool and Mortlake to Moorabool Voltage collapse V^^V_NIL_SWVIC	88	171	$61k	$156k	To manage flow towards Moorabool across Haunted Gully to Moorabool and Mortlake to Moorabool 500 kV lines due to the loss of Haunted Gully to Moorabool 500 kV line and both Alcoa Portland (APD) potlines.
14	Elaine to Moorabool thermal V>>NIL_ELML_BAML2	108	186	$61k	$114k	To avoid overloading Elaine to Moorabool 220 kV line on trip of Ballarat to Moorabool No. 2 220 kV line.
17	Macarthur Wind Farm voltage oscillation V_MACWF_FLT_0	24	4	$276k	$70k	Limit generation at Macarthur wind farm to 0MW to manage post-contingent voltage oscillations.
21	Moorabool to Geelong thermal V>>XGTML2_KTTX2_1_R2	-	3	-	$14k	This is a multiple outage thermal constraint. Outages are of Geelong to Moorabool No. 2 220 kV line and Keilor A2 500/220 kV transformer. This constraint is formulated to avoid overloading on the remaining Moorabool to Geelong 220 kV line on trip of Sydenham to Keilor 500 kV line.

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

Constraints in the east of Victoria are primarily dominated by limitations across VNI East[42]. There are several thermal constraints limiting flows between South Morang and Murray, while constraint types including, thermal, transient stability and voltage collapse, impact the flow across the Victoria – New South Wales border region. Two constraints had higher binding hours than the previous year (Dederang to South Morang thermal constraint, and Mt Beauty to Dederang thermal constraint).

Table 8 provides further details on these limitations.

There has been a significant reduction in VNI export voltage collapse constraints during outage scenarios due to the increased binding of a thermal constraint for the trip of Lower Tumut to Wagga line in New South Wales.

Table 8 Equations with significant binding durations or impact – Eastern Victoria, VNI and Latrobe Valley

Rank	Equation	Binding hours		Binding impact		Description
		2022-23	2023-24	2022-23	2023-24	
6	VNI export voltage collapse during outages V^^N_xxx	835	171	$1,599k	$655k	Avoid voltage collapse around Murray for loss of all APD potlines during planned transmission equipment outages. These constraints each behave similarly to their system normal counterpart V^^N_NIL_1. These constraints are invoked during outages of any line in, or connecting to, the 330 kV corridor between Victorian and New South Wales capital city load centres. Outages of other significant lines including 500 kV Latrobe Valley lines in Victoria and 220 kV lines in Southwest New South Wales also may require such constraints to be invoked.

[42] VNI East is the existing Victoria-New South Wales interconnector through Dederang and South Morang

Rank	Equation	Binding hours		Binding impact		Description
		2022-23	2023-24	2022-23	2023-24	
8	VNI voltage collapse V^^N_NIL_1	330	540	$558k	$342k	To avoid voltage collapse in northern Victoria and southern New South Wales for loss of APD.
12	Transient stability V::N_NIL_xxx	82	327	$44k	$167k	To prevent transient instability for fault and trip of Hazelwood to South Morang line during system normal.
15	VNI thermal overload V>>N_NIL_65_66 V>>N_NIL_65 V>>051_68_67_R V>>N-NIL_HA	121	72	$103k	$90k	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.
18	VNI export transient stability during outages V::N_xxx	705	78	$1,186k	$37k	Prevent transient instability for fault and trip of Hazelwood to South Morang line during planned transmission equipment outages.
19	Mount Beauty to Dederang thermal V>>NIL_MBDD_MBDD V>DDMB_MBDD_EPTT	-	44	-	$36k	To prevent overloading of Mount Beauty to Dederang 220 kV line for the trip of parallel line. V>DDMB_MBDD_EPTT is an outage thermal constraint. Outage is of Dederang to Mount Beauty 220 kV line. This constraint equation is formulated to avoid overloading on the remaining Mount Beauty to Dederang 220 kV line on trip of Eildon to Thomastown 220 kV line.
20	Dederang to South Morang thermal V>>NIL_DDSM_DDSM_SIP	-	0.2	-	$17k	To avoid overloading on Dederang to South Morang 330 kV line (southern flow) for the trip of the parallel line, if SIPS available.

3.2 Interconnector capability

An interconnector's capability depends on conditions within the network, which vary throughout the year. AEMO publishes notional interconnector limits in the *Inputs, Assumptions and Scenarios Report* (IASR)[43] and a detailed summary of the capability and limits of interconnectors in its Monthly and Annual NEM Constraint Reports[44].

3.2.1 Analysis of interconnector performance

Victoria's net energy exports to neighbouring regions declined for three years following the closure of the Hazelwood Power Station in 2017. Since then, both net energy exports and the duration of interconnectors exporting energy from Victoria have steadily increased and are approaching levels similar to those before Hazelwood's closure, primarily due to the increase in Victorian renewable generation and reduction in regional demand.

Table 9 and **Table 10** summarise the trends in Victoria's export to other regions across the interconnectors.

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

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

In 2023-24, Victoria was a net exporter 81% of the time, as shown in Table 9 and **Figure 15**. However, Victorian interconnectors were often not exporting simultaneously. This accounts for Victoria's higher net flow percentage when comparing the interconnectors separately.

