Update to 2021 System Security Reports

May 2022

A report for the National Electricity Market

Important notice

Purpose

The purpose of this publication is to provide an update to the system strength and inertia assessments conducted in the December 2021 System Security Reports for the National Electricity Market, in accordance with clauses 5.20.7 and 5.20.5 of the National Electricity Rules. This publication is generally based on information available to AEMO as at April 2022 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	17 December 2021	Nil.
2.0	11 May 2022	Updated results for system strength and inertia assessments for the National Electricity Market (excluding Tasmania), to incorporate: • Identification of the *Step Change* scenario as the most likely of the development scenarios for AEMO's 2022 *Integrated System Plan*. • Recent announcement by Origin Energy for the potential early retirement of Eraring Power station in August 2025.

Executive summary

AEMO has updated the National Electricity Market (NEM) system strength and inertia assessments in the original 2021 System Security Reports[1]. This update accounts for two material changes:

- Completion of updates to reflect the identification of the *Step Change* scenario as the most likely[2] of the development scenarios for AEMO's 2022 *Integrated System Plan* (the December 2021 report outcomes were based on the *Progressive Change* scenario).
- Recent announcement by Origin Energy[3] for the potential early retirement of Eraring Power Station in August 2025.

Continuing material power system and market changes during the energy transition are expected to extend the need for new system security services in the NEM

Many system security services in the NEM have traditionally been provided by large synchronous generation resources, and both the power systems and the market itself in the NEM were designed on this basis.

In this report, AEMO has further analysed the requirements for maintaining system strength and inertia as the system transitions to cater for ongoing material changes in the NEM. This analysis uses AEMO's *Step Change* scenario, which incorporates earlier retirements of synchronous generators in the NEM, as well as increases in utility-scale variable renewable energy (VRE) uptake and the recently announced potential for earlier retirement of Eraring Power Station.

AEMO's analysis shows the need for additional sources of system strength and inertia over the coming five-year period. The current framework requires that AEMO declare these requirements as a 'shortfall' to enable the relevant Transmission Network Service Provider (TNSP) to initiate steps to procure these services.

In particular:

- System strength projections for New South Wales and Victoria are lower than for the original 2021 *System Security Reports* due to the material changes, resulting in declaration of shortfalls. In addition, the existing system strength shortfall in Queensland is expected to be exacerbated.
- Inertia projections continue to decline for Queensland, New South Wales and Victoria. Shortfalls are not to be declared for New South Wales or Victoria under the current NEM inertia investment framework as those regions are not considered sufficiently likely to island from the NEM[4]. However, the inertia in each region is projected to fall below secure operating levels. AEMO will continue to assess potential future shortfalls after considering available inertia from adjacent regions. In Queensland, the previous inertia shortfall is cancelled due to improved outlook for available fast frequency control ancillary services (FCAS), but a potential future shortfall remains a possibility as the market changes.

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

[2] AEMO. *Draft 2022 Integrated System Plan*, December 2021. Section 2.3. Available at https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf?la=en.

[3] Origin Energy. 'Origin proposes to accelerate exit from coal-fired generation', February 2022. Available at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

[4] That is, electrically separate from adjacent regions such that there are no remaining synchronous high-voltage connections between the regions.

AEMO and networks will work together to ensure system strength and inertia needs are met

AEMO has declared revised system strength and inertia shortfalls in line with these outcomes (listed in Table 1) and will work closely with TNSPs and jurisdictional planning bodies on addressing these shortfalls. Where shortfalls overlap with the introduction of the new system strength rules provisions beyond December 2025, AEMO expects that planning bodies will address the shortfalls as part of their overall delivery against the new system strength standard.

AEMO expects to publish a Network Support and Control Ancillary Services (NSCAS) assessment later in 2022 to consider any other system security impacts of the recent announcement by Origin Energy.

Table 1 System strength and inertia outcomes in this report, 2022 to 2026, under *Step Change* scenario and other relevant updates

	System strength	Inertia
	The ability of the power system to maintain voltage waveform at any given location in the power system, both during steady state operation and following a disturbance.	A fundamental property of power systems such that the power system can resist large changes in frequency arising from an imbalance in power supply and demand caused by a contingency event.
New South Wales[B]	Shortfall ranging from 1,190 to 1,092 mega volt amperes (MVA) at Newcastle, and from 1,026 to 944 MVA at Sydney West, from mid-2025. AEMO will request services be available from 1 July 2025.	No shortfall declared with New South Wales unlikely to island, but strong decline in projected inertia observed.
Queensland[B]	Shortfall at Gin Gin for the full period, ranging from 33 to 90 MVA. AEMO will request services be available from 31 March 2023.	No shortfall declared, and previous shortfall rescinded, but possible future shortfall of 8,384 MWs from July 2026 in Queensland, subject to market assessments.
South Australia	No shortfall, with four new synchronous condensers now delivered by ElectraNet.	Shortfalls remain consistent with the declarations in the original 2021 *System Security Reports*.
Tasmania[A]	Shortfalls remain consistent with the declarations in the original 2021 *System Security Reports*.	Shortfalls remain consistent with the declarations in the original 2021 *System Security Reports*.
Victoria[B, C]	Shortfall of 203 MVA at Hazelwood from mid-2026. Shortfall of 31 MVA at Moorabool from mid-2026. Shortfall of 279 MVA at Thomastown from mid-2026. AEMO will request services be available from 1 July 2026.	No shortfall declared with Victoria unlikely to island, but strong decline in projected inertia observed.

Legend:	No shortfall	Possible future shortfall	Shortfall

A. The Tasmania region has not been included in this update, because the shortfall projections and outcomes provided in the 2021 *System Security Reports* already include reaching the current floor of minimum synchronous machines online in that region.
B. The system strength shortfalls declared in New South Wales, Queensland and Victoria fall either partially or completely within the post-2025 period. Beyond December 2025, the new 'Efficient management of system strength on the power system' rule change will be fully in effect, with transitional shortfall arrangements in place until that time. AEMO expects that in practice the relevant jurisdictional planning bodies will incorporate treatment of the post-2025 components of these shortfalls into their overall strategy for delivery of system strength services to meet the new system strength standard under the new rules framework.
C. Both the *2020 System Strength and Inertia Report* and the *2021 System Security Reports* noted that system strength outcomes in Victoria are heavily influenced by the reduction in the number of coal-fired machines online, and foreshadowed potential future system strength shortfalls at nodes in the metropolitan Melbourne area following the withdrawal of plant. Due to the greater decline in synchronous generation online in the *Step Change* scenario, these projected system strength shortfalls are brought forward to 2026-27 in this report. In March 2021, Energy Australia announced that Yallourn Power Station will retire in mid-2028, providing 7-years' notice in an agreement with the Victorian Government to ensure a smooth transition. The Victorian Government is also currently progressing a number of system strength projects under the Renewable Energy Zone Development Plan (Stage 1). The Victorian Government and AEMO, in its role as the jurisdictional planning body in Victoria, will continue to analyse the degree to which these arrangements will impact the declared shortfall.

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Figures

1 Introduction

This report provides an update to the 2021 *System Security Reports* that AEMO first published in December 2021[5], in respect of system strength and inertia only. AEMO plans to review the network support and control ancillary services (NSCAS) needs and issue any necessary updates later in 2022.

This update was initiated due to recent material changes impacting the power system, which AEMO considered likely to affect either the requirements or the declared shortfalls for system strength and inertia in the original 2021 *System Security Reports*.

