2023 Network Support and Control Ancillary Services (NSCAS) Report

December 2023

A report for the National Electricity Market

Important notice

Purpose

The purpose of this publication is to summarise the Network Support and Control Ancillary Service gaps identified by AEMO over a five-year outlook period.

AEMO publishes this report in accordance with clause 5.20.3 of the National Electricity Rules. This publication is generally based on information available to AEMO as at October 2023 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	1/12/2023	Initial release.

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Executive summary

AEMO has identified new system security needs across the National Electricity Market (NEM) over the coming five years. Declining minimum operational demand, reduced operation of synchronous generators, and rapid uptake of variable renewable energy resources (VRE) have combined to create an increased need for essential power system services.

This report is part of a broader planning framework under the National Electricity Rules (NER) that works to ensure the power system can continue to operate securely and reliably as the energy transition continues at pace. The scope of change means there will be an inevitable need for network investment, and while network businesses can already act through their normal planning processes, AEMO's work to declare network support and control ancillary service (NSCAS) gaps remains an important safety net for power system security.

The energy transition is highlighting new challenges for maintaining system security

Australia is now installing solar and wind energy faster than at any time in history, and power system dynamics are increasingly influenced by the generation of millions of individual consumer energy resources (CER), such as rooftop solar photovoltaic (PV) systems. Patterns of power flow are changing quickly as generation moves behind the meter or to remote parts of the grid.

While the system was once able to operate well inside its technical envelope, the energy transition is pushing the system to operate more frequently near its boundaries. This has highlighted new security concerns in the short term while major network, generation, and energy storage projects deliver improvements in the longer term.

AEMO has explored a broad range of power system needs in the 2023 NSCAS report

To capture these emerging needs, the 2023 NSCAS Report explores a range of potential power system requirements over the next five years. It includes a regional assessment of the system's ability to maintain adequate reactive margins, to limit rapid voltage changes, and to provide sufficient options to return to a secure operating state following a credible contingency event. AEMO also recognises that the challenges facing each region are unique, so has included several region-specific studies that were scoped collaboratively with operators and network businesses.

This report also extends AEMO's previous 100% renewable penetration studies to consider high demand periods. The analysis confirms that system strength is likely to be the most onerous requirement, and notes that inertia needs could be met in tandem by solutions that deliver both services. The work also identifies that leveraging the reactive capabilities of new inverter-based resources (IBR) will be critical in meeting future voltage control needs.

AEMO has identified two new NSCAS gaps

The 2023 NSCAS assessment has confirmed that existing NSCAS gaps in Queensland and New South Wales have been closed, and has declared new gaps in Victoria and South Australia. Several marginal or emerging risks have also been identified and provided to relevant network businesses for further investigation.

A summary of regional findings is presented in Table 1, and AEMO will continue to work closely with the relevant network businesses on developing and tracking remediation plans associated with each.

Table 1 Summary of new and existing NSCAS gaps

Region	NSCAS gap
New South Wales 	**The existing NSCAS gap at Coleambally has been closed.** Transgrid has temporary operating measures in place and is progressing long-term remediation through a Regulatory Investment Test for Transmission (RIT-T). **AEMO notes a short-term voltage control need affecting network near Canberra, Yass, and Lower Tumut.** Credible contingencies can result in high and low voltage exceedances at these locations when no nearby hydro generating units are online, and in cases where Victoria is exporting at least 700 MW to New South Wales. This is an infrequent issue with temporary operating measures in place, and the underlying need is expected to be improved by committed projects by mid-2024.
Queensland 	**The existing NSCAS gap in Southern Queensland has been closed.** Powerlink has a network support agreement in place until January 2024 and have concluded a RIT-T for long-term remediation, which is expected in late 2024. Powerlink is progressing further interim arrangements to cover the intervening period.
South Australia 	**AEMO is declaring an NSCAS gap for voltage control in South Australia.** This draws on the latest limits advice from ElectraNet and clarifies a need to maintain synchronous generating units online for voltage control. ElectraNet is progressing a RIT-T which is expected to close this voltage control gap, and subsequently to allow operation with fewer synchronous generating units online once paired with Project EnergyConnect (PEC) and an adequate demonstration of grid reference in South Australia. AEMO will continue to work closely with ElectraNet to track progress and identify any additional options for acceleration or remediation.
Tasmania 	**AEMO has not identified any NSCAS gaps in Tasmania over the five-year period.** AEMO acknowledges that TasNetworks is procuring system strength and inertia services in response to requirements in those planning frameworks, and that these may support other power system security needs in the region.
Victoria 	**AEMO is declaring an NSCAS gap for thermal loading and voltage stability near Deer Park.** This relates to projected demand growth, and AEMO Victorian Planning (AVP) has committed to pre-feasibility work on the thermal limitations, while progressing voltage needs through its broader Metropolitan Melbourne Voltage Management RIT-T. **The NSCAS studies also identified an emerging risk for reliability of supply to Metropolitan Melbourne from early 2029.** This relates to transformer loading risks between the 500 kilovolts (kV) and 220 kV network, and it may require investment to maintain reliable supply during peak demand periods following closure of Yallourn Power Station. AEMO has developed an operational solution and will consider long-term remediation if required. More information is available in the 2023 *Victorian Annual Planning Report* (VAPR).

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1 Introduction

Network support and control ancillary services (NSCAS) are defined in the National Electricity Rules (NER) as services with the capability to control the active or reactive power flow into or out of a transmission network. They may be procured to address the following needs under NER 3.11.6(a):

- **Reliability and security ancillary services (RSAS)** – maintain security and supply reliability of the transmission network in accordance with the power system security standards and the reliability standard.
- **Market benefits ancillary services (MBAS)** – maintain or increase capability of the transmission network to maximise net economic benefits to all those who produce, consume or transport electricity in the market.

AEMO assesses the need for these services annually and declares NSCAS gaps where it identifies an unmet need. Gaps often relate to voltage control, system stability, and thermal limits, but can include other challenges faced in operating a secure power system. Inertia and system strength requirements are assessed separately from NSCAS needs.

The NER give transmission network service providers (TNSPs) primary responsibility for acquiring NSCAS (with or without a declared gap). AEMO may be required to procure NSCAS under its last resort planning functions but can only do so to meet the RSAS category of NSCAS needs.

Reliability and security ancillary services (RSAS)

To identify RSAS gaps, AEMO considers the ability of the power system to maintain a secure operating state during system normal conditions; that is, the ability of the system to land in a satisfactory operating state following a credible contingency or protected event. AEMO may also consider if the system can be quickly returned to a secure operating state following a credible contingency or protected event.

AEMO's NSCAS studies consider actions that can be taken by AEMO in real time to manage power system security, but also factor in future system changes such as committed or anticipated generation and transmission projects, announced generator retirements, and forecast changes in demand.

Market benefits ancillary services (MBAS)

To identify MBAS gaps, AEMO considers whether positive net market benefits could be delivered by relieving high-impact network constraints. AEMO reviews existing constraint statistics, to identify any constraints that bound for at least one hour in the previous calendar year and had a total marginal cost of at least $50,000. AEMO typically sources this information from the annual National Electricity Market (NEM) constraint report summary[1].

AEMO may also consider specific constraints nominated by participants or those forecast to be significant through other power system planning and operational activities, in alignment with the NSCAS description and quantity procedure[2].

[1] AEMO. NEM Constraint Report 2022 summary data. 24 May 2023, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2022/nem-constraint-report-2022-summary-data.xlsx?la=en.

[2] AEMO. NSCAS description and quantity procedure, version 2.2. December 2021, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

1.1 Trends impacting NSCAS assessments

The NEM is changing at a speed and scale never before seen, transforming the way electricity is generated, transported, and consumed. The pace of this change is still accelerating, and traditional ways of operating are being challenged as system security and reliability become increasingly complex.

As the system moves away from a historical dependence on synchronous generation, the energy future is expected to be built on low-cost renewable energy, dynamic firming technology, new network infrastructure, and adaptive operating strategies. This shift will have a significant impact on the severity and timing of NSCAS needs, and AEMO is reflecting that through a broader scope of studies conducted for the 2023 NSCAS Report.

Inverter-based resource connections can provide reactive power capability that helps control network voltages

Australia is now installing renewable energy faster than at any time in history. At the same time, power system dynamics are increasingly influenced by the generation of millions of individual consumer energy resources (CER) systems. In recent years, many of the declared NSCAS gaps have related to voltage management, driven largely by declining minimum demands and changing power flow patterns. While those trends will continue, AEMO's NSCAS studies are increasingly finding that new utility-scale inverter-based resources (IBR) can provide additional reactive power capabilities that improve voltage control in the system. The 2023 NSCAS studies have therefore expanded beyond traditional voltage management studies when assessing newly emerging gaps over the next five years.

The growth of consumer energy resources is increasing the magnitude of ramping events and network contingencies

The rapid uptake of weather-dependent CER has also created new security risks associated with ramping events (where weather patterns produce a sudden change in the demand seen by the transmission network), and in the size of credible contingencies (where CER may trip sympathetically and increase the impact of a nearby network event). While these challenges are being managed operationally, their effects will continue to grow. AEMO has performed a near-term exploratory analysis of ramping risks as part of the 2023 NSCAS report.

Withdrawal of synchronous generation also is impacting network capability and security

Many critical system security needs were once met by the natural properties of a synchronous generation fleet. These were typically located in centralised locations, were coupled with predictable demand patterns, and allowed the power system to operate comfortably inside its technical envelope. However, the energy transition is pushing the system to operate closer to its boundaries, highlighting new concerns for maintaining reactive margins, ensuring manageable voltage step changes, and re-establishing a secure system following a contingency event. AEMO has explored each of these in more depth as part of the 2023 NSCAS report, including several region-specific studies identified collaboratively with the regional network businesses.

System strength and inertia are also impacted by changes in the generation fleet, but those requirements sit outside the scope of the NSCAS framework. However, any system strength or inertia solutions may also provide incidental system support that potentially reduces NSCAS needs. The 2023 NSCAS report extends AEMO's previous 100% renewable penetration studies to cover high demand conditions, and explores several investment interactions between the three security planning frameworks.

1.2 Scope of analysis

This report represents AEMO's 2023 assessment of NSCAS gaps under NER 5.20.3 and covers the five-year period from 2024 to 2028 inclusive. The underlying analysis considers a range of power system requirements, as summarised below. All assessments have been conducted in accordance with the latest NSCAS procedures[3], and are based on the latest available data for committed, anticipated, and actionable ISP projects; committed and anticipated generation; announced generator retirements; and forecast changes in demand.

Contingency analysis

Contingency analysis simulates the state of a power system following a credible contingency event. This type of study is typically used to identify network elements where thermal ratings or voltage limits are exceeded. In the NSCAS context, contingency events are applied independently to an initially secure power system, and the results are monitored to confirm that no single credible event would cause limit violations.

Reactive margin

Reactive margins indicate the additional reactive loading that could be applied at a network location before it would result in voltage collapse. Low levels of reactive margin indicate that the system is at greater risk of such collapse, and low reactive margins could exist even when absolute voltages appear normal. In the NEM, reactive margins are required to remain above 1% of the maximum fault level at each connection point, and AEMO has applied this standard when assessing NSCAS needs in each region.

Rapid voltage change

When reactive power devices are switched in or out of service on the network, nearby voltage levels are impacted. The size of these impacts can vary over time as generation and network loading patterns change. Acceptable levels of voltage change depend on the number of switching events that occur in each period. AEMO has assumed the most onerous system standard of 2.5% when screening these outcomes, however a higher standard of 5% can also be applied for infrequent events.

Resecure risk

While contingency analysis confirms whether the power system lands in a satisfactory state for a single contingency, it does not consider what subsequent options are available to prepare the system for a further credible contingency or protected event. AEMO takes reasonable actions to achieve this, which might require redispatch, network reconfiguration, load shedding, or directions. The 2023 NSCAS assessment has considered these risks for several critical events, as identified with the system operators and the network businesses.