Table 9 Percentage (%) of time interconnector is exporting energy from Victoria

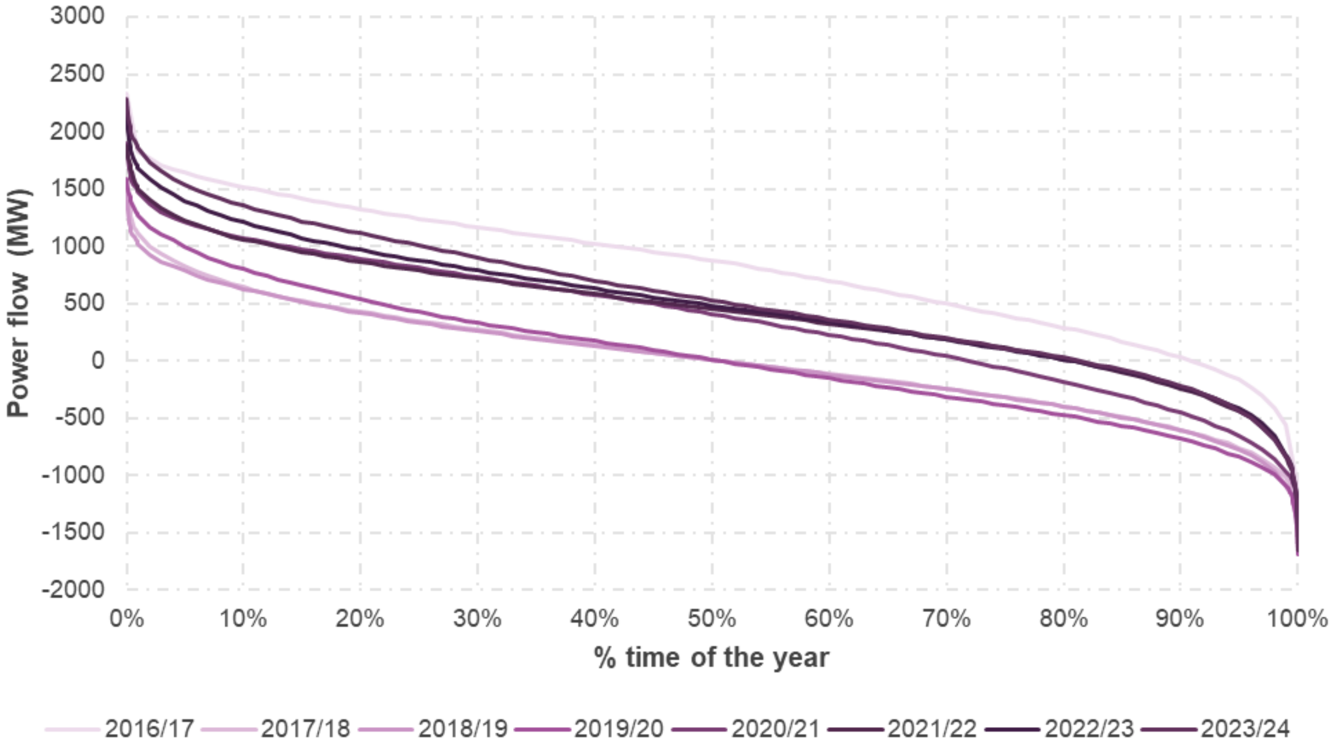
Interconnector	Five-year average before Hazelwood closure	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
VNI	84%	49%	50%	56%	71%	80%	71%	66%
Heywood	82%	46%	42%	36%	47%	52%	51%	57%
Murraylink	45%	35%	50%	62%	63%	67%	68%	68%
Basslink	44%	55%	43%	45%	59%	49%	67%	68%
Victoria (net)	**87%**	**51%**	**51%**	**51%**	**72%**	**81%**	**81%**	**81%**

Table 10 Net energy exported from Victoria (gigawatt hours, GWh)

Interconnector	Five-year average before Hazelwood closure	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
VNI	4,032	654	953	1,174	2,338	3,361	2,787	2,615
Heywood	1,824	-189	-388	-534	-117	232	99	461
Murraylink	48	-113	-36	152	289	468	432	484
Basslink	-533	-196	-496	-512	611	-279	929	1,250
Victoria (net)	**5,371**	**156**	**33**	**279**	**3,122**	**3,782**	**4,247**	**4,810**

Figure 15 represents the Victorian net energy flows for all interconnectors for the last eight years. Net energy flows in Victorian interconnectors continue to increase over the years since the closure of Hazelwood, with over half net exports to New South Wales and one quarter to Tasmania.

Figure 15 Victoria net interconnector flow duration curve, 2016-17 to 2023-24 (all interconnectors, MW)



Heywood Interconnector

The Heywood interconnector continues to operate below its maximum design limit of 650 MW in both directions because of stability risks identified following the South Australia black system event in 2016. The maximum transfer currently allowed is 600 MW from Victoria to South Australia, and 550 MW from South Australia to Victoria[45].

Net exports from Victoria into South Australia increased 360% in 2023-24 compared to 2022-23 and doubled compared to 2021-22. In anticipation that this trend will continue, as well as to enable increased imports, as part of the PEC Stage 1 inter-network test plan, AVP will work with ElectraNet and AEMO Operations to increase import and export limits to 650 MW, most likely by 2026. Currently, pre-simulation studies are underway to assess this increase.

Victoria – New South Wales Interconnector East (VNI East)

Victoria experienced significant transmission congestion in 2023 and exports to New South Wales through VNI were constrained to manage voltage and transient stability[46].