This introduction outlines:

- Material changes since December 2021.
- The scope of this update.
- The relationship between AEMO's planning documents.

1.1 Material changes since December 2021

Step Change scenario

The original 2021 *System Security Reports* used the *Progressive Change* scenario as the basis of the system strength and inertia assessments, being the analysis available at the time of the assessment. However, based on stakeholder input during its development, the Draft 2022 *Integrated System Plan* (ISP) resolved that the *Step Change* scenario was the most likely[6] scenario. The key differences between the *Progressive Change* scenario and the *Step Change* scenario are:

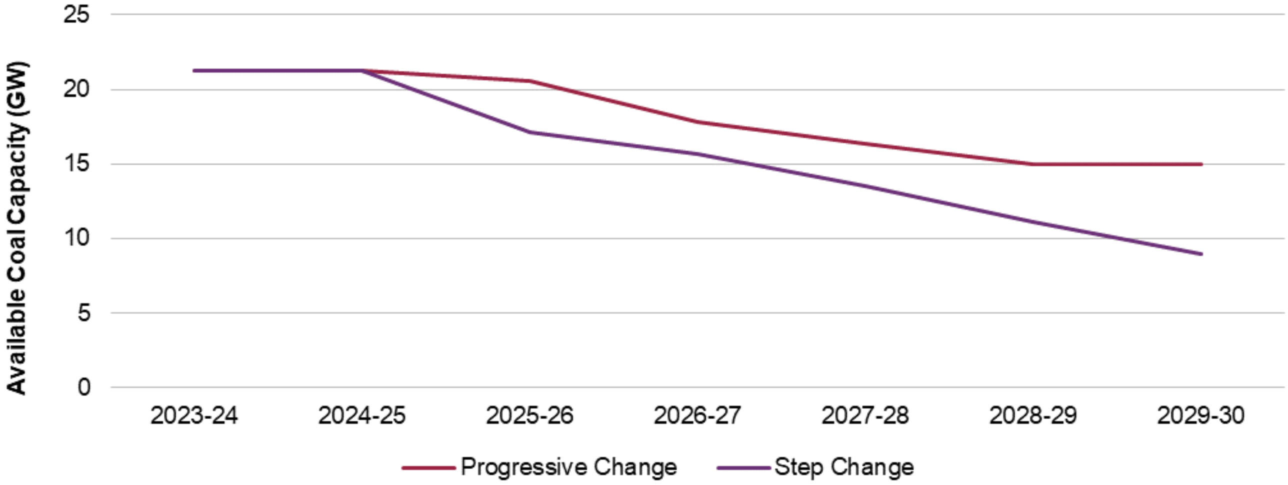
- **Synchronous generation behaviour and variable renewable energy (VRE) uptake projection**. The *Step Change* scenario has six additional coal units retiring and over 4 gigawatts (GW) of additional VRE capacity by 2026-27 compared to the *Progressive Change* scenario (see Figure 1). These differences have material implications for system strength and inertia assessments, as VRE resources are not typically direct substitutes for the system strength and inertia services provided by synchronous generating machines.
- **Minimum demand forecasts**. The minimum demand forecasts are higher for the *Step Change* scenario compared to the *Progressive Change* scenario, due to more electrification load in the *Step Change* scenario.

There is no difference in transmission network augmentation assumptions between the *Step Change* scenario and the *Progressive Change* scenario for the five-year outlook period originally considered for the 2021 *System Security Reports*.

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

[6] AEMO. *Draft 2022 Integrated System Plan*, December 2021. Section 2.3. Available at https://aemo.com.au/-/media/files/major-publications/isp/2022/draft-2022-integrated-system-plan.pdf?la=en.

Figure 1 Projected retirement of coal across the National Electricity Market: *Step Change* versus *Progressive Change*, 2023-24 to 2029-30



Potential early retirement of Eraring Power Station

Origin Energy[7] recently announced the potential early retirement of Eraring Power Station in August 2025. This timing is very closely aligned to that assumed for coal-fired generation in NSW in the Draft 2022 ISP *Step Change* scenario, and this update matches the potential early retirement. The previous expected closure year of 2032 was reflected in the ISP *Progressive Change* scenario.

Smoothing of results

The *Progressive Change* scenario system strength and inertia results for the original 2021 *System Security Reports* were based on a limited number of market modelling runs. The *Step Change* scenario is based on a much wider range of market modelling iterations for each year of the study period, capturing multiple reference years and generator outage and maintenance patterns. This better captures the variability in weather patterns and generator outage and maintenance patterns, and hence gives better regard of typical dispatch patterns as per 5.20B.3 of the National Electricity Rules (NER). Generator maintenance patterns are particularly impactful for system strength studies given that maintenance timing has historically coincided with times of minimum demand on the system, and this is also typically when system strength issues are exacerbated. Appendix A1 provides further information about the market modelling.

1.2 Scope of this update

AEMO is required to report on key system security needs for each region of the National Electricity Market (NEM) under NER 5.20, including system strength, inertia, and NSCAS. For system strength and inertia, this includes assessing the minimum requirements and determining whether a shortfall is expected to occur over the coming five-year period[8].

[7] Origin Energy, 'Origin proposes to accelerate exit from coal-fired generation', February 2022. Available at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

[8] Fuller details about these regulatory obligations are available in Section 2 of AEMO's 2021 *System Security Reports*, December 2021. Available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/system-security-reports.pdf?la=en.

This update reports on AEMO's re-assessment of the system strength and inertia elements of the 2021 *System Security Reports* that are expected to change as a result of the material changes described in Section 1.1 of this report. As such:

- The minimum system strength and inertia requirements for each region are unchanged from December 2021. These requirements comprise the determination of fault level nodes and associated minimum three phase fault level requirements, and the inertia sub-networks and associated minimum threshold level and secure operating level of inertia.
- AEMO has assessed and declares updated system strength and inertia shortfalls over the five-year horizon, against the existing requirements for each region, as a result of the changes described in Section 1.1 of this report. These assessments are undertaken consistent with NER 5.20C.2 and 5.20B.3.
- The revised shortfalls are declared for the period to December 2026. However, modelling has been undertaken based on financial years. As only two months remain in the 2021-22 financial year, this update presents data from 2022-23 to 2026-27.
- The Tasmania region system strength and inertia results were not re-assessed, as AEMO does not expect either of the changes described in Section 1.1 to affect the Tasmanian shortfall assessments. It is noted that the 2021 *System Security Reports* already declared shortfalls which include reaching the current floor of minimum synchronous machines online.
- AEMO has not yet re-assessed other system security impacts, under the NSCAS framework, that may change as a result of the Eraring Power Station announcement. AEMO expects to publish a further NSCAS assessment later in 2022.

Further information on the generator, network and market modelling assumptions applied in this report can be found in Appendix A1. Appendices A2 and A3 provide information about the electromagnetic transient (EMT) studies which informed the assessment of the system strength and inertia requirements.