Region-specific and NEM-wide studies

AEMO also recognises that the challenges facing each region are often unique, so has included several region-specific studies that were identified through operational experience over the past year. In addition, this report extends AEMO's previous 100% renewable studies to consider maximum demand conditions.

[3] AEMO. NSCAS description and quantity procedure, version 2.2. December 2021, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

1.3 Structure of this report

The 2023 NSCAS report contains the following information:

- For each region, AEMO's assessment of NSCAS needs and gaps:
  - New South Wales (Section 2.1).
  - Queensland (Section 2.2).
  - South Australia (Section 2.3).
  - Tasmania (Section 2.4).
  - Victoria (Section 2.5).
- Analysis of security risks for high renewable penetration under maximum demand conditions (Section 3).
- An overview of next steps related to 2023 NSCAS findings (Section 4).
- An overview of the methodology and inputs used to prepare this report (Appendix A1).

The NSCAS assessment is primarily conducted on a regional basis, and AEMO recognises that most readers will focus on a region of interest, rather than reading all chapters sequentially, so each regional section has been prepared to allow it to be easily extracted or read in isolation from the others.

1.4 Summary of NSCAS contracts

AEMO has had no active NSCAS contracts during the past 12 months under its last resort planning functions. Table 2 notes the NSCAS service costs accrued by AEMO over the past five years.

Table 2 NSCAS services costs from financial year 2018-2019 to 2022-2023

Facility	NSCAS Service	Size (MVAr)	NSCAS contract end date	Annual cost				
				2018-19	2019-20	2020-21	2021-22	2022-23
Combined Murray and Yass substations	Voltage Control Ancillary Service [A] (VCAS)	800 [B]	30 June 2019	$10,572,619	$0	$0	$0	$0

MVAr: megavolt-amperes reactive.
A. NSCAS procured under the previous NSCAS types developed in 2011.
B. The maximum capacity available from this service.

2 NSCAS assessment

2.1 New South Wales

AEMO has confirmed the existing RSAS gap of 2 megavolts-amperes reactive (MVAr) reactive power absorption in the Coleambally area. Transgrid has temporary operating measures in place to manage this gap and is progressing long-term remediation through a regulatory investment test for transmission (RIT-T). AEMO considers that this gap is closed but will continue to monitor its status.

AEMO has identified a voltage control need on the 330 kilovolts (kV) network near Canberra, Yass, and Lower Tumut. This occurs at times when no nearby hydro generating units are online and Victoria is exporting at least 700 megawatts (MW) to New South Wales. Operational measures are already in place, and committed projects are expected to reduce this need by mid-2024.

Scope of assessment

AEMO has assessed NSCAS needs in New South Wales over a five-year outlook period. The existing voltage control gap for New South Wales was also reviewed, however other low demand scenarios have not been reassessed because newly committed and anticipated projects have improved expected voltage control outcomes since minimum demand studies were last conducted in December 2022.

Table 3 provides an overview of the core scenarios studied for New South Wales. These are based on committed, anticipated, and actionable transmission projects; committed and anticipated generation; announced generator retirements; and forecast changes in demand. In consultation with Transgrid, two sensitivity studies were also considered with a reduced renewable generation availability. Appendix A1 provides further detail on the specific input sources, modelling assumptions, and study methodologies used for the 2023 NSCAS assessment.

Table 3 New South Wales NSCAS scenarios and outcomes

Case	Project assumptions	Year	NSCAS gap
Low demand	High import from Victoria, no nearby hydro units online	2022-23	New voltage control RSAS need
High demand	Committed projects only	2023-24	No new gaps identified
	Committed projects only	2028-29	No new gaps identified
	Committed and anticipated	2028-29	No new gaps identified
	Committed projects (with lower wind and solar)	2023-24	No new gaps identified
	Committed and anticipated (with lower wind and solar)	2028-29	No new gaps identified

Note: While core studies were based on 2022 ESOO demand projections, sensitivity studies were also conducted with the updated 2023 ESOO demand forecasts. While the increased maximum demand forecasts for New South Wales do place greater pressure on voltage control around Sydney by the end of the study horizon, no new gaps have been identified. These results are highly sensitive to changes in anticipated project timing and location, so AEMO will continue to monitor emerging needs through future NSCAS assessments.

Status of the existing reliability and security ancillary services gap at Coleambally

AEMO has confirmed the previously declared RSAS gap of 2 MVAr reactive power absorption at Coleambally during minimum demand periods. This gap was first declared in AEMO's 2021 System Security Reports.

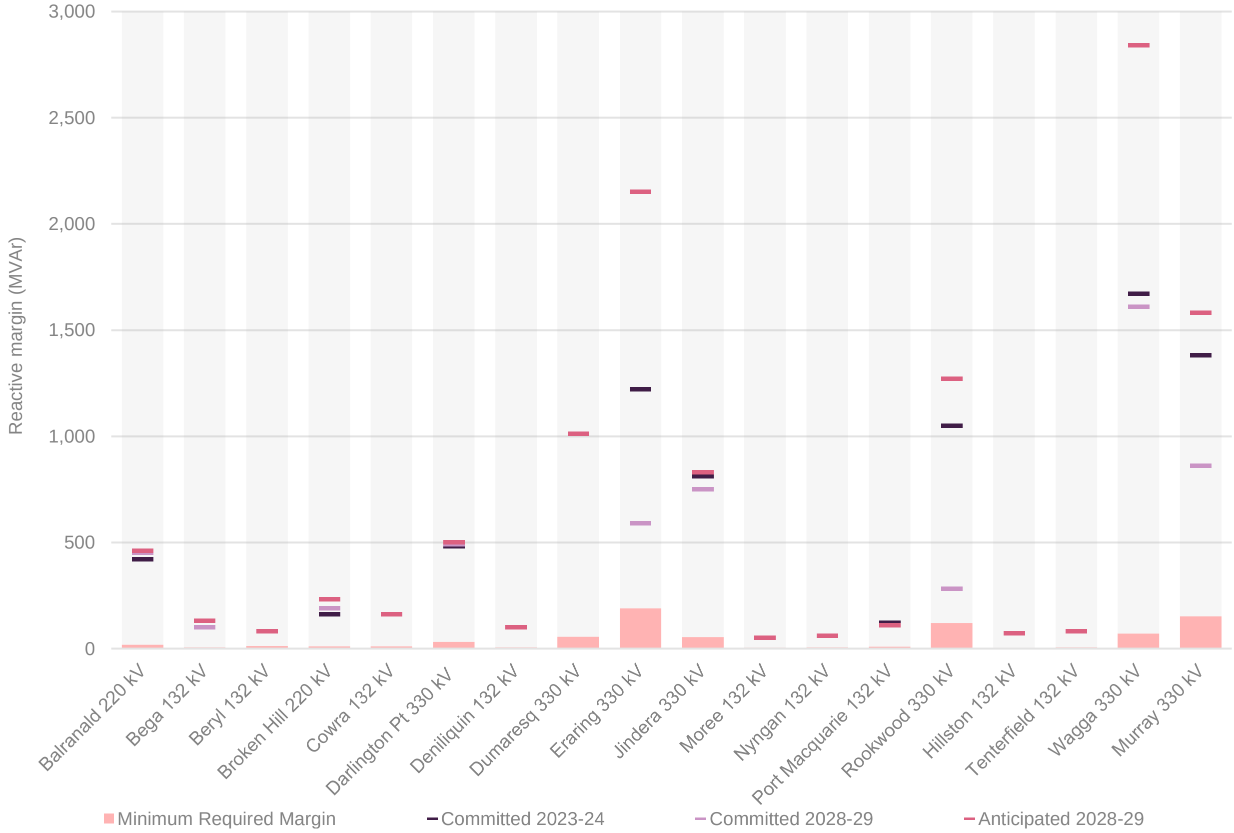
Transgrid has temporary operating measures in place to address this gap and is progressing a RIT-T to resolve broader voltage control challenges in the Deniliquin, Coleambally, and Finley areas[4]. That work recommends installation of two 11 MVAr 66 kV reactors at Deniliquin substation, with commissioning expected by 2025-26.

AEMO considers that this gap is closed but will continue to monitor its status.

Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in New South Wales are expected to remain above the system standard[5] of 1% of the local maximum fault level over the five-year outlook period. Figure 1 summarises the results of this analysis, which indicates that all reactive margins remain above the system standard.

Figure 1 Minimum reactive margin (MVAr) observed for critical buses in New South Wales



Note: While not shown here, results from the sensitivity cases were consistent with these results, and no reactive margin shortfalls were seen.

4 Transgrid PACR, at https://www.transgrid.com.au/media/clcksmaw/transgrid-pacr_maintaining-reliable-supply-to-deniliquin-coleambally-and-finley-area_24-feb-2023.pdf.

5 Required reactive margin is defined by NER S5.1.8 as "*not less than 1% of the maximum fault level (in MVA) at the connection point*". For the purposes of this assessment, the required reactive margin was calculated based on the 2023-24 maximum fault level.

Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in New South Wales. Table 4 summarises the results of this analysis, which indicate that all outcomes remain within the system standard[6].

While the studies identified some deviations exceeding the most onerous standard of 2.5% nominal voltage, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the Australian Standard.

Table 4 Rapid voltage change results for reactive plant switching in New South Wales

Case	Project assumptions	Year	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant
Maximum demand	Committed projects only	2023-24	2.9%	Armidale 132 kV	120 MVAr capacitor at Armidale 132 kV
	Committed projects only	2028-29	3.0%	Canberra 132 kV	120 MVAr capacitor at Canberra 132 kV
	Committed and anticipated	2028-29	2.9%	Armidale 132 kV	120 MVAr capacitor at Armidale 132 kV
	Committed projects sensitivity (with lower wind and solar availability)	2023-24	3.7%	Chullora 132 kV	120 MVAr reactor at Mason Park 132 kV
	Committed and anticipated sensitivity (with lower wind and solar availability)	2028-29	2.8%	Canberra 132 kV	120 MVAr capacitor at Canberra 132 kV

Voltage control risks around Canberra – Yass

AEMO has investigated simultaneous high and low voltage control challenges in New South Wales, during periods where no nearby hydro generating units are online and Victoria is exporting above 700 MW into the state. These challenges were identified through operational observations on 6 January 2023, and AEMO's 2023 NSCAS studies indicate that, under these conditions:

- Loss of all potlines at Alcoa Portland (APD) causes post-contingent low voltages at the Canberra and Yass 330 kV substations.
- Loss of the Wagga to Darlington Point 330 kV line results in post-contingent high voltages at the Lower Tumut 330 kV substation. This contingency also intertrips the Darlington Point to Balranald 220 kV line, and triggers runbacks on several wind and solar farms in the area.

These outcomes are highly sensitive to changes in power flows on the Victoria – New South Wales Interconnector (VNI), and this currently requires close monitoring by AEMO operations, and frequent switching of fixed shunt devices at Murray and Yass. AEMO considers that this presents a voltage control need in Southern New South Wales, which may require ±100 to 200 MVAr of dynamic reactive support. The associated system conditions occur infrequently, and temporary operating measures are currently in place.

This need is expected to further reduce by mid-2024, in response to additional reactive capabilities available from the committed Walla Walla solar farm and Capital Battery projects. Project EnergyConnect may also provide further improvements during its staged commissioning. AEMO will work closely with Transgrid to monitor the effectiveness of the temporary operating measures, and any changes in response to committed projects.

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

Voltage stability risks on loss of line 63

When Line 63 (the 330 kV transmission line between Darlington Point and Wagga) trips, a series of automated control schemes activate to trip multiple solar farms, wind farms and local transmission lines. AEMO investigated potential voltage stability risks following this contingency.

In particular, AEMO assessed reactive margins in the south-west of New South Wales and north-west of Victoria, under a range of historical cases where either Line 63 had tripped, or there were high transfers on Line 63 that would maximise the impact of such a trip. These studies did not identify any reactive margins outside the system standards under these system conditions.

AEMO also reviewed the magnitude of rapid voltage changes for several of the highest impact scenarios selected above. While most studies did not identify any values above 2.5%, AEMO did identify some as high as 3.5% when switching either of the Darlington Point 33 kV reactors if the Coleambally Solar Farm is out of service. While these are high, they remain within the 5% tolerance for infrequent events.

Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in New South Wales. Table 5 provides a comparison of binding hours and marginal values for the highest impact constraints observed[7]. All constraints with a marginal value exceeding $50,000 per year have been discussed with Transgrid, which has confirmed the status, project, control scheme, or other mitigation strategy applicable or underway for each. These constraints are being monitored through Transgrid's annual Transmission Annual Planning Report (TAPR) process.

Table 5 New South Wales high-impact constraint summary

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
N>NIL_94T	Avoid thermal overload on Molong to Orange North line	$27M (↑$15M)	1,596	Expected to be addressed by RIT-T: Increasing capacity for generation in the Molong and Parkes area.
N>NIL_969	Avoid thermal overload on Gunnedah to Tamworth line	$16M (↑$13M)	1,256	A future contingent project is being considered to address local issues driven by load growth, which involves the rebuild of 969 line to double circuit, which would address this constraint
N>NIL_94K_1	Avoid thermal overload on Wellington West to Wellington line	$9M (↑$9M)	865	Affects generators connected to the 94K line and in the Parkes region. Options include connecting Wellington West to Wellington via a new circuit, or a double circuit rebuild of the existing line.
N>NIL_9R6_9R5	Avoid thermal overload on Wagga North to Wagga 132 kV line on trip of Wagga North to Wagga 330 kV line.	$3M (↑$3M)	278	A new RIT-T project is being planned, likely to start in Q1 2024.
N>NIL_94T_947	Avoid thermal overload on Molong to Orange North line on trip of Wellington to Orange North line	$0.7M (↓$1M)	90	Expected to be addressed by RIT-T: Increasing capacity for generation in the Molong and Parkes area.

Note: From annual NEM Constraint Report, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been further prioritised on data to July 2023.

[7] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the NSCAS Description and Quantity Procedure: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en.

2.2 Queensland

AEMO has confirmed the existing RSAS gap of 120 MVAr reactive power absorption in Southern Queensland. Powerlink has a network support agreement in place until January 2024, and have concluded a RIT-T to deliver remediation from late 2024.

AEMO considers that this gap is closed until January 2024, at which time the gap reopens until the longer-term solution is in place. Powerlink is progressing further interim arrangements cover the intervening period.

The magnitude of this gap is sensitive to new generation and storage projects that may provide additional sources of reactive support. AEMO will continue to monitor this gap in the context of these projects.

Scope of assessment

AEMO has assessed NSCAS needs in Queensland over a five-year outlook period. The existing voltage control gap in Southern Queensland was also reviewed, however other low demand scenarios were not reassessed because newly committed and anticipated projects have improved expected voltage control outcomes since minimum demand studies were last conducted in December 2022.

Table 6 provides an overview of the core scenarios studied for Queensland. These are based on committed, anticipated, and actionable transmission projects; committed and anticipated generation; announced generator retirements; and forecast changes in demand. Appendix A1 provides further detail on the specific input sources, modelling assumptions, and study methodologies used for the 2023 NSCAS assessment.

Table 6 Queensland NSCAS scenarios and outcomes

Case	Project assumptions	Year	NSCAS gap
High demand	Committed projects only	2023-24	No new gaps identified
	Committed projects only	2028-29	No new gaps identified
	Committed and anticipated	2028-29	No new gaps identified

Note: While core studies were based on 2022 ESOO demand projections, screening studies were conducted to confirm potential impacts of higher demand in Queensland as forecast in the 2023 ESOO. This increase in forecast demand could put extra pressure on voltage control in and around southern Queensland by the end of the horizon, however this is very sensitive to changes in anticipated projects. AEMO will continue to monitor this, and update in future NSCAS studies.

Status of existing NSCAS gap

AEMO has confirmed the previously declared RSAS gap in Southern Queensland of 120 MVAr reactive power absorption. This gap was first declared in AEMO's 2021 System Security Reports.

In March 2023, Powerlink confirmed it had executed a network support agreement to close this NSCAS gap until at least January 2024, with an option to extend. This arrangement allows operators to access additional reactive absorption services between midnight and 7.00 am if required. Further operational measures are in place to manage voltages during periods where the service is not available.

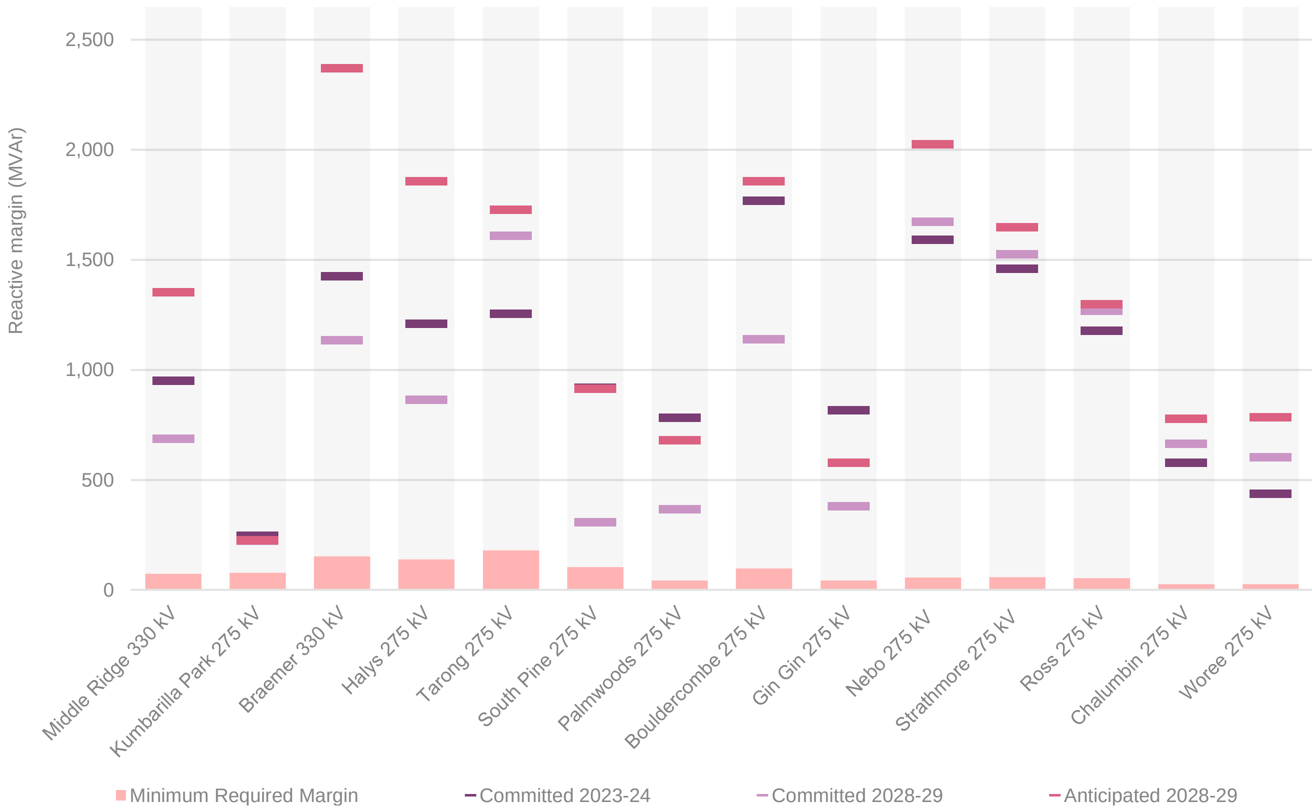
While the network support agreement is only a temporary arrangement, Powerlink has now assessed longer-term solutions to meet these needs through its RIT-T on Managing Voltages in South East Queensland[8]. The preferred investment option is the installation of a 120 MVAr bus reactor at Belmont Substation, and Powerlink expects this reactor will be available for service by late 2024.

AEMO therefore considers that the existing gap is closed until January 2024, at which time the gap reopens until the longer-term solution is in place. Powerlink is progressing further interim arrangements to address this gap for the intervening period. The magnitude of this gap may reduce as new generation and storage projects connect and provide additional sources of reactive support. AEMO will continue to monitor this gap in the context of these project changes.

Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in Queensland are expected to remain above the system standard [9] of 1% of the local maximum fault level[10] over the five-year outlook period. Figure 2 summarises the results of this analysis, which indicates that all reactive margins remain above the system standard.

Figure 2 Minimum reactive margin (MVAr) observed for critical buses in Queensland



[8] See https://www.powerlink.com.au/managing-voltages-south-east-queensland.

[9] Required reactive margin is defined by NER S5.1.8 as "*not less than 1% of the maximum fault level (in MVA) at the connection point*". For the purposes of this assessment, the required reactive margin was calculated based on the 2023-24 maximum fault level.

[10] Derived from indicative short circuit current at Powerlink's 2022 TAPR, Appendix E, at https://www.powerlink.com.au/reports/transmission-annual-planning-report-2022.

Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in Queensland. Table 7 summarises the results of this analysis, which indicate that all outcomes remain within the system standard[11,12].

Table 7 Rapid voltage change results for reactive plant switching in Queensland

Case	Project assumptions	Year	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant
Maximum demand	Committed projects only	2023-24	2.4%	Cooroy 132 kV	50 MVAr capacitor at Cooroy 132 kV
	Committed projects only	2028-29	2.9%	Boyne Island 132 kV	90 MVAr capacitor at Boyne Island 132 kV
	Committed and anticipated	2028-29	2.7%	Newlands 132 kV	26 MVAr capacitor at Newlands 132 kV

Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Queensland. Table 8 provides a comparison of binding hours and marginal values for the highest impact constraints observed[13]. All constraints with a marginal value exceeding $50,000 per year have previously been discussed with Powerlink, and they have confirmed the status, project, control scheme, or other mitigation strategy applicable for each. These options are being monitored through Powerlink's annual TAPR process and may trigger action if market benefits exceed remediation costs.

Table 8 Queensland high-impact constraint summary

Constraint ID	Description	Marginal Value (↓↑ change)	Binding Hours	TNSP Comments
Q>NIL_EMCM_6056	Avoid thermal overload on Emerald to Comet 66 kV Feeder	$8M (↑ $2M)	952	Energy Queensland is progressing projects to assist with this constraint.
Q>NIL_YLMR	Avoid thermal overload on 110 kV feeders between Yarranlea and Middle Ridge	$5M (↑ $4M)	594	Energy Queensland has existing runback schemes on the nearby solar farms to manage loading on these lines.
Q>NIL_757_758_ECS	ECS for managing Mudgeeraba to Terranora 110 kV lines	$1M (↑ $1M)	41	Unlikely to provide enough market benefit to justify augmentation. Increased transfer between New South Wales and Queensland being delivered through Queensland – New South Wales Interconnector (QNI) minor upgrades.
Q>NIL_EMBW_EMLV_DS	Limit Emerald SF to 40 MW to avoid overload on Emerald – Lilyvale 66 kV line for trip of Emerald - Comet - Blackwater 66 kV line	$0.6M (↑ $0.4M)	141	Energy Queensland is progressing projects to assist with this constraint.

Note: from annual NEM Constraint Report: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been further prioritised on data to July 2023.

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

[12] Queensland has a derogation 9.37.12 to use AS2279 to plan for voltage step changes.

[13] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the Description and Quantity Procedure: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en

2.3 South Australia

AEMO is declaring an immediate RSAS gap for voltage control in South Australia. This draws on the latest limits advice from ElectraNet relating to voltage control requirements at times of low demand, and when specific network assets are out of service.

ElectraNet is currently progressing a voltage control RIT-T which is expected to close this gap in parallel with commissioning of Project EnergyConnect (PEC). While voltage control is a factor in the current need for synchronous generator unit-commitment in South Australia, addressing this need in isolation is unlikely to result in a zero-unit requirement until PEC has been fully commissioned, and adequate grid reference testing has been conducted.

AEMO will work closely with ElectraNet to monitor remediation activities, and to identify any options for acceleration or additional remediation.