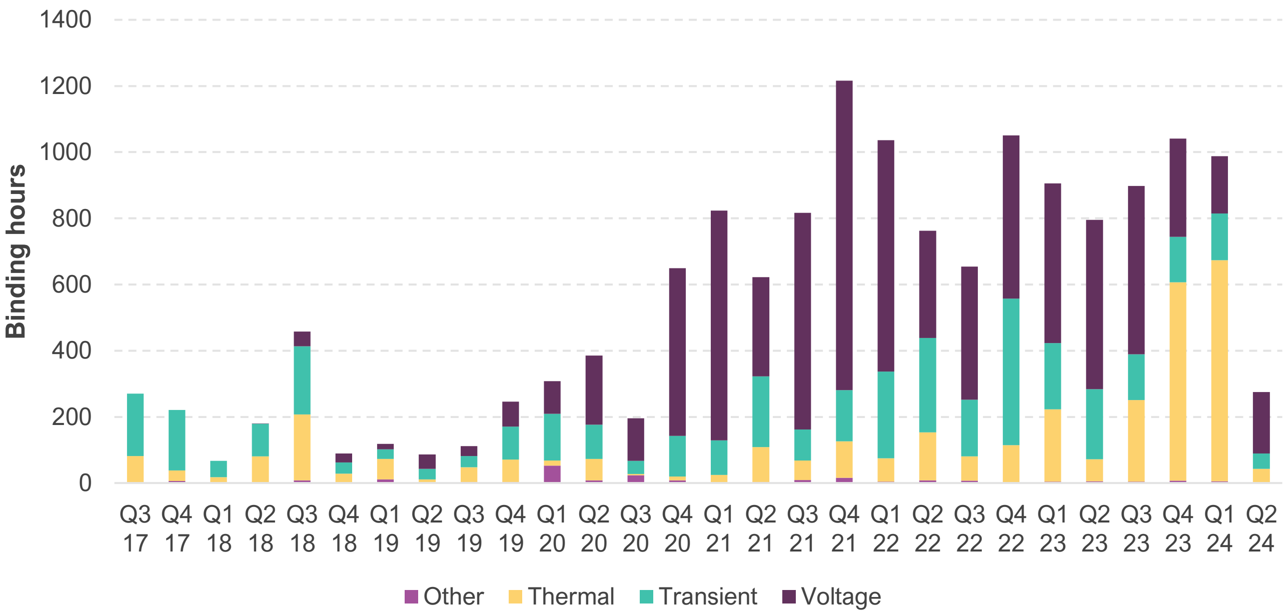
Figure 16 shows historical binding hours in VNI export for different constraints. In Q4 2023 and Q1 2024, binding hours due to thermal constraints increased significantly. The most significant was due to a system normal

[45] See page 10, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/interconnector-capabilities.pdf.

[46] See page 63, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/enhanced-locational-information/2024-eli-report.pdf.

constraint to avoid thermal overloading in New South Wales under a contingent condition. More details of these constraints are in Section 3.1.3.

Figure 16 Historical binding hours for export constraints along VNI by constraint type from Q3 2017 to Q2 2024



Basslink Interconnector

In 2023-24, Victorian net exports to Tasmania via Basslink rose by 34%[47] compared to 2022-23. For most of 2023-24, with the exception of Q3 2023[48], dry conditions led to reduced Tasmanian hydro output to preserve water storage levels[49].

Murraylink Interconnector

The 2023-24 maximum import levels for the Murraylink interconnector dropped by 64%[50] compared to 2022-23 and 9% compared to 2021-22, while total exports increased by 12% compared to the previous year. Murraylink had an unplanned outage in September 2023, due to the failure of capacitors at both ends. Murraylink was out of service due to a cable fault which occurred in March-April 2024, however the voltage control service at Red Cliffs was still in in service.

[47] Calculated using the sum of total energy exported (MWh) for 2022-23 and 2023-24.

[48] See https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf.

[49] See https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q2-2024.pdf.

[50] Calculated using the maximum import (MW) recorded in 2022-23 and 2023-24.

4 Network behaviour assessment under stress

The behaviour of a network under high stress conditions presents various challenges that can impact its reliability and security. Understanding how the network responds under these conditions will provide valuable insights into planning reviews which are crucial for improving reliability and minimising disruption during peak demand or critical events.

The analysis of high stress operating conditions and impacts on the DSN covered in this chapter includes:

- Maximum demand, daytime minimum demand, and night-time minimum demand.
- High wind generation.
- High interconnector flows.

All loading levels of the transmission lines were compared with the static ratings, whereas in the real system most of the DSN lines have dynamic line ratings which may have a higher rating depending on the operating conditions.

Key observations include:

- During maximum demand, none of the power system components loaded more than 100% under system normal condition and post N-1 contingencies.
- For low operational demand, lesser reactive power absorption by the synchronous units and reactive power injection from the distribution networks to the DSN has contributed to high DSN voltages that need to be carefully managed to stay within operational and design limits.
- During maximum wind generation, none of the DSN lines operate at their post-contingent thermal limits.

4.1 DSN condition under different operational demand

Table 11 compares the overarching DSN conditions during each operational demand snapshot.

Table 11 Summary of operating conditions for maximum and minimum demand in Victoria

Characteristic	Maximum demand	Daytime minimum demand	Night-time minimum demand
Date and time	22/02/2024 16:00	31/12/2023 13:00	25/12/2023 3:30
Victoria operational demand [A]	9,294 MW	1,564 MW	3,442 MW
Distributed PV	1,107 MW	3,077 MW	0 MW
Net power flow into Victoria via interconnectors [B]	504 MW • 101 MW from New South Wales • 576 MW from Tasmania • 173 MW to South Australia (173 MW export on Heywood and 0 MW import on Murraylink)	-563 MW • 398 MW to New South Wales • 462 MW to Tasmania • 297 MW from South Australia (142 MW import on Heywood and 155 MW import on Murraylink)	-1185 MW • 911 MW to New South Wales • 444 MW to Tasmania • 170 MW from South Australia (24 MW import on Heywood and 146 MW import on Murraylink)
Victorian renewable generation	3,120 MW, representing 37% of Victorian generation, consisting of: • 1,359 MW of wind • 258 MW of solar • 1,503 MW of hydro	122 MW, representing 6% of Victorian generation, consisting of: • 120 MW of wind • 2 MW of solar • 0 MW of hydro	2,108 MW, representing 45% of Victorian generation, consisting of: • 2,108 MW of wind • 0 MW of solar • 0 MW of hydro
Victorian synchronous generation	5,284 MW, representing 63% of Victorian generation, consisting of: • 4,016 MW of coal • 1,268 MW of gas	2,072 MW, representing 94% of Victorian generation, consisting of: • 2,072 MW of coal • 0 MW of gas	2,562 MW, representing 55% of Victorian generation, consisting of: • 2,562 MW of coal • 0 MW of gas
Temperature at Melbourne airport	34.5 C	19.6 C	17.2 C