1.3 Relation to other AEMO planning documents

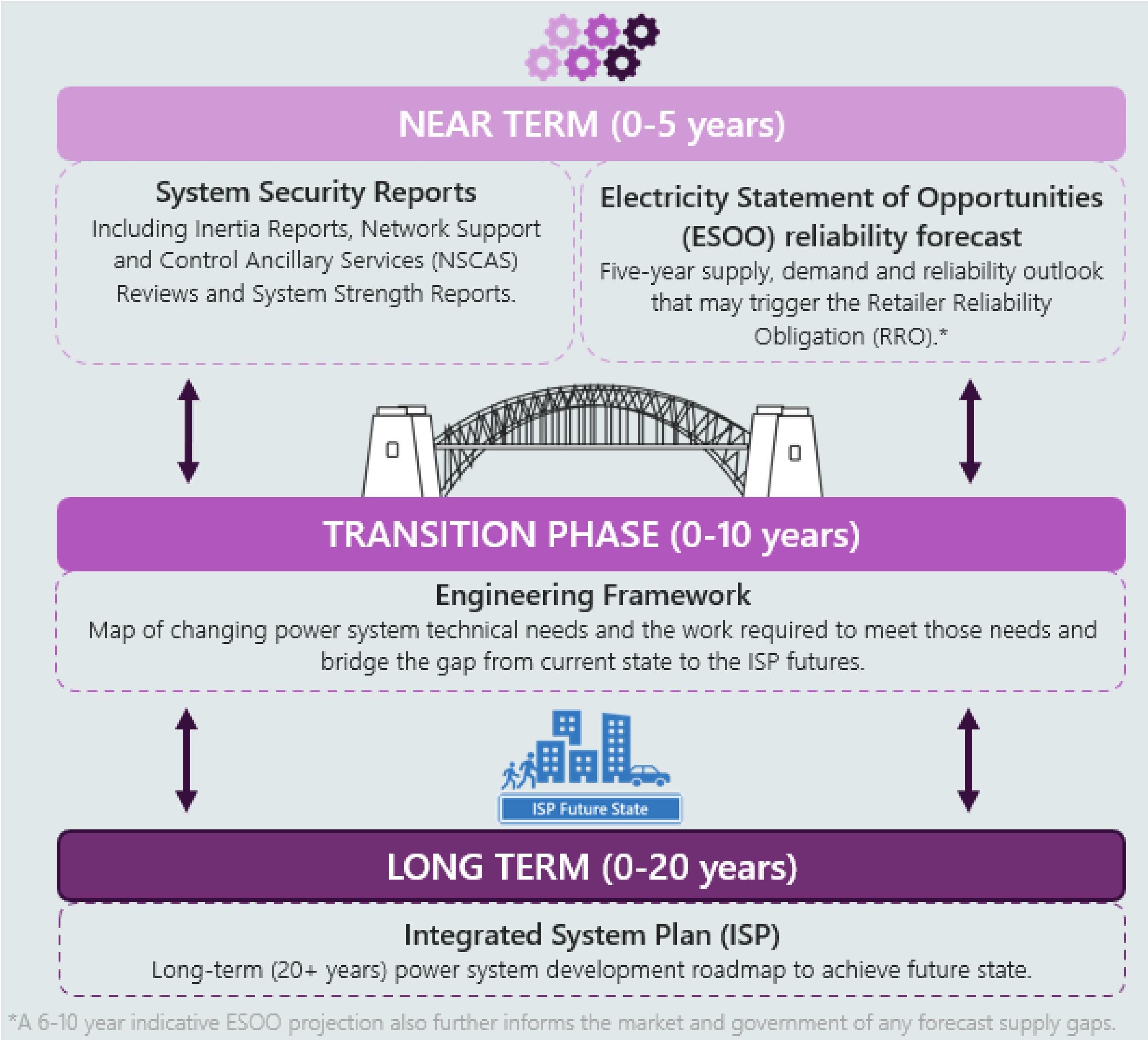
The annual system strength, inertia and NSCAS reviews draw inputs from a number of related AEMO reports and processes, and in turn inform and underpin a range of reports and processes owned by AEMO and TNSPs.

Figure 2 shows the system security assessments in this report in relation to other key AEMO forecasting and planning documents and processes.

AEMO has also recently published an update to the 2021 *Electricity Statement of Opportunities* (ESOO)[9] for the NEM, to capture the impact of the potential early retirement of Eraring Power Station in August 2025.

[9] Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Figure 2 Relationship between AEMO planning documents



2 New South Wales

The *Step Change* scenario forecasts a greater decline in synchronous generation online, greater VRE penetration and slightly higher minimum operational demand in New South Wales compared to the *Progressive Change* scenario.

System strength shortfalls are declared at Sydney West and Newcastle and are projected to occur one year earlier than forecast in the original 2021 *System Security Reports*.

Inertia in New South Wales is expected to decline below the secure operating level close to the end of the five-year outlook period. As islanding of New South Wales from the remainder of the NEM is not considered likely, AEMO is not declaring a shortfall at present, but intends to undertake additional assessments to consider the available inertia in adjacent regions that may form a separate island within the NEM.

Holistic and innovative power system design and operation will be needed to navigate this energy transition as traditional synchronous generation behaviour changes and renewable energy zones are urgently prioritised and delivered.

This section provides:

- Supply and demand outlook (Section 2.1).
- Assessment of system strength shortfalls (Section 2.2).
- Assessment of inertia shortfalls (Section 2.3).

2.1 Supply and demand outlook

New South Wales is forecast to experience a slightly higher minimum operational demand (sent-out[10]) under the *Step Change* scenario compared to the *Progressive Change* scenario, as shown in Figure 3. The figure shows 90% probability of exceedance (POE) and 50% POE forecasts for both scenarios[11].

Under *Step Change* there is over 300 megawatts (MW) more large-scale VRE installed in New South Wales compared to *Progressive Change* by 2026-27. There is also additional coal unit retirement projected, as shown in Figure 4, including the recent announcement by Origin Energy[12] for the potential early retirement of Eraring Power Station.

[10] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

[11] A 50% POE forecast is expected statistically to be met or exceeded one year in two, and is based on average weather conditions. A 90% POE forecast for minimum demand is based on more extreme conditions that could be expected one year in 10.

[12] Origin Energy. 'Origin proposes to accelerate exit from coal-fired generation', February 2022. Available at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

Figure 3 Actual minimum demand and forecast 90% POE and 50% POE minimum operational demand (sent-out) for New South Wales, 2016-17 to 2026-27