Scope of assessment

AEMO has assessed NSCAS needs in South Australia over a five-year outlook period. A region-specific low demand study was also performed based on recent limits advice from ElectraNet, however other low demand scenarios have not been reassessed as part of the 2023 NSCAS scope because there have not been any material changes expected to have worsened voltage control outcomes since minimum demand studies were last conducted in December 2022.

Table 9 provides an overview of the core scenarios studied for South Australia. These are based on committed, anticipated, and actionable transmission projects; committed and anticipated generation; announced generator retirements; and forecast changes in demand.

Appendix A1 provides further detail on the specific input sources, modelling assumptions, and study methodologies used for the 2023 NSCAS assessment.

Table 9 South Australian NSCAS scenarios and outcomes

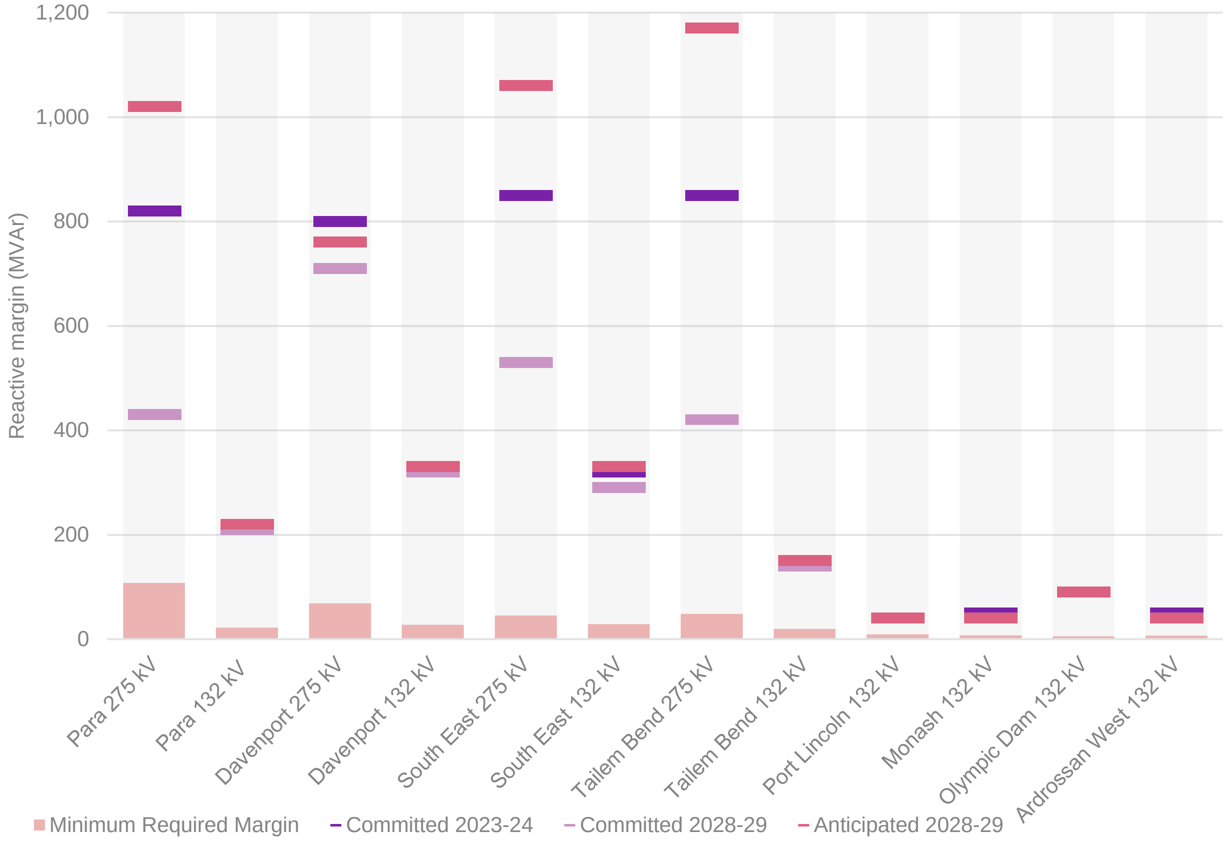
Case	Project assumptions	Year	NSCAS gap
Low demand	Committed projects only, PEC not yet in service, demand less than 600 MW.	2022-23	New voltage control RSAS gap for low demand
High demand	Committed projects only, PEC Stage 1	2023-24	No new gaps identified
	Committed projects only, PEC in service	2028-29	No new gaps identified
	Committed and anticipated, PEC in service	2028-29	No new gaps identified

Note: While core studies were based on 2022 ESOO demand projections, additional sensitivities were conducted to confirm any potential impacts from the revised 2023 ESOO projections. No material change impacting these results were identified.

Reactive margin

AEMO assessed the system normal and post-contingent reactive margins at critical buses in South Australia. Figure 3 summarises these results and indicates that all reactive margins remain above the system standard[14].

Figure 3 Minimum reactive margin (MVAr) observed for critical buses in South Australia



Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in South Australia. Table 10 summarises the results of this analysis, which indicate that all outcomes remain within the most onerous system standard of 2.5% nominal voltage[15].

Table 10 Rapid voltage change results for reactive plant switching in South Australia

Case	Project assumptions	Year	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant
Maximum demand	Committed projects only	2023-24	1.2%	Bundey 330 kV	60 MVAr reactor at Bundey 330 kV
	Committed projects only	2028-29	1.9%	Black Range 275 kV	100 MVAr capacitor at Tailem Bend 275 kV
	Committed and anticipated	2028-29	1.1%	Happy Valley 275 kV	100 MVAr capacitor at Happy Valley 275 kV

[14] Required reactive margin is defined in NER S5.1.8 as "*not less than 1% of the maximum fault level (in MVA) at the connection point*". For the purposes of this assessment, the required reactive margin was calculated based on the 2023-24 maximum fault level.

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

Voltage control challenges in South Australia

Since November 2021, South Australia has been operated with a minimum requirement of two large synchronous generators online. This represented a reduction from previous levels, following commissioning of four new synchronous condensers in the region to address a more onerous system strength requirement.

In June 2023, ElectraNet provided a revised set of limits advice that considers system operation with fewer synchronous generators online. As part of this advice, ElectraNet stipulated that operation with a single synchronous generating unit is only possible when a specific set of voltage controls conditions are met – including demand above 600 MW, a set of specific reactive power control devices available, at least one 275 kV-connected synchronous generator online, and no credible risk of South Australia separating from the NEM.

The advice confirms that voltage control is one factor driving the current two generating unit requirement in South Australia; and that this may be relaxed to a one-unit requirement under certain conditions where additional voltage control measures are met, and fast-start resecure options are available to in the region. Addressing this need in isolation is unlikely to result in a zero-unit requirement until PEC Stage 2 has been commissioned, and adequate grid reference testing has been conducted.

However, AEMO has modelled this latest limit advice from an NSCAS perspective and confirms that a voltage control need does exists in South Australia when operating with fewer than two synchronous generating units online. As the need is unmet, and it exists within the five-year NSCAS period, AEMO is declaring an ongoing RSAS gap of 200 MVAr[16] during periods when South Australian demand is below 600 MW, and South Australia is not islanded or at credible risk of islanding[17].

AEMO has engaged with ElectraNet ahead of this publication to understand the timing and actions being taken to address this need. AEMO acknowledges that ElectraNet is currently progressing a voltage control RIT-T[18] which is expected to close this declared gap in parallel with PEC commissioning. The initial phase of the RIT-T also included an invitation seeking non-network service providers. In addition, ElectraNet has previously undertaken market testing for unit-commitment services to address both System Strength and Inertia shortfalls in South Australia. These assessments did not identify any synchronous services able to satisfy both technical and economic considerations.

On this basis, AEMO considers that reasonable steps are being taken to address this gap. However, AEMO will continue to work closely with ElectraNet to monitor remediation activities, and to identify any options for acceleration or additional remediation.

Resecure risk in the western suburbs of Adelaide

AEMO has considered options to re-establish power system security associated with four contingency events in the western suburbs of Adelaide. While the studies indicate that the system will land in a satisfactory operating state following each contingency, it may be difficult to resecure the system for a second credible contingency or protected event without causing a reduction of local supply. This may result in load shedding at times of tight supply-demand balance.

[16] The reactive power required from a solution that addresses this gap will depend on the network location it is provided from.

[17] Two synchronous generating units are recommended for management of ramping events when South Australia is at credible risk of separation from the NEM or when South Australia is operating as an island.

[18] See https://www.electranet.com.au/projects/south-australian-transmission-network-voltage-control/.

AEMO has not declared an NSCAS gap for this risk, on the basis that the system can be secured, any impacts could be resolved by new supply elsewhere within the region, and the likelihood of unserved energy is low given the combination of supply-demand conditions required. There may still be market benefit associated with reducing the severity or likelihood of this event, and AEMO sees merit in further investigation by ElectraNet through the annual TAPR process.

Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in South Australia. Table 11 provides a comparison of binding hours and marginal values for the highest impact constraints observed[19]. All constraints with a marginal value exceeding $50,000 per year have previously been discussed with ElectraNet, which has confirmed the status, project, control scheme, or other mitigation strategy applicable for each. These options are being monitored through ElectraNet's annual TAPR process and may trigger action if market benefits exceed remediation costs.

Table 11 South Australian high-impact constraint summary

Constraint ID	Description	Marginal Value (↓↑ change)	Binding Hours	TNSP Comments
S>NIL_MHNW1_MHNW2	Avoid thermal overloads on Monash-North West Bend #2 132kV line for trip of Monash-North West Bend #1 132kV line	$12M (↑ $4M)	1,490	Project EC.15175 Increase Murraylink Transfer Capacity will alleviate this constraint [A].
S>NIL_HUWT_STBG3	Avoid thermal overload on Snowtown - Bungama line for loss of Hummocks - Waterloo line.	$5M (↑ $5M)	375	ElectraNet are monitoring to determine if proposed project EC.15571 10-band rating NCIPAP project is likely to alleviate this constraint [A].
S^NIL_PL_MAX	Voltage stability upper limit on generation at Port Lincoln.	$2M (↑ $2M)	44	Eyre Peninsula Link was completed in February 2023 and alleviates this constraint. AEMO has observed a notable reduction since that time.
S>NIL_NWRB2_NWRB1	Avoid thermal overload on North West Bend-Robertstown #1 132kV line on trip of North West Bend-Robertstown #2 132kV line	$1M (↑ $1M)	214	Murraylink Automated Run-Back Scheme monitors this line. Project EC.15175 Increase Murraylink Transfer Capacity will upgrade this control scheme.
SVML^NIL_MH-CAP_ON	Voltage stability upper transfer limit on Murraylink from South Australia to Victoria to manage voltage collapse at Monash (note: applies when capacitor banks at Monash are available and I/S for switching.)	$1M (↑ $1M)	447	Proposed project EC.15175 Increase Murraylink transfer capacity will alleviate this constraint [A].

Note: from annual NEM Constraint Report: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been further prioritised on data to July 2023.
A. See Table 7 page 69 of ElectraNet's TAPR, October 2023, athttps://www.electranet.com.au/wp-content/uploads/231115_2023-TAPR.pdf.

[19] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the NSCAS Description and Quantity Procedure: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en.

2.4 Tasmania

AEMO has not identified any NSCAS gaps in Tasmania over the five-year period. AEMO acknowledges that TasNetworks is procuring system strength and inertia services in response to requirements in those planning frameworks, and that these may support other power system security needs in the region. Future power system changes, including connection of new large loads, could impact voltage control and reactive margins in some locations, and AEMO will continue to monitor these risks.

Scope of assessment

AEMO has assessed NSCAS needs in Tasmania over the five-year outlook period. To study the most onerous voltage control scenarios, Basslink was modelled as exporting to Victoria during high demand conditions and importing to Tasmania during low demand conditions.

Table 12 provides an overview of the core scenarios studied for Tasmania. These are based on committed, anticipated, and actionable transmission projects; committed and anticipated generation; announced generator retirements; and forecast changes in demand[20]. Appendix A1 provides further detail on the specific input sources, modelling assumptions, and study methodologies used for the 2023 NSCAS assessment.