[A] Operational demand in a region is demand that is met by local scheduled generating units, semi-scheduled generating units, and non-scheduled intermittent generating units of aggregate capacity ≥ 30 MW, and by generation imports to the region and by wholesale Demand Response. It excludes the demand met by non-scheduled non-intermittent generating units, non-scheduled intermittent generating units of aggregate capacity < 30 MW, exempt generation (e.g. rooftop solar, gas tri-generation, very small wind farms, etc), and demand of local scheduled loads[51].
[B] These are the measured flows during each snapshot and may differ from the interconnector's dispatch target.

4.2 Maximum demand condition

The maximum demand snapshot captures the conditions when many network elements experience their maximum loading. It is based on power system characteristics observed at 16:00 on 22 February 2024, when demand reached an annual peak of 9,294 MW.

On this day, there was a severe weather warning in Victoria. Stockyard Hill WF and Waubra WF were affected by the bushfires in the vicinity. At the time of maximum demand, the southward flows into Victoria across VNI East and westward flows across the Heywood interconnector from Victoria to South Australia were not limited by constraints. The flows across Murraylink to South Australia were limited to avoid voltage collapse at Red Cliffs.

During the time of maximum demand, all DSN elements were loaded below their system normal ('n') limits. In system normal, the DSN element with highest n loading was Ballarat to Waubra 220 kV line, at 98%, followed by the Rowville A1 transformer, at 86% of its continuous rating.

[51] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/operational-demand-data.

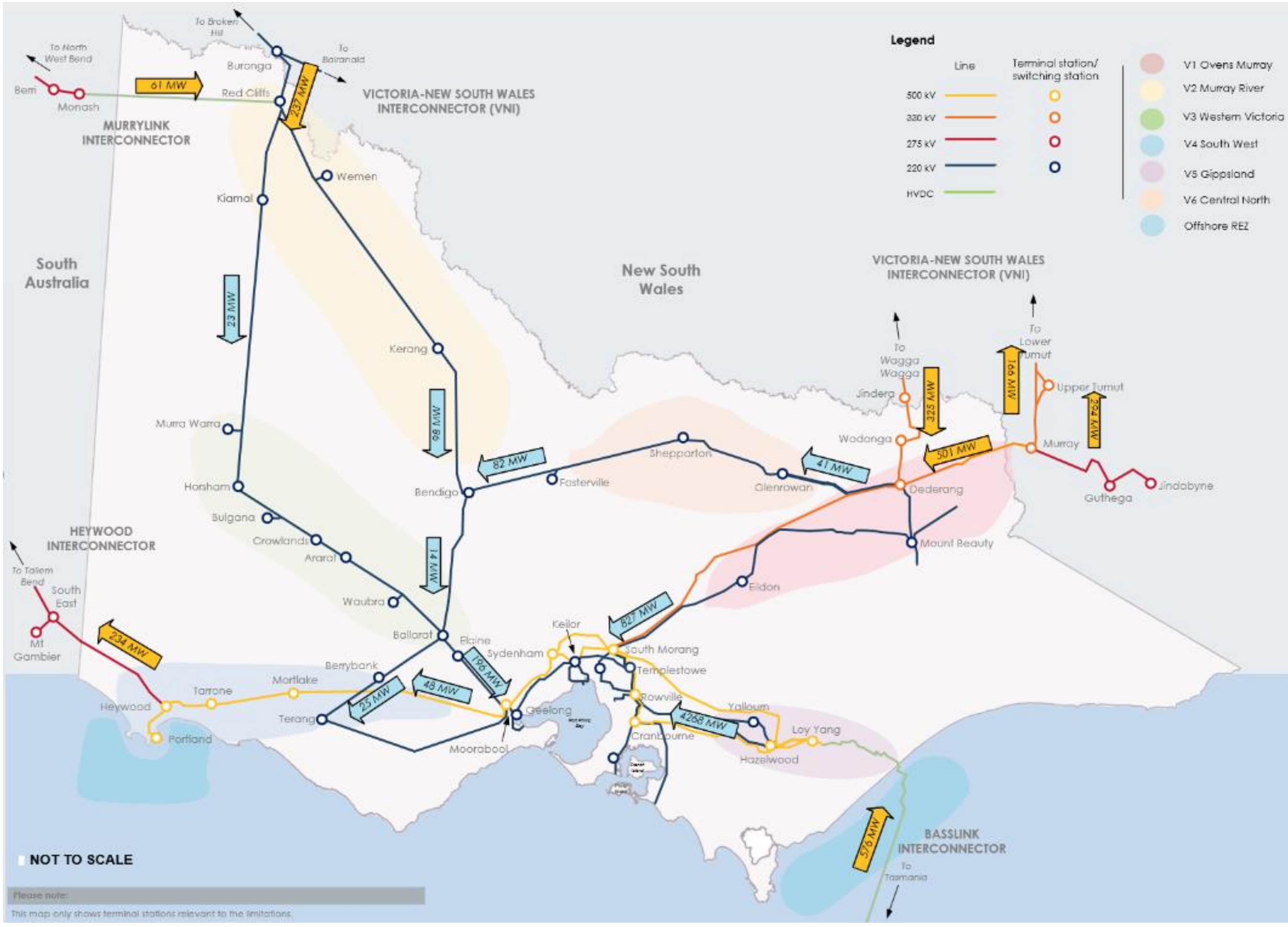
The DSN element with the highest modelled post-contingency ('n-1') loading was the Ballarat to Waubra 220 kV line, for the loss of Redcliff to Wemen to Kerang line. The second DSN element with highest modelled post-contingency ('n-1') loading was Deer Park to Geelong line, for the loss of Deer Park to Keilor line 1.