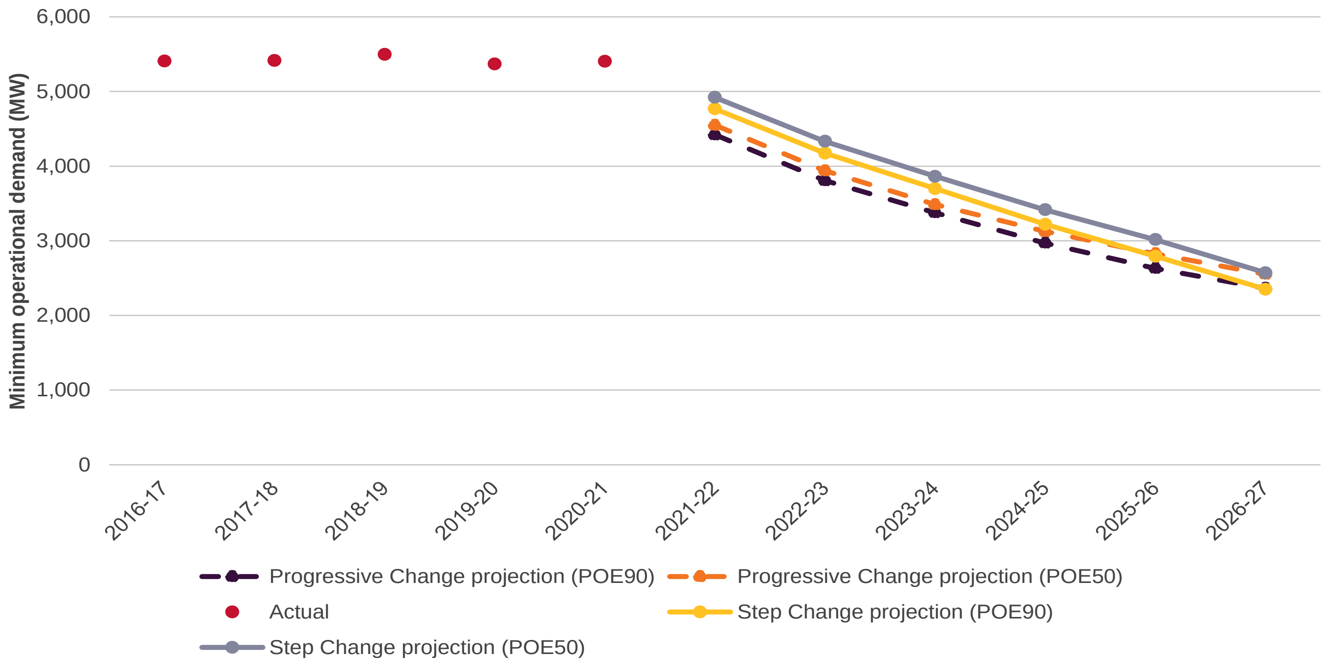
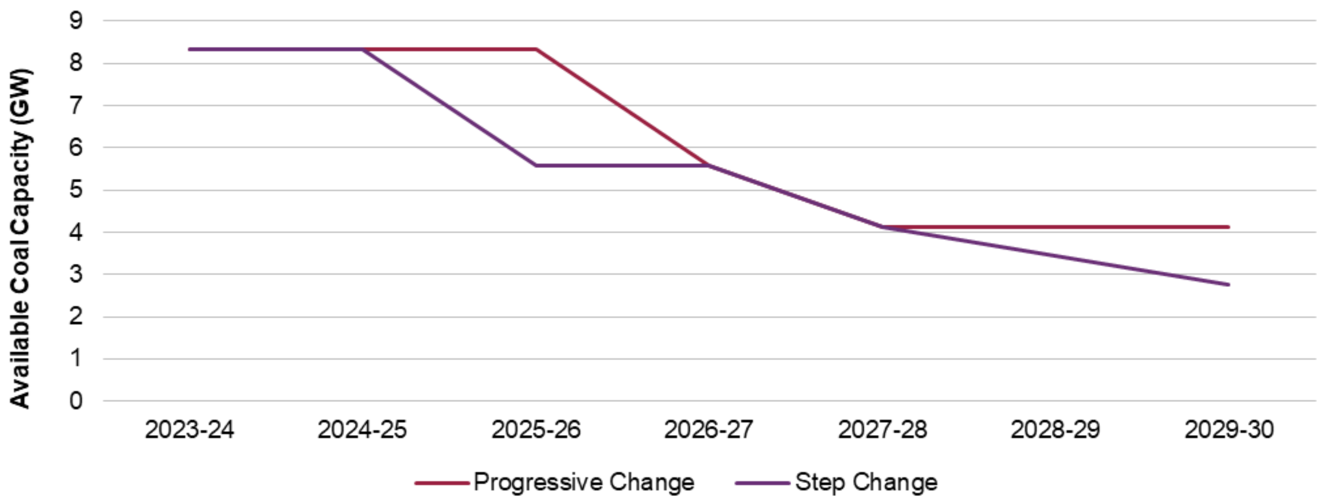


Figure 4 Projected retirement of coal units in New South Wales: *Step Change* versus *Progressive Change*, 2023-24 to 2029-30



2.2 2021 System strength assessment

2.2.1 Requirements

In this update the system strength requirements are unchanged from the original 2021 System Security Reports. See Table 2 for details.

AEMO and Transgrid have agreed that a new node should be declared at Buronga substation given concerns about system strength management in that area. Joint planning assessments are underway, and AEMO will declare the node and its minimum fault levels requirements later in 2022.

Table 2 New South Wales system strength requirements

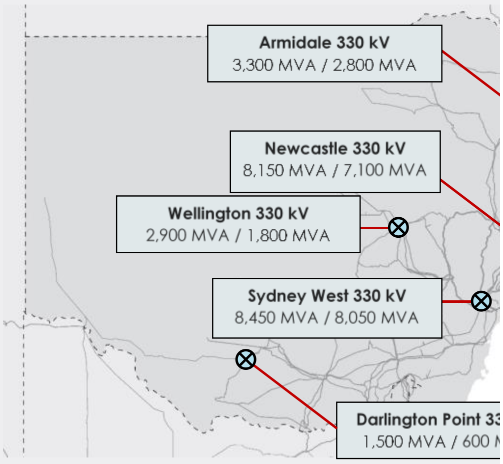
Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments [A]
		Pre-contingency	Post-contingency	
Armidale 330 kV	High IBR[13]	3,300	2,800	Per December 2020 determination.
Newcastle 330 kV	Synchronous generation centre	8,150	7,100	Per December 2020 determination.
Wellington 330 kV	High IBR	2,900	1,800	Per December 2020 determination.
Sydney West 330 kV	Metropolitan load centre	8,450	8,050	Per December 2020 determination.
Darlington Point 330 kV	High IBR; Remote from synchronous generation	1,500	600	Per December 2020 determination.

A. 2020 *System Strength and Inertia Report*, at aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[13] The term inverter-based resources (IBR) is used in the System Strength Requirements Methodology to refer to variable renewable energy generation resources.

2.2.2 Outcomes

New South Wales



AEMO is declaring system strength shortfalls at both Newcastle and Sydney West under the *Step Change* scenario which forecasts earlier coal generator retirements, lower coal generator availability at certain times, and greater VRE penetration, compared to the *Progressive Change* scenario.

Other fault level nodes also see projected reductions in fault level under the *Step Change* scenario, although none below the minimum requirements.

AEMO considers that there will be a range of potential options to address system strength issues, including inverter-tuning, synchronous condensers, network augmentations, potentially batteries with advanced inverters, and contributions from existing market participants.