Table 12 Tasmanian NSCAS scenarios and outcomes

Case	Project assumptions	Year	NSCAS gap
High demand	Committed projects only	2028-29	No new gaps identified
	Committed and anticipated		No new gaps identified
Low demand (day)	Committed projects only	2028-29	No new gaps identified
	Committed and anticipated		No new gaps identified
Low demand (night)	Committed projects only	2028-29	No new gaps identified
	Committed and anticipated		No new gaps identified

Note: While core studies were based on 2022 ESOO demand projections, screening studies were conducted to confirm potential impacts of lower minimum demand forecast in Tasmania in the 2023 ESOO. No additional issues were identified.

Reactive margin

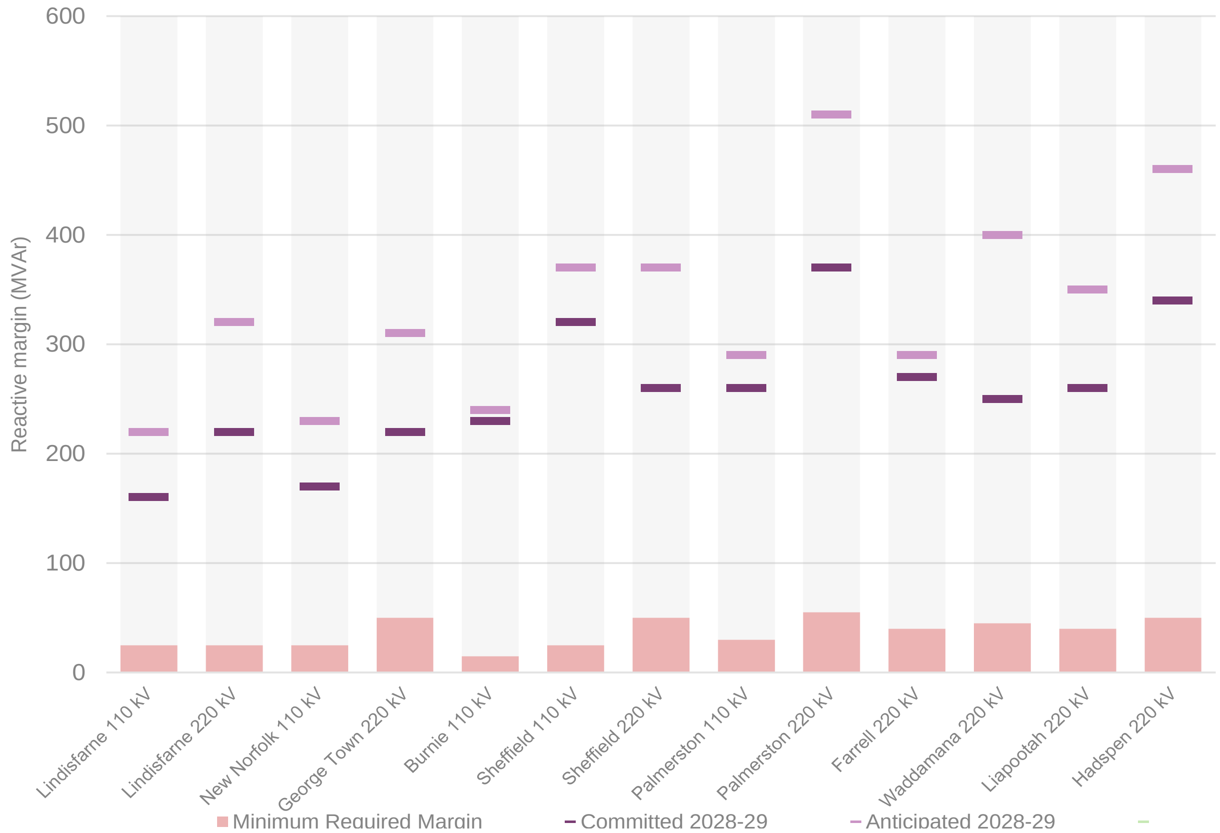
AEMO assessed whether the system normal and post-contingent reactive margins at critical buses Tasmania are expected to remain above the system standard [21] of 1% of the local maximum fault level[22] over the five-year outlook period. Figure 4 summarises the results of this analysis, which indicate that all reactive margins remain above the system standard.

[20] 2023-24 was not studied, because 2028-29 does not include new generation or transmission projects, and has similar demand.

[21] Required reactive margin is defined by NER S5.1.8 as "*not less than 1% of the maximum fault level (in MVA) at the connection point*". For the purposes of this assessment, the required reactive margin was calculated based on the 2023-24 maximum fault level.

[22] The required reactive margins were calculated using the system fault levels available from the TasNetworks 2022 Annual Planning Report system fault levels, at https://www.tasnetworks.com.au/Documents/Manual-documents/Planning-and-upgrades/APR/2022-Fault-levels-and-sequence-impedances. The calculated MVAr was rounded to the nearest 5.

Figure 4 Minimum observed reactive margin (MVAr) for critical buses in Tasmania



Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in Tasmania. Table 13 summarises the results of this analysis, which indicate that all outcomes remain within the system standard [23].

While the studies identified some deviations exceeding the most onerous standard of 2.5% nominal voltage, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the Australian Standard.

Table 13 Rapid voltage change results for reactive plant switching in Tasmania

Case	Project assumptions	Year	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant
High demand	Committed projects only	2028-29	2.2%	Starwood 110 kV	42 MVAr capacitor bank at George Town 110 kV
	Committed and anticipated		2.2%	Starwood 110 kV	42 MVAr capacitor bank at George Town 110 kV
Low demand day	Committed projects only	2028-29	3.4%	Risdon 110 kV	40 MVAr capacitor bank at Risdon 110 kV
	Committed and anticipated		1.4%	Risdon 110 kV	40 MVAr capacitor bank at Risdon 110 kV
Low demand night	Committed projects only	2028-29	1.7%	Risdon 110 kV	40 MVAr capacitor bank at Risdon 110 kV
	Committed and anticipated		1.5%	Risdon 110 kV	40 MVAr capacitor bank at Risdon 110 kV

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

Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Tasmania. Table 14 provides a comparison of binding hours and marginal values for the highest impact constraints observed[24]. All constraints with a marginal value exceeding $50,000 per year have previously been discussed with TasNetworks, and TasNetworks has confirmed the status, project, control scheme, or other mitigation strategy applicable for each. These options are being monitored through the TasNetworks annual TAPR process and may trigger action if market benefits exceed remediation costs.

Table 14 Tasmanian high-impact constraint summary

Constraint ID	Description	Marginal Value (↓↑ change)	Binding Hours	TNSP Comments
T::T_NIL_1	Prevent transient instability for fault and trip of a Farrell to Sheffield line.	$0.4M (↓ $0.1M)	280.8	Planned future augmentation of Sheffield-Palmerston 220 kV will assist with this constraint.
T^V_NIL_8	Prevent voltage collapse at Georgetown 220 kV for loss of a Sheffield to George Town 220 kV line, if Tamar Valley CCGT out of service, and considering GTRSPS.	$0.3M (↑ $0.3M)	9.0	This constraint was seen to be binding only when Tamar Valley CCGT was not in service.
T>T_NIL_BL_IMP_6EE	Avoid thermal overload on Sheffield to Georgetown No. 2 220 kV line for trip of the Sheffield to Georgetown No. 1 220 kV line, with no SPS.	$0.2M (↑ $0.2M)	6.3	This constraint was seen to be binding only when the Special Protection Scheme (SPS) was not in service.
T_MRWF_GCS	Musselroe wind farm Generator Control Scheme (GCS) constraint to maintain TAS FOS for a Tasmanian generator event.	$0.2M (↑ $0.2M)	113.8	This constraint was seen to be binding only when GCS was not arming enough load.
T::T_NIL_3	Prevent poorly damped TAS North - South oscillations following fault and trip of Palmerston to Sheffield 220 kV line.	$0.2M (↑ $0.2M)	120.8	Planned transmission augmentation works in Sheffield-Palmerston 220 kV corridor will assist with this constraint.

Note: From annual NEM Constraint Report: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been further prioritised on data to July 2023.

[24] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is in the NSCAS Description and Quantity Procedure, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en.

2.5 Victoria

AEMO has identified an RSAS gap for thermal overloading and voltage control following credible contingencies on the 220 kV network near Deer Park. This is associated with projected connection point demand growth, and AEMO Victorian Planning (AVP) is working closely with the local DNSP to review the associated demand projections, and to identify appropriate investment options and timing. The 2023 *Victorian Annual Planning Report* (VAPR) confirms these as new priority limitations, and has committed to pre-feasibility work on credible options to address the thermal limit, while considering the voltage control limits as part of the broader Metropolitan Melbourne Voltage Management RIT-T.

The NSCAS assessment has also confirmed overloading risks on transformers between the 500 kV and 220 kV network supplying Metropolitan Melbourne. These limits tighten following the announced retirement of Yallourn Power Station, and may require investment to maintain reliable supply to Melbourne during peak demand periods from early 2029. AVP has developed an operational solution, and will consider longer-term remediation options if required.

Scope of assessment

AEMO has assessed NSCAS needs in Victoria over a five-year outlook period. Minimum demand scenarios have not been reassessed, because newly committed and anticipated projects have improved expected voltage control outcomes since minimum demand studies were last conducted in December 2022.

Table 15 provides an overview of the core scenarios studied for Victoria. These are based on committed, anticipated, and actionable transmission projects; committed and anticipated generation; announced generator retirements; and forecast changes in maximum demand. Appendix A1 provides further detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2023 NSCAS assessment.

Table 15 Victorian NSCAS scenarios and outcomes

Case	Project assumptions	Year	NSCAS gaps
High demand	Committed projects only	2023-24	Thermal overloading RSAS gap for Deer Park
	Committed projects only	2028-29	Supply reliability RSAS gap for Melbourne
	Committed and anticipated	2028-29	Supply reliability RSAS gap for Melbourne

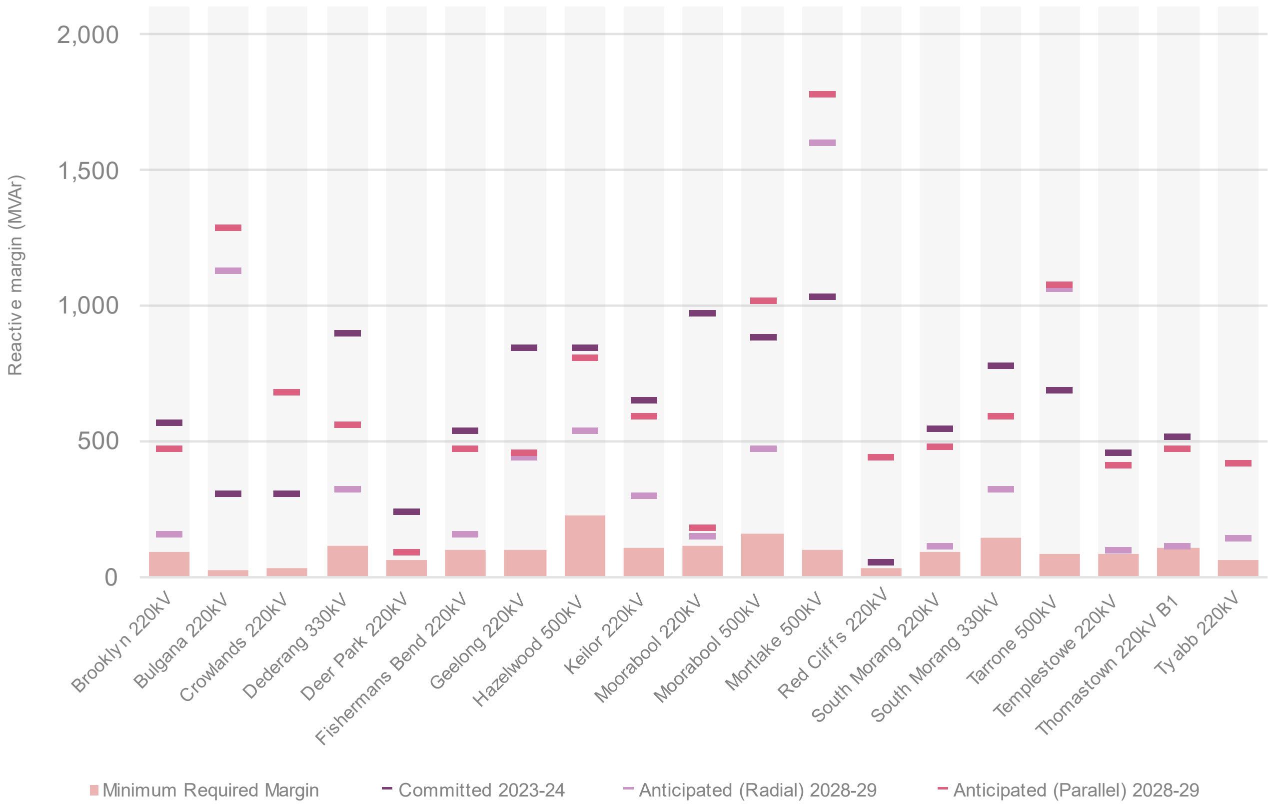
Note: While core studies were based on 2022 ESOO demand projections, AEMO has also conducted sensitivity studies to confirm any potential impacts of the updated 2023 ESOO demand forecasts in Victoria. Increases in forecast maximum demand could apply extra pressure to voltage management challenges by the end of the horizon, however this is sensitive to changes in anticipated projects, and no additional gaps were identified.

Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in Victoria are expected to remain above the system standard[25] of 1% of the local maximum fault level over the five-year outlook period. Figure 5 summarises the results and indicates that all reactive margins remain above the standard.

These results were based on operating the Latrobe Valley in radial mode[26], and reactive margins typically improved when assessed under parallel network configurations.

Figure 5 Minimum reactive margin (MVAr) observed for critical buses in Victoria



Rapid voltage changes

AEMO assessed the expected voltage change impacts of switching reactive plant in Victoria. Table 16 summarises the results of this analysis, which indicate that all outcomes remain within the system standard [27].

While the studies identified some deviations exceeding the most onerous standard of 2.5% nominal voltage, the expected switching frequency of these specific assets is low enough to be assessed against the wider voltage change criteria of between 3% and 5% under the Australian Standard.

[25] Required reactive margin is defined by NER S5.1.8 as "*not less than 1% of the maximum fault level (in MVA) at the connection point*". For the purposes of this assessment, the required reactive margin was calculated based on the 2023-24 maximum fault level provided by AVP.

[26] See AEMO, 2022 VAPR, Figure 37, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2022/2022-victorian-annual-planning-report.pdf.

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

Table 16 Rapid voltage change results for reactive plant switching in Victoria

Case	Project assumptions	Year	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant
Maximum demand	Committed projects only	2023-24	2.5%	Altona 220 kV	200 MVAr capacitor at Altona 220 kV
	Committed and anticipated (radial)	2028-29	2.8%	Templestowe 220 kV	200 MVAr capacitor at Templestowe 220 kV
	Committed and anticipated (parallel)	2028-29	2.6%	Templestowe 220 kV	200 MVAr capacitor at Templestowe 220 kV

Thermal limits and voltage control challenges near Deer Park 220 kV

AEMO has confirmed thermal overloading and voltage control risks associated with demand growth at Deer Park. This was previously identified in the 2022 VAPR as a 'developing limitation', however the latest maximum demand forecast for Deer Park[28] is projected to be above the 40°C firm ratings of the 220 kV lines that supply it from Keilor and Geelong.

The severity of post-contingent overloads will increase as demand continues to grow, and AEMO considers that this represents an immediate RSAS gap of 50 MW, rising to 100 MW by the end of 2024-25 and remaining steady until further demand growth is projected beyond 2028-29. The 2023 VAPR identifies this as a priority thermal limitation, and AVP have committed to pre-feasibility studies to assess all credible options for improving capacity in the western metro 220 kV corridor, including at Deer Park. AVP is engaged in joint planning with the local DNSP to further review connection point demand projections, and to identify appropriate investment options and timing.

AEMO also noted a 75 MVAr voltage control risk under some operating conditions in the final year of study. This may indicate the need for additional reactive support near Deer Park towards the end of the NSCAS horizon, and AVP have included this emerging need in their Metropolitan Melbourne Voltage Management RIT-T[29].

Transformation limits between the 500 kV and 220 kV metropolitan Melbourne network

The NSCAS studies identified an emerging risk for reliability of supply caused by transformer loading limits at key points between the 500 kV and 220 kV network supplying Metropolitan Melbourne. These limits tighten following the announced retirement of Yallourn Power Station and may require remediation to maintain supply reliability during peak demand from early 2029. These reliability gaps exist, even for scenarios that include both committed and anticipated projects.

AEMO considers this is a candidate for NSCAS (rather than a supply shortfall) because there is a limiting network element, localised unserved energy outcomes, and because additional supply within the region is only effective in very specific locations. Additional generation on the 500 kV backbone may even exacerbate this limitation.

Under a radial configuration of the Latrobe Valley network[30], the 500/220 kV transformers at Rowville and South Morang are forecast to experience both pre- and post-contingent thermal overloads for maximum demand conditions from early 2029. Additional post-contingent thermal overloads are observed on the 220 kV corridors that transport energy from the transformation points into metropolitan Melbourne itself.

[28] See combined Victorian 2023-2027 Distribution Annual Planning Report data, published at https://dapr.ausnetservices.com.au/.

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

[30] See AEMO, 2023 VAPR, Figure 23, athttps://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2023/2023-victorian-annual-planning-report.pdf?la=en.

The 2023 VAPR has identified this as a priority limitation and has developed a switching arrangement that would reconfigure the Latrobe Valley network into parallel mode and attempt to reduce loading on the 500 kV network by redirecting flows onto the 220 kV corridor. AVP intends to shortly commence a scoping project to confirm the practical details necessary to facilitate this switching arrangement from 2028.

While the proposed network reconfiguration is expected to be sufficient to manage near-term thermal overloads following closure of Yallourn Power Station, continued demand growth beyond 2028 may require additional long-term remediation. AEMO with continue to work with AVP to monitor the network needs as they approach.

Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Victoria. Table 17 provides a comparison of binding hours and marginal values for the top impact constraints in Victoria[31]. All constraints with a marginal value exceeding $50,000 per year have previously been considered by AVP. In each case, a risk status, project, control scheme, or other mitigation strategy has been identified. These options are being monitored through the annual VAPR process and may trigger action if market benefits exceed remediation costs.

Table 17 Victorian high-impact constraint summary

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
V^^N_NIL_1	Avoid voltage collapse around Murray for loss of all APD potlines	$8M (↑ $7M)	390	South-west Victoria activities are expected to alleviate this constraint.
V^^V_NIL_KGTS V^^V_NIL_KGTS_2	Avoid voltage collapse for loss of either Crowlands-Bulgana-Horsham lines or the Horsham-Murra Warra-Kiamal 220 kV lines	$6M (↑ $3M)	843	Changes to Murraylink runback scheme have alleviated this constraint in more recent months of the dataset.
V>>V_NIL_18	Avoid overloading Ararat-Waubra 220 kV line for trip of Kerang-Bendigo 220 kV line.	$6M (↑ $4M)	466	Victorian Government RDP Minor Augmentations[A] will reduce this impact.
V>>V_NIL_7	Avoid overloading Waubra-Ballarat 220 kV line for trip of Red Cliffs-Wemen-Kerang 220 kV line.	$2M (↑ $1M)	117	Victorian Government RDP Minor Augmentations[A] will reduce this impact.
V^^V_MLNK_KGTS	Avoid voltage collapse for loss of either Crowlands-Bulgana-Horsham lines or the Horsham-Murra Warra-Kiamal 220 kV line.	$2M (↓ $1M)	128	Under investigation as part of the 2023 VAPR process. Historically this has been largely driven by outages.

Note: from annual NEM Constraint Report: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams. Constraints have been further prioritised on data to July 2023.
A. See http://www.gazette.vic.gov.au/gazette/Gazettes2022/GG2022S547.pdf.

[31] Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is in the NSCAS Description and Quantity Procedure, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en.

3 Preparing for high instantaneous renewable penetration

From 2025, there are forecast to be times when the NEM has enough renewable energy resources to meet 100% of its instantaneous demand. These periods will initially emerge at times of low demand, although continued investment will see them cover an increasing range of system conditions. This will create new needs for system security services, and the most efficient outcomes will depend on investments that can meet multiple needs at once.

AEMO has extended its previous 100% renewable studies to include high demand periods

In 2023, AEMO has studied system strength, inertia, and voltage control of the mainland NEM during periods where high demand is being met entirely by renewable sources. Renewable resources include both IBR such as wind farms, and synchronous generators such as hydroelectric generators. This builds on work presented in the 2022 NSCAS report, that explored challenges during low demand periods. The latest analysis confirms that:

- The most onerous requirements are likely to be those for system strength, which may require provision of system strength equivalent to more than 45 125 megavolt amperes (MVA) synchronous condensers. Of this, approximately 50% is needed to meet minimum fault level requirements and must be met by devices that provide fault current – such as new synchronous condensers, service contracts with existing hydro or thermal units, or by the retrofit of those existing units themselves. The remaining 50% is necessary to accommodate future IBR and could be met by a variety of new technologies, including grid forming inverters.
- Inertia needs can be met alongside system strength, provided that the benefits of inertia services are considered in conjunction with the procurement of system strength services.
- Voltage control needs are largely met by the additional reactive capabilities provided by IBR investment, particularly when IBR is installed in sufficient volumes to meet maximum demand conditions.

These results are indicative and consider only a subset of system security quantities. They also assume an underlying power system with optimised network and generation build patterns consistent with the 2022 *Integrated System Plan* (ISP) *Step Change* scenario. More information about the full range of measures that may be required can be found in AEMO's *Engineering Roadmap to 100% Renewables*[32].

This analysis is based on a representative high-demand power system snapshot for 2029-30 under the *Step Change* scenario, which was then adjusted to operate with 100% renewable generation. Studies explored the need for system strength, inertia, and voltage control services.