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[52].

In terms of bus voltages, Deer Park observed a potential low voltage risk for the outage of Deer Park to Keilor 220 kV line, which was later managed.

Figure 17 shows the direction and magnitude of power flows through significant DSN corridors during maximum demand, with greater Melbourne's 6.0 GW of load being primarily supplied via the Eastern Metro, with some supply via Northern Metro, and Western Metro corridors.

Figure 17 Map of power flows along significant corridors during maximum demand (16:00 on 22 February 2024)



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

4.3 Minimum demand condition

4.3.1 Daytime minimum demand snapshot

The daytime minimum demand snapshot captures conditions under which voltages need to be carefully controlled, as lightly loaded lines charge voltages towards the high end of their operating limits. Distributed and large-scale solar generators are 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 2.2.2).

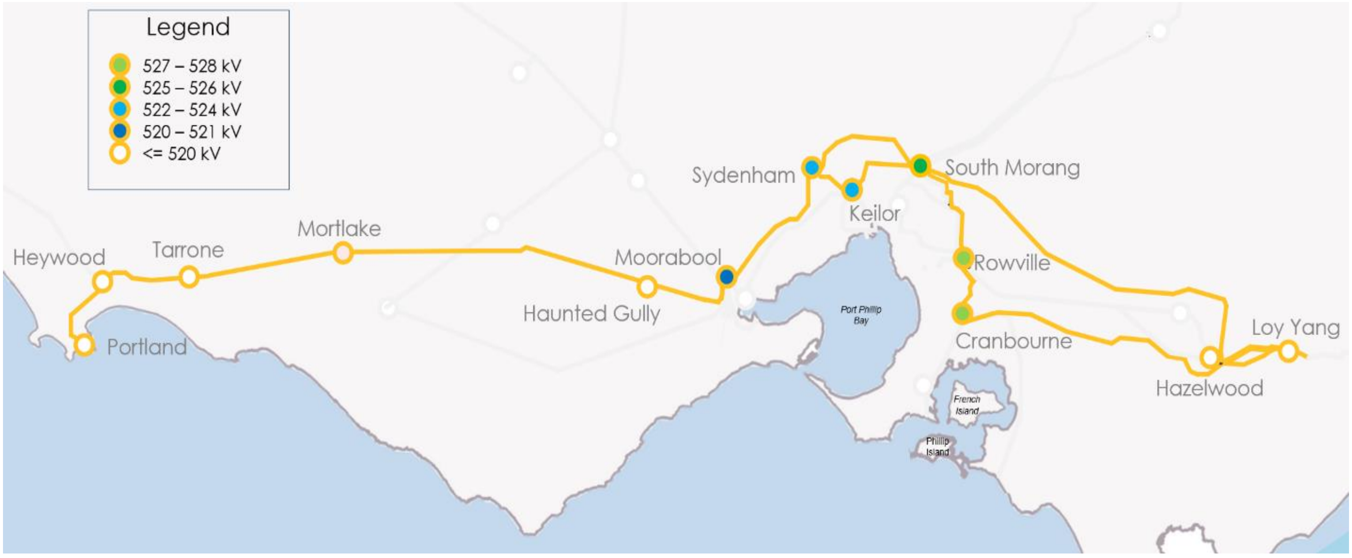
The minimum demand (1,564 MW) was observed at 13:00 on 31 December 2023. Some of the key observations are:

- Over 3 GW of distributed PV generation was observed at this time.
- Generation from majority of the larger-scale solar plants were curtailed due to network constraints.
- Several constraints were binding (V::N_HWSM_V1, V::N_NIL_O1, V^^V_NIL_KGTS, V^^V_NIL_KGTS_2).
- Non-scheduled WFs (Portland, Waubra Mercer) were also instructed to reduce their output to 0 MW.

During low demand in Victoria, operators have historically been required to take action to manage high voltages (see Section 2.3.2). The unavailability of conventional generators to absorb the excess reactive power during low demand periods may result in high voltages across the 500 kV and 220 kV Metropolitan Melbourne network (such as Keilor), and some of the 220 kV Victorian regional network. Hazelwood to South Morang 500 kV No. 1 line was out of service to manage voltages on this day.

Figure 18 shows a heat map of post-contingent (n-1) voltages across Victorian 500 kV terminal stations for a critical contingency. Voltages are higher than the nominal voltage of the terminal stations in and around the metropolitan load centres (like Rowville and Cranbourne). However, the voltages do not violate the post-contingency voltage limits at any of the terminal stations.