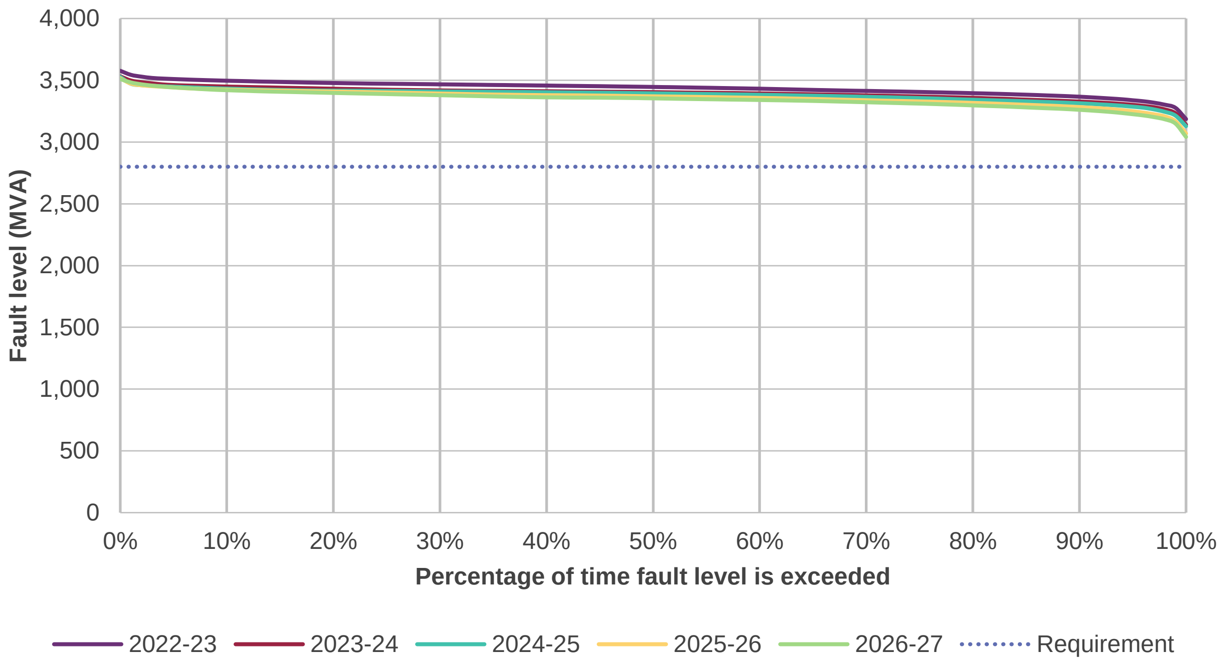
There may also be opportunity for innovative reductions in minimum requirements in New South Wales as part of system strength management.

Projections (*Step Change*) and shortfalls

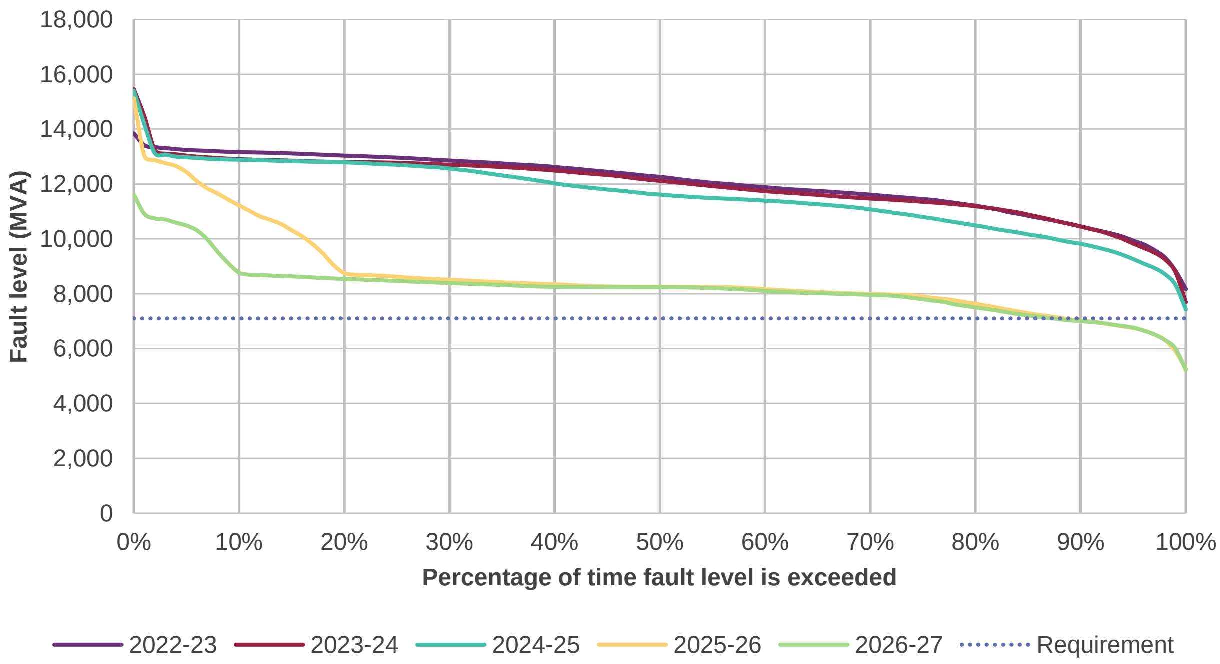
Node	Projected minimum three phase fault level for 99% of the time					Shortfalls and comments[A]
	2022-23	2023-24	2024-25	2025-26	2026-27	
Armidale 330 kV	3,277	3,234	3,215	3,169	3,158	No shortfall.
Newcastle 330 kV	8,848	8,802	8,333	5,910 (1,190 MVA shortfall)	6,009 (1,092 MVA shortfall)	A shortfall of 1,190 MVA is declared for 1 July 2025. AEMO will request that Transgrid provide system strength services to address the shortfall by 1 July 2025. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Wellington 330 kV	1,929	1,916	1,917	3,194	3,339	No shortfall.
Sydney West 330 kV	9,221	8,907	8,727	7,024 (1,026 MVA shortfall)	7,106 (944 MVA shortfall)	A shortfall of 1,026 MVA is declared for 1 July 2025. AEMO will request that Transgrid provide system strength services to address the shortfall by 1 July 2025. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Darlington Point 330 kV	695	707	692	722	739	No shortfall.