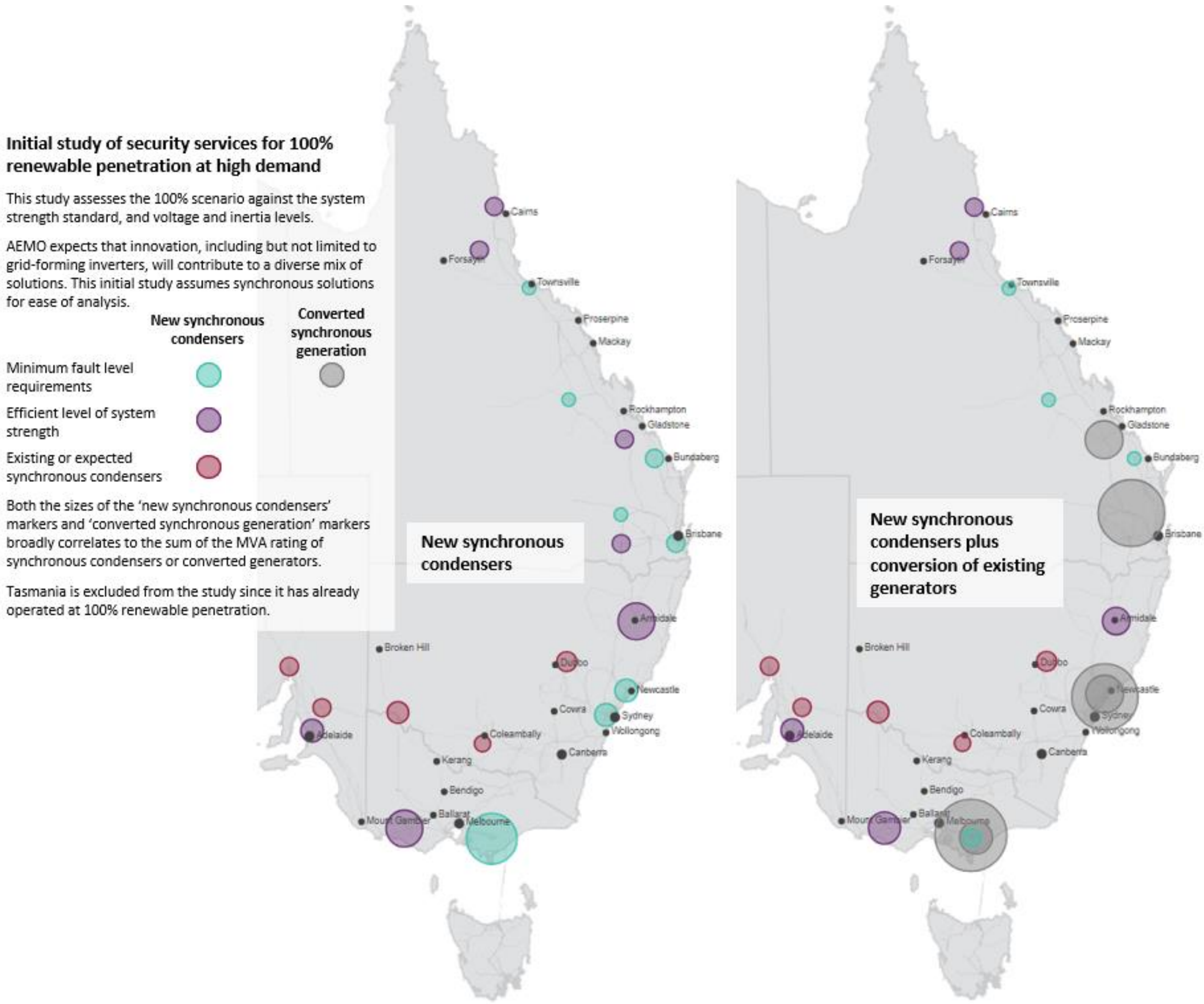
[32] At https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

In assessing the associated security requirements, AEMO considered the minimum and efficient levels of system strength set out in the 2022 *System Strength Report*[33], the secure operating levels of inertia described in the 2022 *Inertia Report*[33, 34] , existing network asset ratings, and a pre- and post-contingent voltage range of 0.9-1.1 pu.

System strength assessment

AEMO has assessed the level of investment needed to meet the minimum fault level requirements, and efficient level requirements defined in the 2022 *System Strength Report*. An overview of these results is shown in Figure 6.

Figure 6 System strength needs for 100% renewable penetration at times of high demand



These underlying results indicate that:

- An equivalent of 45 125 MVA synchronous condensers is required to meet system strength needs.

[33] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[34] While inertia requirements have been reviewed for some regions in the 2023 *Inertia Report*, the 2022 inertia requirements were applied for these studies. The updated inertia requirements do not affect outcomes presented in this section.

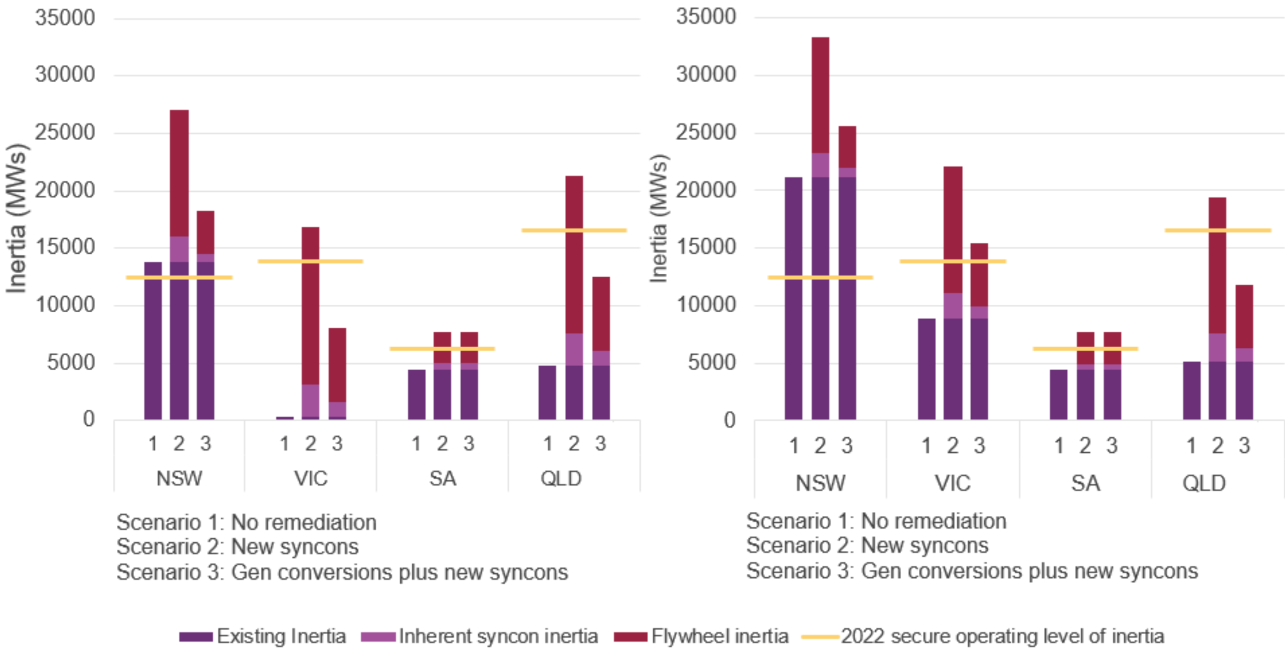
- Of these, 22 are required to meet the minimum fault level requirements and are likely to be met by new synchronous condensers, contracts with existing units to provide system strength services, or by the retrofit of existing thermal units themselves. The remainder are necessary to accommodate the stable operation of future IBR and could be met by a variety of new technologies, including grid forming inverters.
- The total requirement is higher than reported in the 2022 studies, because additional system strength is needed to accommodate the higher output and number of inverters online at times of higher demand.

Inertia assessment

AEMO assessed available inertia levels across several remediation scenarios to identify shortfalls against the current secure operating level for each region. For cases where system strength remediation is applied, AEMO assumed that synchronous condensers provide an inherent 187.5 megawatt seconds (MWs) of inertia, that new flywheels increase this to a total of 1,100 MWs of inertia, and that retrofitted synchronous generators have their turbines removed and do not provide inertia.

Figure 7 shows the projected levels of inertia available in each region for all conditions studied.

Figure 7 Projected inertia with (left) and without (right) hydro units as synchronous condensers



These results are broadly consistent with those observed in the 2022 studies, and indicate:

- All regions except New South Wales exhibit inertia shortfalls when no remediation is applied.
- Inertia requirements can be met in all regions when system strength needs are met by synchronous condensers, provided that at least some of these are installed with flywheels. The proportion that would require flywheels depends on the size installed at each, and the reliable quantity of fast frequency response available in the frequency control ancillary services (FCAS) markets.

- It is also possible to meet inertia requirements when some system strength needs are met through the retrofit of existing synchronous generators; however, the results become region-specific and would require the use of larger flywheels (or alternative inertia services) to meet requirements in Queensland.
- In all cases, pumped hydro units with the capability to operate in synchronous condenser mode when not otherwise dispatched would further improve inertia outcomes (or reduce flywheel investment needs).

Voltage control study results

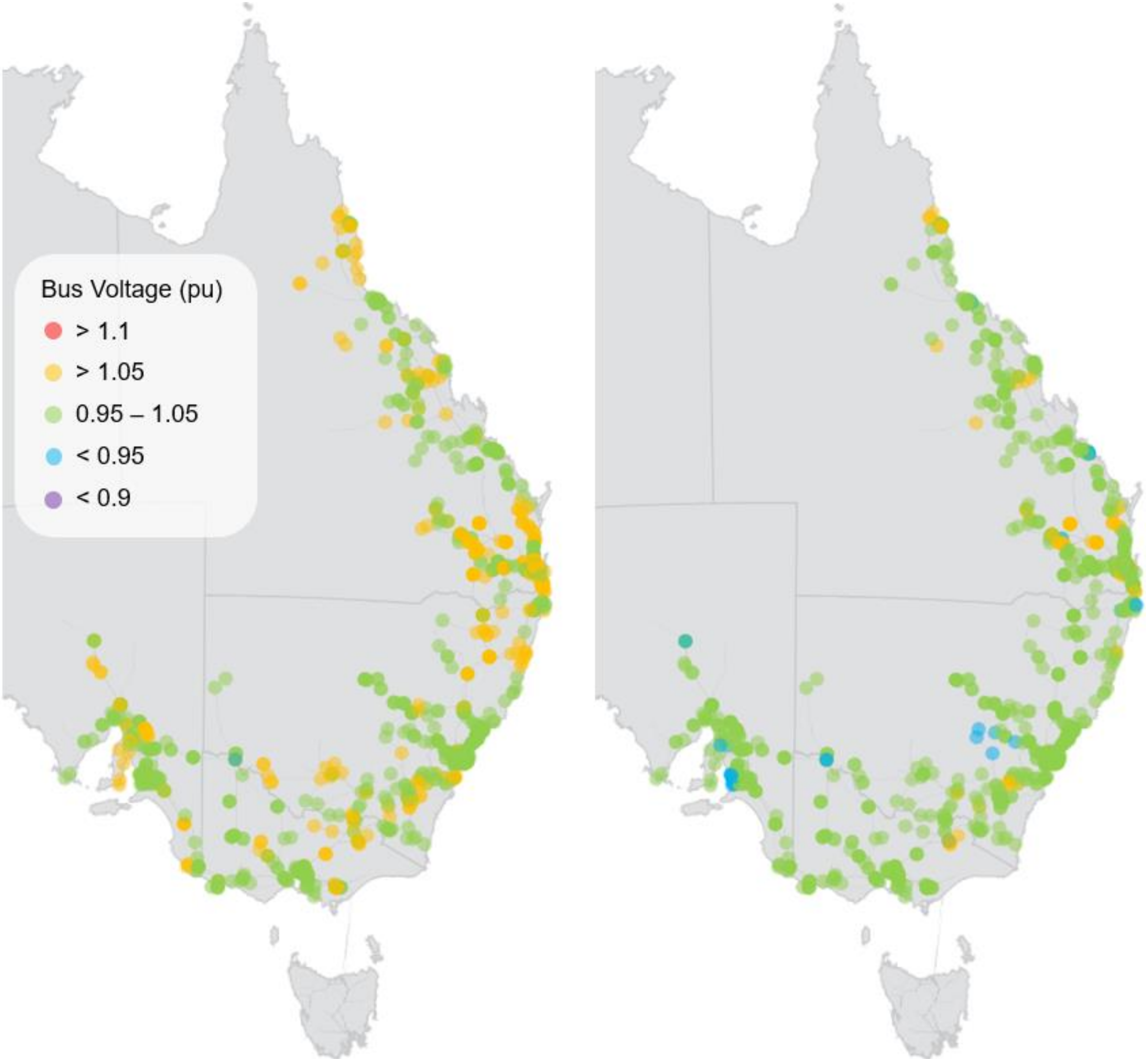
AEMO assessed voltage control across the NEM when operating at 100% renewable penetration at near-peak demand. For this study, the reactive capability of new generators was assumed to be 39.5% of the unit's rated active power output, and voltage thresholds were assumed to be 0.9 and 1.1 pu across the NEM.

Figure 8 shows the maximum and minimum post-contingency voltage levels observed at the transmission buses[35]. AEMO has not identified any pre- and post-contingent bus voltage violations in the network for the high demand scenario, with or without further investment in security services. Voltage control needs have been largely met by the additional reactive capabilities of IBR investment.

This differs from the 100% renewable results presented for minimum demand conditions in the 2022 report. Those results showed that some investment would be required to resolve voltage control challenges. However, the maximum demand studies have modelled higher levels of installed IBR as necessary to meet the higher energy requirements of this scenario. This additional IBR is providing an associated increase in reactive capability.