Figure 18 Post-contingency (Loy Yang unit outage) voltages at 500 kV terminal stations during daytime minimum demand



KTS typically sets the requirement for high voltage management, as its emergency high voltage rating is lower than other 500 kV terminal stations. On this day, the KTS over-voltage protection scheme (KTSOVPS) was initiated to increase the post-contingency high voltage limit (KVEM)[53] at the KTS 500 kV bus up to 535 kV for 30 minutes. The continuous rating (KVNO)[54] at the KTS 500 kV bus remained at 525 kV. Following the commissioning of the KTS No. 1 and No. 2 reactor, the KTS 500 kV over-voltage protection scheme remains armed, but is made operationally unavailable, that is, not available for normal voltage control actions. The KTSOVPS is scheduled to be upgraded with duplicated protection system (X and Y) by end of October 2024. Following completion of this upgrade, this scheme will be made operationally available permanently, thus the post-contingency high voltage limit of KTS 500kV bus will be increased to 535 kV (from 525kV) for security assessment/contingency analysis.

The snapshot is based on power system characteristics observed at 13:00 on 31 December 2023. At this time every interconnector except Heywood was exporting within its limit:

- Heywood was importing from South Australia and Murraylink was exporting towards South Australia at its limit, which was set by a thermal constraint avoiding overloading in northeast South Australia.
- VNI East was overall exporting at its limit, which was set by a system normal voltage collapse constraint for the trip of any major 220 kV line in Northwest Victoria. It was observed that the VNI constraint was violated for some intervals on that day, but the system was overall secured.
- Basslink was also exporting towards Tasmania at its limit, set by the system normal frequency control ancillary services (FCAS) constraints.

4.3.2 Night-time minimum demand snapshot

The night-time minimum demand scenario is characterised by no solar – quite different to the lowest minimum demand, which usually occurs in the middle of the day.

The lowest night-time operational demand in 2023-24 was 3,442 MW, which was 1,878 MW higher than the annual minimum demand that occurred in the daytime. The difference between daytime minimum demand and night-time minimum demand is increasing every year, as night-time minimum demand stays approximately the same while daytime minimum demand continues declining, reflecting the uptake of distributed PV.

In the minimum night-time operational demand case, Hazelwood to South Morang 500 kV No.1 line was de-energised to maintain the voltage. Rowville static VAR compensators (SVCs) regulate the voltage to the required set point by controlling the reactive power flow and to provide dynamic reactive power reserve for contingencies These SVCs were absorbing more than 40 MVAr on this instance. All Keilor and Moorabool reactors were in service and La Trobe Valley units were close to their minimum taps.

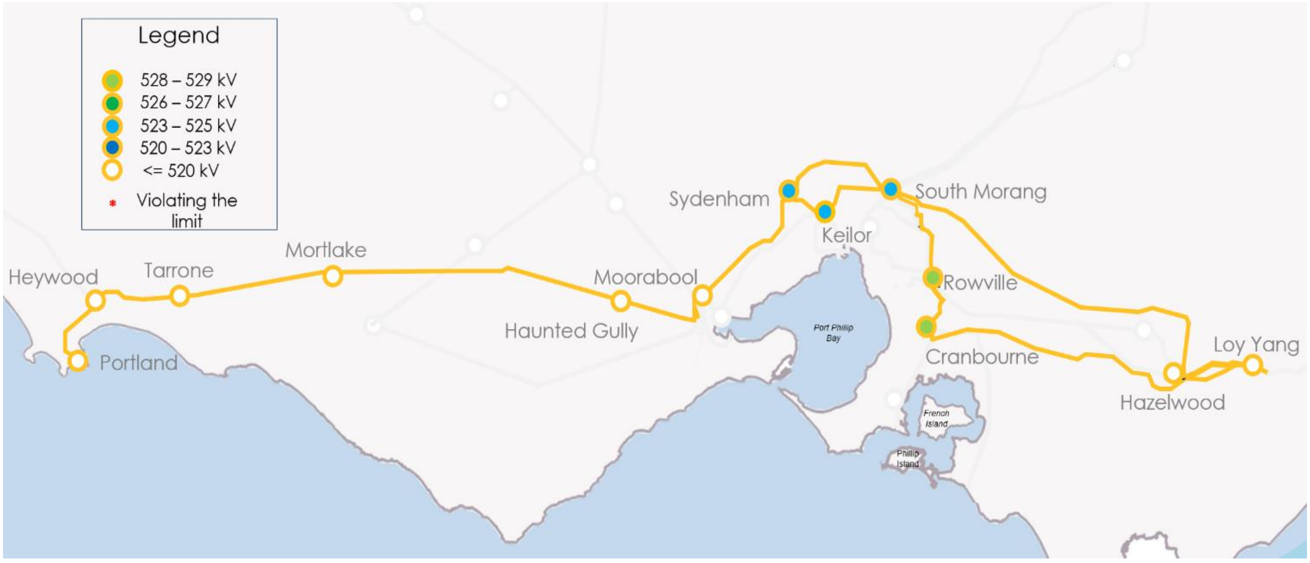
Figure 19 shows a heat map of post-contingent voltages across Victorian 500 kV terminal stations for a critical contingency. The post-contingent voltages across the 500 kV network are higher than or equal to those of the annual minimum demand snapshot. AVP is undertaking the Metropolitan Melbourne Voltage Management RIT-T to

[53] The KVEM levels define the post-contingent operating voltage range. This range is used in monitoring and control of equipment voltage level following a contingent event.

[54] The KVNO levels define the pre-contingent operating voltage range. This range is used in monitoring and control of equipment voltage level without considering contingent events.

identify the preferred option that will improve the voltage performance across the DSN following its implementation.