B. The system strength outcomes for New South Wales are assessed on a post-contingent basis.

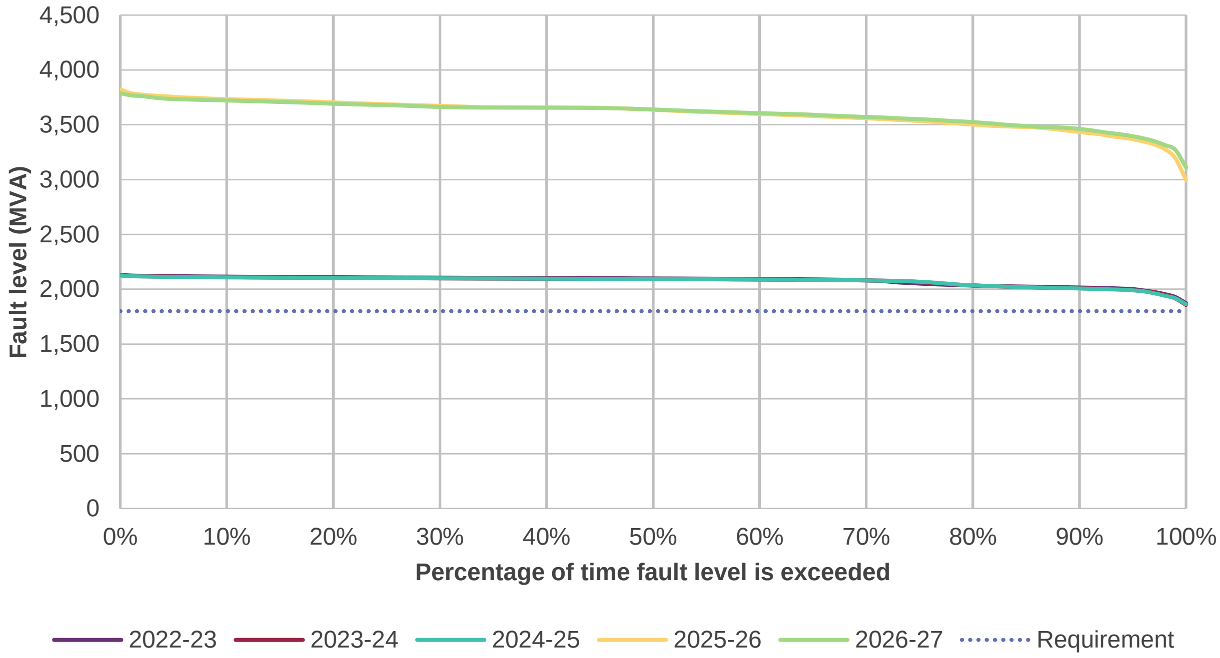
Armidale 330 kV



Newcastle 330 kV

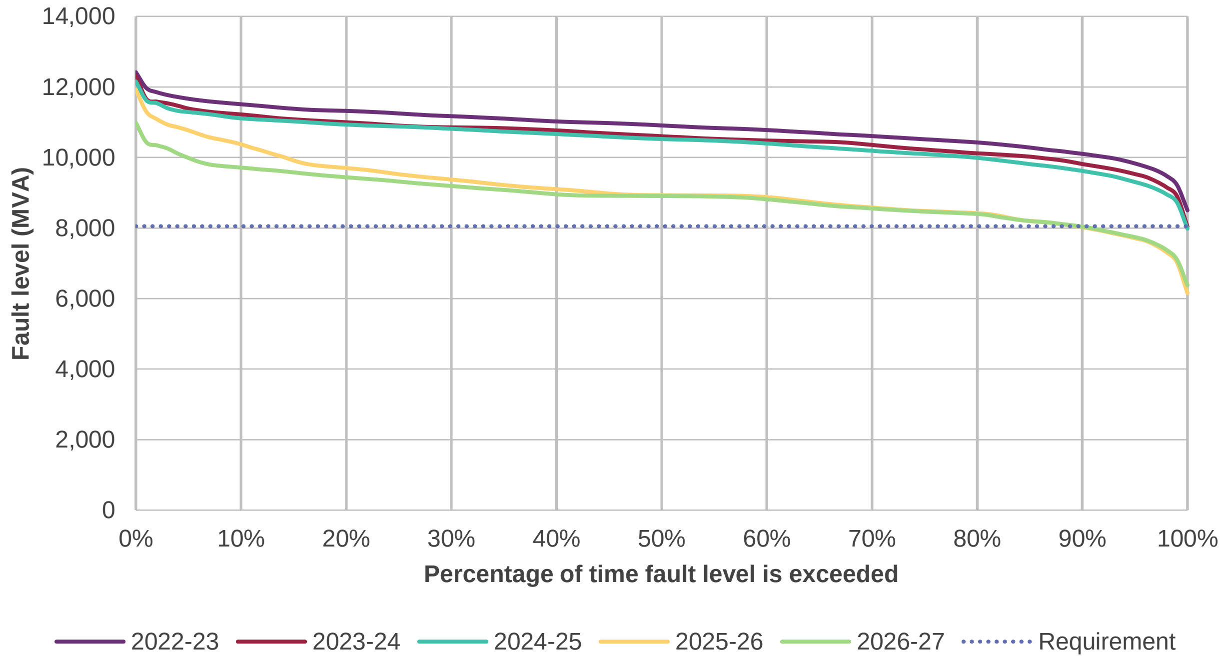


Wellington 330 kV

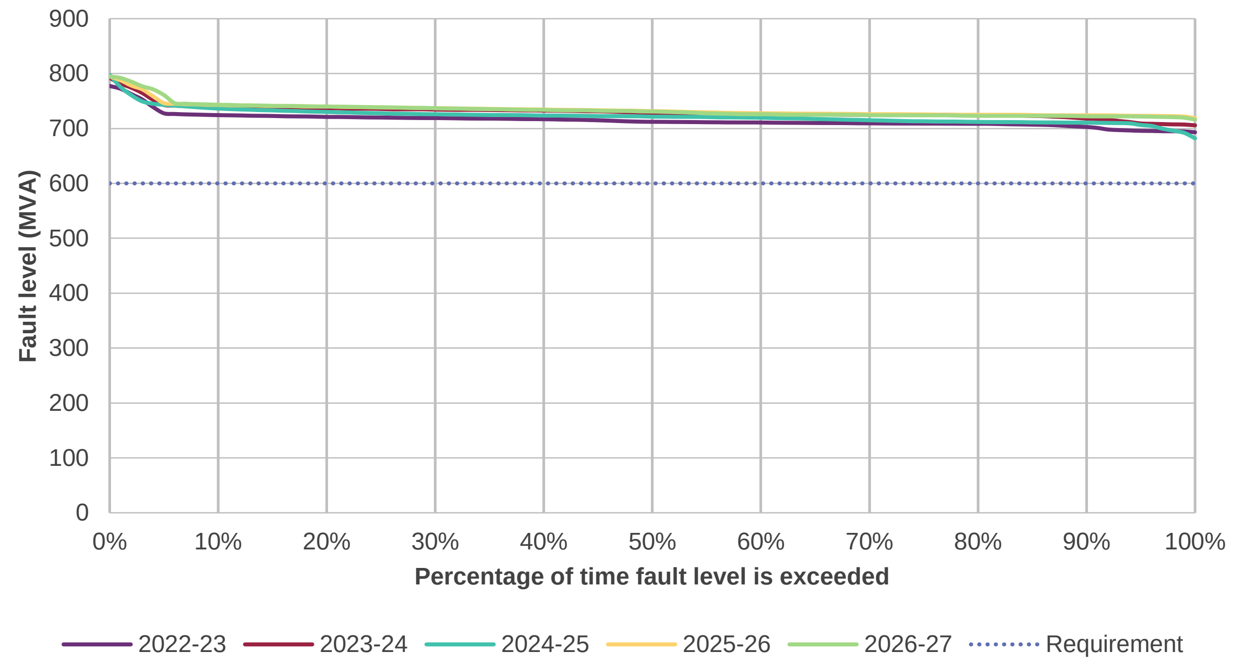


*Increases in fault level projections in the latter years are due to expected network augmentations associated with the nearby Central West Orana REZ. Over time the projections and requirements at Wellington will need to be re-assessed to consider the changing network and market conditions in this area.

Sydney West 330 kV



Darlington Point 330 kV



2.3 2021 Inertia assessment

New South Wales

Under the *Step Change* scenario, AEMO projects that inertia in New South Wales will decline over the coming five-year outlook period, including declining below the secure operating level in 2025-26. However, as New South Wales islanding from the remainder of the NEM is considered unlikely, no shortfall can be declared under the current application of the existing framework.

Despite the retirement of Liddell Power Station in 2023 and the announcement of the potential early retirement of Eraring Power Station in August 2025, no inertia shortfalls are declared because the region is not considered sufficiently likely to island from the rest of the NEM.

Inertia requirements

	2020	2021
Secure operating level of inertia (MWs)	12,500	12,500
Minimum operating level of inertia (MWs)	10,000	10,000
Net distributed PV trip (MW)	-	-
Risk of Islanding	Not likely	Not likely

The secure operating level and minimum operating level of inertia for New South Wales are held steady at the values determined in July 2018.