[35] AEMO did not study Tasmania explicitly, because that region is already able to operate at 100% renewable penetration.

Figure 8 Maximum (left) and minimum (right) post-contingent voltages without mitigation



Ramping risks in the NEM

The magnitude of potential ramping events across the NEM continues to grow as new weather-dependent resources are connected on both sides of the supply-demand balance. These weather dependent events have been highlighted in previous AEMO work, notably the Renewable Integration Study[36] and Engineering Roadmap[37]. In 2023, AEMO has performed an initial analysis of these challenges as part of the NSCAS voltage control screening studies.

While the studies have not identified any NSCAS gaps, they do highlight the growing need for dynamic reactive support as voltages become increasingly sensitive to changes in power flow not previously experienced in the NEM, and the importance of continuing to review and adapt contingency management practices with consideration for the size of ramping events.

[36] See https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris.

[37] See https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

In keeping with the NSCAS framework, AEMO has focused on practical (rather than extreme) ramping situations that are loosely based on historical events. These ramping scenarios were then scaled up to reflect the expected levels of IBR and CER in AEMO's 2022 ISP *Step Change* scenario, over the five-year NSCAS horizon.

In each case, the analysis focused on interconnector management and local network security impacts. AEMO did not assess supply adequacy, which was considered outside the scope of the NSCAS framework.

The studies considered three diverse scenarios, as described in Table 18. This analysis found that:

- The network was able to operate securely before, during, and after the coincident weather ramping and contingency events. No voltage or thermal violations were identified under pre- or post-contingent conditions.
- Projected ramping impacts were in the same range as most large network contingency events, and existing power system mechanisms and operating practices were sufficient to manage the conditions. This highlights the importance of continuing to review and adapt the approach to contingency management in the NEM, including through ongoing consideration of any sympathetic CER tripping.
- The most challenging near-term ramping impacts are likely to be a growing need for dynamic reactive support, driven by increased sensitivity of network voltages to changes in power flows. This tends to occur on interconnectors and is exacerbated as synchronous plant withdraw, and available fault levels reduce towards their minimums.

While steady-state planning studies can find secure load flow solutions to ramping events, this may not capture the operational challenges associated with large ramps and volatile flow patterns. AEMO has already detected real-time instances of both high and low voltage alarms simultaneously, requiring complex and rapid response, and ongoing monitoring. The voltage control gap identified in New South Wales (see Section 2.1) is a practical example of this type of emerging event. This may highlight the need for more automated (dynamic) reactive plant, and the importance of leveraging the controllable reactive capabilities of new IBR connections.

Table 18 Summary of ramping cases studied

Cause of ramping	Based on timestamp	Size of ramp	Impact on network	Observations
Reduction of distributed PV generation in western Sydney	05/12/2022 1430	570 MW increase in operational demand	Ramping flow from Redcliffs (Victoria) to Buronga (New South Wales)	No thermal or voltage limit violations identified during contingency analysis.
Reduction in rooftop PV in Brisbane	02/05/2023 1430	500 MW increase in operational demand	Ramping flow on QNI from New South Wales to Queensland	No limit violations identified, however managing changes in load power factor relied on dynamic reactive plant in Southern Queensland.
Reduction in wind generation in South Australia	09/08/2023 0830	500 MW drop off in wind generation	Ramping flow on Heywood Interconnector from Victoria to South Australia	No thermal or voltage limit violations identified during contingency analysis.

4 Next steps

Based on the 2023 NSCAS studies, AEMO has confirmed that the previous RSAS gaps in New South Wales and Queensland are closed, and has identified new RSAS gaps in Victoria and South Australia. Table 19 summarises these findings, and AEMO will work closely with the TNSPs to develop or monitor remediation plans for each gap.

AEMO also welcomes any comments, questions, or suggestions on this report via planning@aemo.com.au.

Table 19 Summary of new and existing NSCAS gaps

Region	NSCAS gap
New South Wales 	**The existing RSAS gap at Coleambally has been closed.** Transgrid has temporary operating measures in place and is progressing long-term remediation through a RIT-T. **AEMO notes a voltage control need affecting network near Canberra, Yass, and Lower Tumut** when no nearby hydro generating units are online and Victoria is exporting at least 700 MW to New South Wales. Temporary operating measures are in place, and the underlying need is expected to be resolved by committed projects ahead of May 2024.
Queensland 	**The existing RSAS gap in Southern Queensland has been closed.** Powerlink has a network support agreement in place until January 2024 and has concluded a RIT-T for long-term remediation to be delivered in late 2024. The gap will reopen for the intervening period, and Powerlink are progressing further interim arrangements.
South Australia 	**AEMO is declaring an RSAS gap for voltage control in South Australia.** ElectraNet is progressing a RIT-T which is expected to close this voltage control gap, and subsequently to allow operation with fewer synchronous generating units online once paired with PEC and an adequate demonstration of grid reference in South Australia. AEMO will continue to work closely with ElectraNet on additional options or acceleration.
Tasmania 	**AEMO has not identified any NSCAS gaps in Tasmania over the five-year period.** AEMO acknowledges that TasNetworks is procuring system strength and inertia services in response to requirements in those planning frameworks, and that these may support other power system security needs in the region.
Victoria 	**AEMO is declaring an NSCAS gap for thermal loading and voltage stability near Deer Park.** This relates to projected demand growth at the Deer Park Terminal Station, and AVP has committed to pre-feasibility work on the thermal limitations, and is considering voltage needs through its broader Metropolitan Melbourne Voltage Management RIT-T. **AEMO also identified an emerging risk for reliability of supply to Melbourne from early 2029.** This may require investment to maintain reliable supply during peak demand periods. AVP has developed an operational solution and will consider long-term remediation if required. More details are available in the 2023 VAPR.

A1. Methodology and inputs

AEMO has assessed NSCAS needs in each region over a five-year outlook period under maximum and minimum demand conditions. The underlying analysis considers a range of power system requirements, and this appendix provides an overview of the methodology and input data sources used to conduct these studies.

In some cases, an alternative scenario or bespoke set of study conditions was needed to explore specific regional issues or observed operational challenges. These exceptions are described in more detail as they occur through the regional sections of the main report.

All assessments have been conducted in accordance with the latest NSCAS procedures[38], and are based on the latest available data at the point where studies were initiated. In most cases, this data cut-off was 1 July 2023.

A1.1 Study methods and parameters

Contingency analysis

Contingency analysis simulates the state of the power system following a credible contingency event. This type of study is typically used to identify network elements where thermal ratings or voltage limits are exceeded. In the NSCAS context, contingency events are applied independently to an initially secure power system, and the results are monitored to confirm that no single credible event would cause limit violations.

AEMO conducted this analysis using PSS®E load flow studies with the following settings:

- Loads were modelled as constant power.
- Pre-contingency cases were solved using the Newton-Raphson method, with transformer taps allowed to move and shunts allowed to switch.
- Post-contingency transformer taps and shunts were locked.

Reactive margin

Reactive margins indicate the additional reactive loading that could be applied at a network location before it would result in voltage collapse. Low levels of reactive margin indicate that the system is at greater risk of such collapse, and these could exist even when absolute voltages appear normal. NER S5.1.8 requires that reactive margins remain above 1% of the maximum fault level at each connection point, and AEMO has applied this standard when assessing NSCAS needs in each region.

Reactive margins can be derived from a QV curve, which shows the amount of reactive power (Q) required for a specified voltage level (V). These curves exhibit a knee-point, below which the system is deemed to be unstable. The position of this knee-point indicates whether there is excess reactive margin, or a reactive margin shortfall.

AEMO used PSS®E for this assessment, coupled with an in-house python tool that automates the study process. In particular, the tool creates a QV curve for each specified bus, based on a set of given contingencies. It does

[38] AEMO. NSCAS description and quantity procedure, version 2.2. December 2021, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

this by applying a fictitious synchronous condenser and varying its target voltage to observe the required reactive power output and to achieve each voltage setpoint.

Rapid voltage change

When reactive power devices are switched in or out of service on the network, nearby voltage levels are impacted. The size of these impacts can change over time as network loading, connections, and power flow patterns change. To avoid instability and provide operators with granular control of voltage, it is important that capacitor or reactor bank operation does not result in excessive voltage swings.

NER S5.1a.5 provides acceptable voltage change criteria, linked to the number of switching events that occur in each period. AEMO assumed the most onerous standard of 2.5% when screening voltage change outcomes, however a higher standard of 5% can also be applied for infrequent events.

AEMO assessed these values by running PSS®E's AC Contingency Calculation (ACCC) analysis on the relevant case with capacitor and reactor banks set as contingency events. For every reactive element contingency, the corresponding voltage change on all network buses can be observed and compared against the standard.

Resecure risk

While contingency analysis confirms whether the power system is robust to a single contingency, it does not consider what subsequent options are available to prepare the system for a further credible contingency or protected event. AEMO takes all reasonable actions to achieve this outcome during system operations. The 2023 NSCAS assessment has considered the risk of not re-establishing a secure operating state within this timeframe for several critical events, as identified collaboratively with the system operators and the network businesses.

These studies are typically quite manual, and tailored to very specific system conditions that maximise stress on the network or limit operational responses. Standard contingency analysis may be used, but more often a specific contingency event is selected, and AEMO then considers how operators would prepare the system to withstand the 'next worst' contingency event.

In cases where either no action, redispatch, or network reconfiguration are available options, the NSCAS studies consider these events to be resecurable. In cases where load shedding would be necessary to resecure the power system, the NSCAS studies flag these events for further consideration by the relevant TNSP. Only in cases where no operational solutions are available would the NSCAS studies consider this a potential NSCAS gap.

A1.2 Key input assumptions and sources

Generator and network project sources

The casefiles developed for the 2023 NSCAS assessments considered:

- All existing, committed, and anticipated scheduled and semi-scheduled generators and energy storage projects from the May 2023 NEM Generation Information page[39]. An updated NEM Generation Information page was published, and this was reviewed to ensure any impact to gaps were assessed.

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

- All announced generator withdrawals from the July 2023 NEM Generation Information page.
- If appropriate, projected renewable energy zone (REZ) development and generator withdrawals from the 2022 ISP *Step Change* scenario[40].
- Committed, anticipated, and actionable transmission projects from the July 2023 NEM Transmission Augmentation Page[41].
- Voltage planning assumptions consistent with those developed in 2021 and published in Appendix A2 of the 2022 NSCAS report[42].
- Forecast maximum demand projections for each region from the 10% probability of exceedance (POE) and forecast minimum demand projects from the 90% POE current trajectory in the 2022 *Electricity Statement of Opportunities* (ESOO) for the NEM[43, 44].

Case development

Cases were developed by:

- Extracting representative maximum demand and minimum demand casefiles for each region.
- Confirming all existing, committed, and advanced generation and storage projects, static VAR compensators (SVCs), and synchronous condensers were modelled correctly according to their Generator Performance Standards (GPS), particularly their reactive capability. For future casefiles, new generating and storage projects were added according to their expected full commercial use date published on the NEM Generation Information page.
- Dispatching renewable generation according to conservative assumptions for expected availability during maximum and minimum demand periods[45].
- Adding future transmission augmentation projects using modelling data received from the relevant TNSP.
- Scaling real power demand based on the 10% and 90% POE forecasts from the 2022 ESOO. Demand was scaled using a constant PQ ratio for maximum demand scenarios. Reactive power was not scaled for minimum demand scenarios.
- Interconnector flow and synchronous generation dispatch was then adjusted to meet demand while keeping the system within network limits.
- This process was repeated as necessary for each region and year studied.

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

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

[42] AEMO. 2022 NSCAS Report. December 2022, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/2022-nscas-report.pdf?la=en.

[43] 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.

[44] While core studies were based on 2022 ESOO demand projections, AEMO has also conducted sensitivity studies to confirm any potential impacts of the updated 2023 ESOO demand forecasts

[45] AEMO reviewed 2022 ESOO market modelling results and consulted with TNSPs to agree on conservative assumptions for renewable generation dispatch.