Figure 19 Post-contingency (Loy Yang unit outage) voltages at 500 kV terminal stations during night-time minimum demand



The snapshot is based on power system characteristics observed at 03:30 hrs on 25 December 2023. At this time:

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

4.4 High renewable snapshots

4.4.1 High wind snapshot

Wind generation in Victoria is primarily located in the V3-Western Victoria and V4-South West Victoria REZs. Typically wind generation from the two REZs is coincidental due to their geographical proximity. Maximum wind generation for 2023-24 in Victoria occurred at 18:00 on 30 May 2024.

Table 12 Summary of operating conditions for maximum wind generation in Victoria

Characteristic	Maximum demand
Date and time	30/05/2024 18:00
Victorian operational demand	6,868 MW
Distributed PV	0 MW
Net power flow into Victoria via interconnectors*	-1,026 MW • 602 MW to New South Wales • 25 MW from South Australia • 449 MW to Tasmania
Victorian renewable generation	3,258 MW, representing 44% of Victorian large-scale generation, consisting of • 3,258 MW of wind • 0 MW of Solar
Victorian synchronous generation	4,186 MW, representing 56% of Victorian large-scale generation, consisting of- • 4,105 MW of coal • 0 MW of gas • 81 MW of hydro
Temperature at Melbourne Airport	15.1°C

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

Victorian wind generation saw a 392 MW drop in the maximum wind generation output, compared to 2022-23. At the time of maximum wind, 1,806 MW (52%) of Victorian wind generation was supplied from the V4-South West Victoria REZ, and 1,323 MW (38%) of Victorian wind generation was supplied from the V3 Western Victoria REZ.

Figure 20 shows the pre-contingent (actual) loading and post-contingent loading (expected) 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 Kerang. It shows that at the time of maximum wind generation, none of the lines were operating at their post-contingent thermal limits. The Waubra to Ballarat line loaded 92% post-contingent for loss of Red Cliffs – Wemen – Kerang line.

This snapshot occurred at night when the thermal ratings of these critical lines were high due to the low temperatures (15.1°C at Melbourne Airport). During higher temperatures when the line ratings are lower, it is likely that these thermal constraints would have been more limiting and wind generation in Western Victoria constrained. WRL will reduce instances when generation is constrained by the Ararat to Waubra to Ballarat and Elaine to Moorabool 220 kV lines, while VNI West will reduce instances when generation is limited by the Ballarat – Bendigo 220 kV line in Western Victoria.

Figure 20 West Murray flows and loading, pre-contingent (left), post-contingent for loss of Red Cliffs – Wemen – Kerang (middle), post-contingent for loss of Horsham – Murra Warra – Kiamal (right)