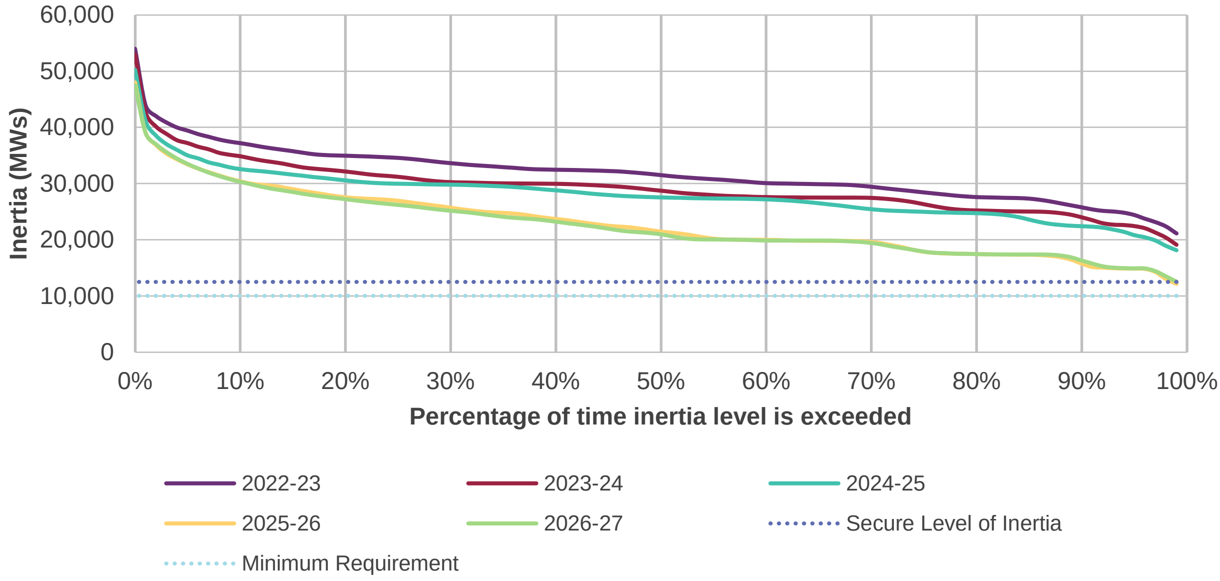
Declaration of any inertia shortfall for a region must also consider the likelihood of islanding. Islanding of New South Wales alone remains unlikely, consistent with AEMO's 2020 and 2018 assessments. This finding is largely driven by the diversity and number of AC interconnectors that exist between New South Wales and the adjacent regions. Net distributed PV trip has not been incorporated in this assessment, and the secure operating level is not provided as a ratio of synchronous inertia and fast frequency response or Fast FCAS, because islanding is not considered likely and so a shortfall will not be declared.

Inertia projections (*Step Change*)

	2022-23	2023-24	2024-25	2025-26	2026-27
Available inertia for 99% of the time (MWs)	21,146	19,089	18,116	12,175	12,522

New South Wales

Figure 5 Projected inertia for the five-year outlook, *Step Change* scenario, New South Wales



3 Queensland

Under the *Step Change* scenario, AEMO forecasts a greater decline in synchronous generation online, greater VRE penetration and higher minimum operational demand in Queensland compared to the *Progressive Change* scenario. A system strength shortfall at Gin Gin remains, and in this update the magnitude of the shortfall has increased in each of the five years.

More comprehensive modelling has meant that the region-wide inertia shortfall declared in December 2021 is rescinded, although the potential for a shortfall in 2026-27 remains, subject to future market assessments.

Innovative power system design techniques, deployment of new technologies, and flexible operational practices could be applied to address these urgent system security needs, as longer-term solutions are deployed aligned with the ongoing, broader transition of the system.

This section provides:

- Supply and demand outlook (Section 3.1).
- Assessment of system strength shortfalls (Section 3.2).
- Assessment of inertia shortfalls (Section 3.3).

3.1 Supply and demand outlook

Queensland is forecast to experience a higher minimum operational demand (sent-out[14]) over the next five years under the *Step Change* scenario compared to the *Progressive Change* scenario, as shown in Figure 6. The figure shows 90% POE and 50% POE forecasts for both scenarios[15].

Under *Step Change* there is over 2,500 MW more large scale VRE installed in Queensland compared to *Progressive Change* by 2026-27. There is also additional coal unit retirement projected, as shown in

Figure 7.

[14] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

[15] A 50% POE forecast is expected statistically to be met or exceeded one year in two, and is based on average weather conditions. A 90% POE forecast for minimum demand is based on more extreme conditions that could be expected one year in 10.

Figure 6 Actual minimum demand and forecast 90% POE and 50% POE minimum operational demand (sent-out) for Queensland, 2016-17 to 2026-27

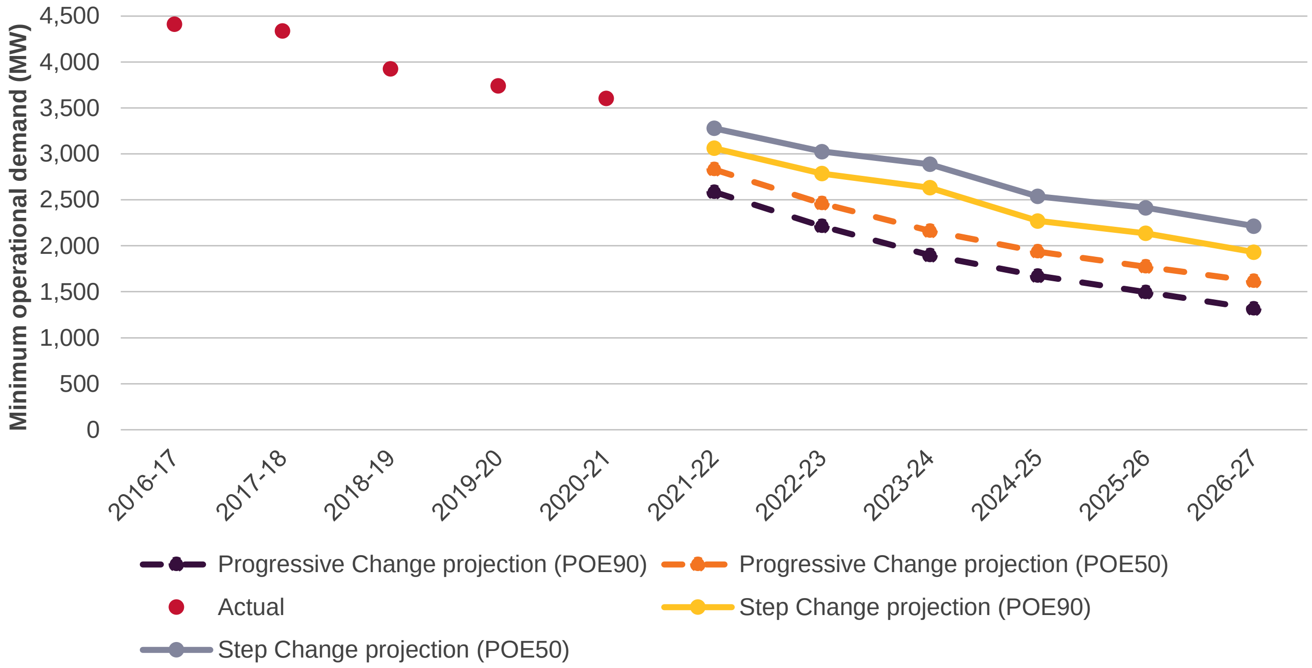
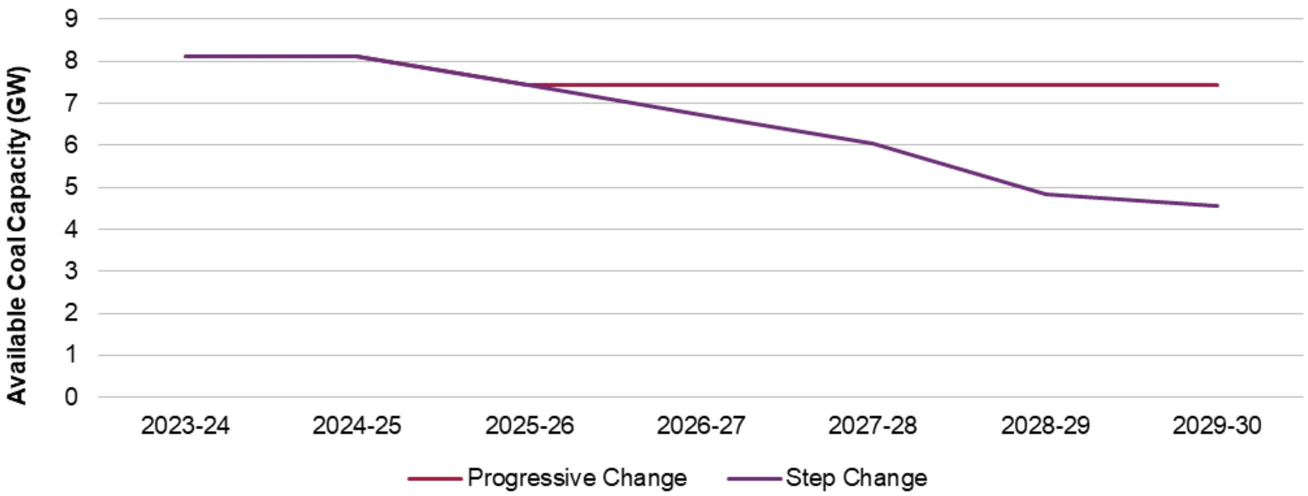