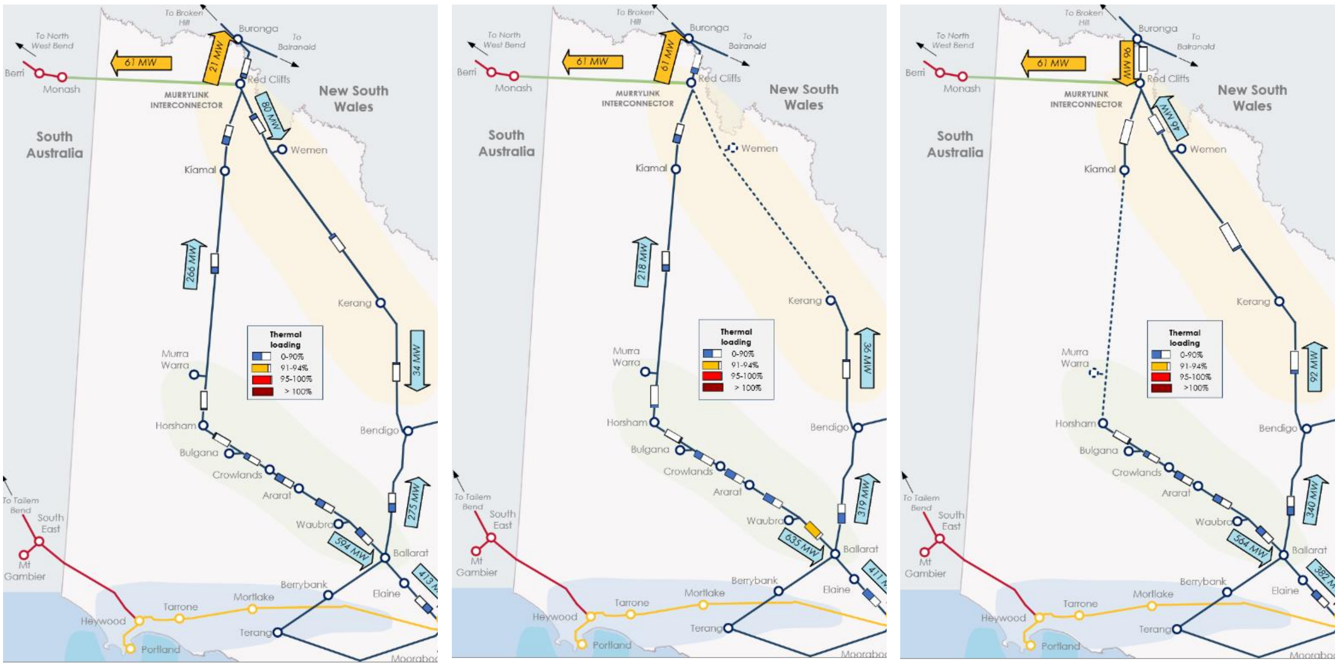


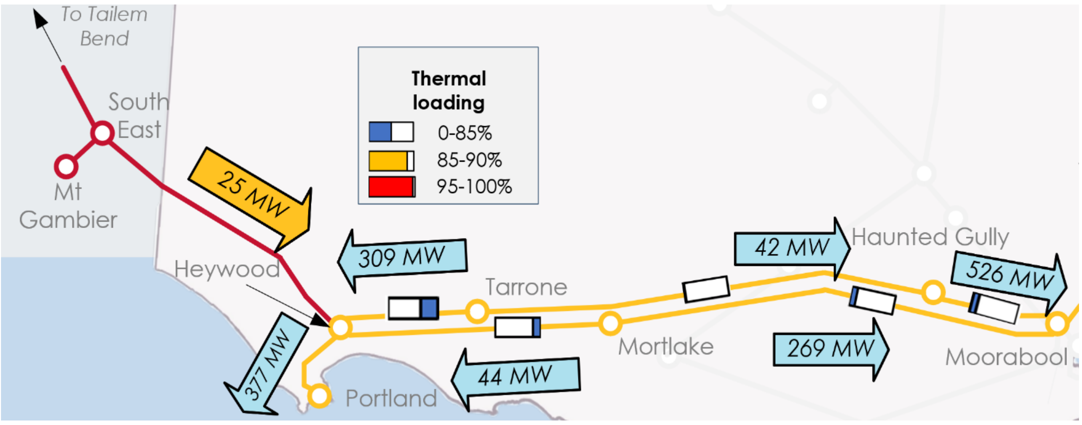
Table 13 shows the post-contingent loading and power flows from western Victoria and Murray REZs for loss of the Ballarat – Moorabool 220 KV line 2. It shows that during maximum wind generation, none of the lines were operating at or above their post-contingent thermal limits. The Waubra to Ballarat line and Elaine to Moorabool lines are loaded 89% and 88% respectively post-contingent for loss of the Ballarat – Moorabool 220 KV line 2.

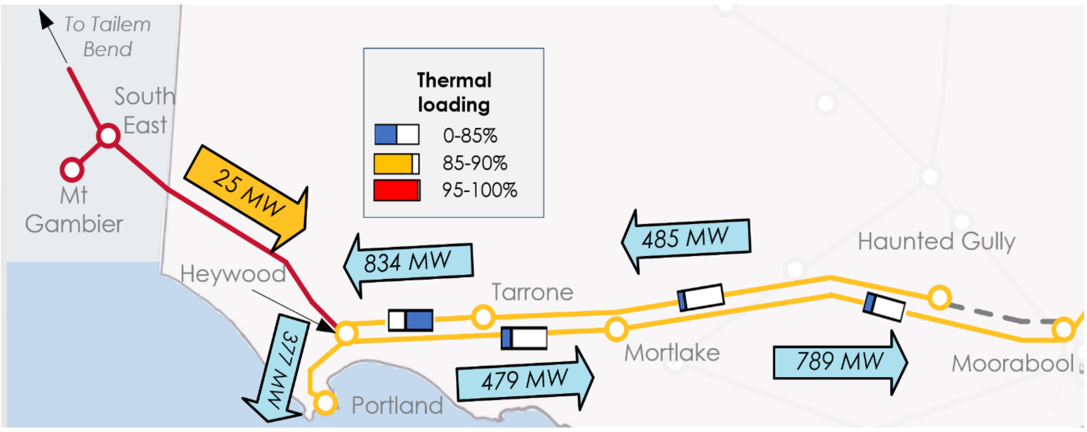
Table 13 Post-contingent flows from Western Victoria and Murray REZs for the loss of Ballarat – Moorabool 220 kV Line 2

Limiting constraint	220 kV lines of interest	% loading	MW flows
V>>NIL_ELML_BAML2	Waubra – Ballarat	89%	587
	Ararat – Waubra	64%	422
	Murra Warra – Kiamal	31%	273
	Red Cliffs – Buronga	7%	27
	Red Cliffs – Wemen	22%	80
	Ballarat – Bendigo	65%	294
	Elaine – Moorabool	88%	531
	Ballarat – Moorabool Line 1	66%	305

As shown in **Figure 21**, wind generation in the South West Victoria 500 kV network (V4-South West Victoria REZ) operated without impact from network constraints at this time.

Figure 21 500 kV flows and loadings V4-South West Victoria pre-contingent (above) and post-contingent (below) for Haunted Gully to Moorabool





4.5 High export snapshots

4.5.1 Maximum VNI export snapshot

VNI typically exports more often than it imports, and exports are currently most constrained by voltage collapse constraints (see Section 3.2.1). The high export snapshot summary in **Table 14** shows network operating conditions when VNI exports were highest.

Table 14 Summary of Victoria maximum export snapshot

Characteristic	Maximum demand
Date and time	09/07/2023 17:30
Victorian operational demand	6,487 MW
Distributed PV	4 MW
Net power flow into Victoria via interconnectors*	-1,252 MW • 1,186 MW to New South Wales • 489 MW to South Australia • 423 MW from Tasmania
Victorian renewable generation	2,587 MW, representing 34% of Victorian large-scale generation, consisting of:

Characteristic	Maximum demand
	• 2,587 MW of wind • 0 MW of Solar
Victorian synchronous generation	4,963 MW, representing 66% of Victorian large-scale generation, consisting of: • 4,337 MW of coal • 0 MW of gas • 626 MW of hydro
Temperature at Melbourne Airport	12.8° C

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

The VNI maximum export snapshot assesses the network conditions at 17:30 hrs on 9 July 2023, when VNI was dispatched at 1,186 MW. **Figure 22** below shows the flows, loading and voltages across the VNI Eastern corridor during the maximum export snapshot. The demand levels in both New South Wales and Queensland at this time were more than their generation, which led to export from Victoria through VNI East interconnector.

Figure 22 Maximum export flows, loading and voltages in the VNI Eastern corridor