Figure 7 Projected retirement of coal units in Queensland: *Step Change* versus *Progressive Change*, 2023-24 to 2029-30



3.2 2021 System strength assessment

3.2.1 Requirements

In this update, the system strength requirements are unchanged from the original 2021 System Security Reports. See Table 3 for details.

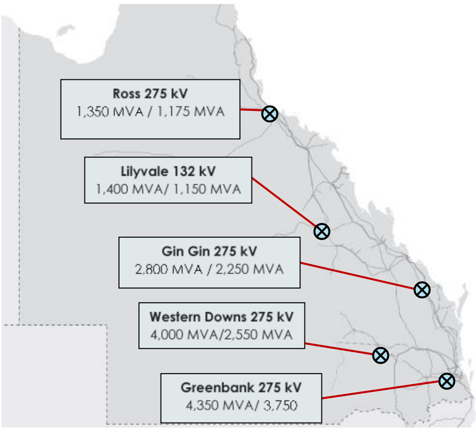
Table 3 Queensland system strength requirements

Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments
		Pre-contingency	Post-contingency	
Ross 275 kV	High IBR; Remote from synchronous generation	1,350	1,175	Per June 2021 declaration [A].
Lilyvale 132 kV	High IBR; Remote from synchronous generation	1,400	1,150	Per December 2020 determination[B].
Gin Gin 275 kV	Synchronous generation centre	2,800	2,250	Per December 2020 determination[B].
Greenbank 275 kV	Metropolitan load centre	4,350	3,750	Per December 2020 determination[B].
Western Downs 275 kV	Synchronous generation centre	4,000	2,550	Per December 2020 determination [B].

A. 2021 Notice of change to system strength requirement and shortfall at Ross, available via aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.
B. 2020 *System Strength and Inertia Report* and 2021 *System Security Reports*, available via aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

3.2.2 Outcomes

Queensland



AEMO is increasing the size of the declared system strength shortfall at Gin Gin due to the projected decline in the number of synchronous machines online in central Queensland in response to declining minimum demand and increasing VRE and distributed PV.

Other fault level nodes also see projected reductions in fault level under the *Step Change* scenario, although none below the minimum requirements.

AEMO considers that there will be a range of potential options to address system strength issues, including inverter-tuning, synchronous condensers, network augmentations, potentially batteries with advanced inverters, and contributions from existing market participants.

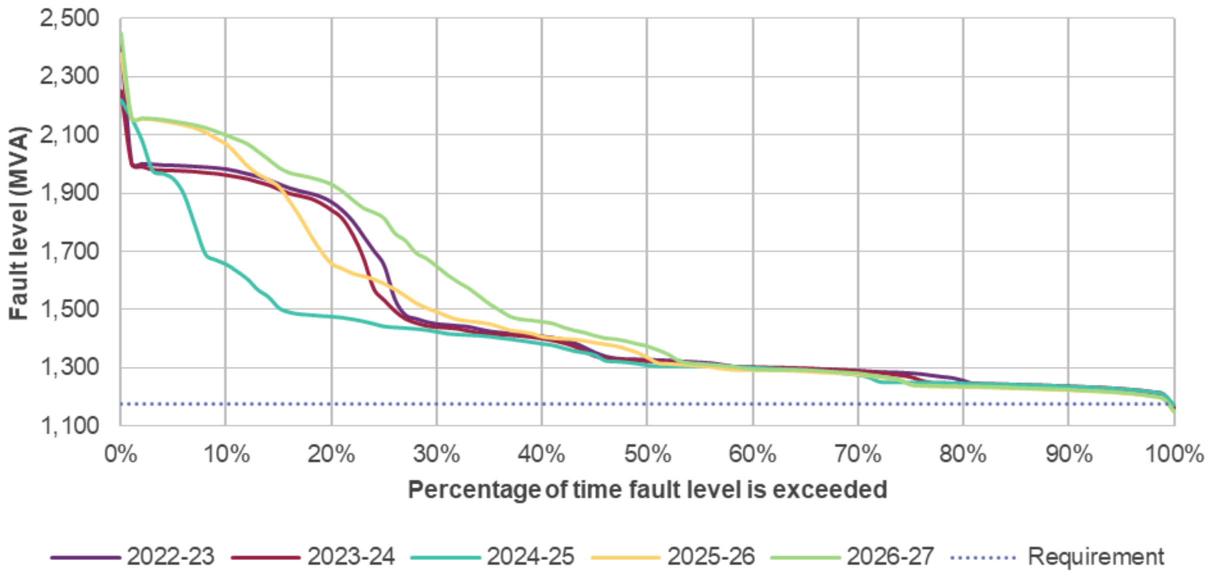
There may also be opportunity for innovative reductions in minimum requirements in Queensland as part of system strength management.

Projections (*Step Change*) and shortfalls

Node	Projected minimum three phase fault level for 99% of the time					Shortfalls and comments [A]
	2022-23	2023-24	2024-25	2025-26	2026-27	
Ross 275 kV	1,205	1,209	1,208	1,195	1,192	No shortfall. In June 2021, the requirement was changed and the previous shortfall closed, following inverter-tuning of local generators.
Lilyvale 132 kV	1,206	1,214	1,213	1,194	1,190	No shortfall.
Gin Gin 275 kV	2,217 (33 MVA shortfall)	2,206 (44 MVA shortfall)	2,200 (50 MVA shortfall)	2,173 (77 MVA shortfall)	2,160 (90 MVA shortfall)	A shortfall range of 33 to 90 MVA is declared for the period. AEMO will request that Powerlink provide system strength services to address the shortfall by 31 March 2023. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Greenbank 275 kV	4,841	4,798	4,729	4,759	4,278	No shortfall.
Western Downs 275 kV	2,944	2,935	2,916	2,924	2,720	No shortfall.

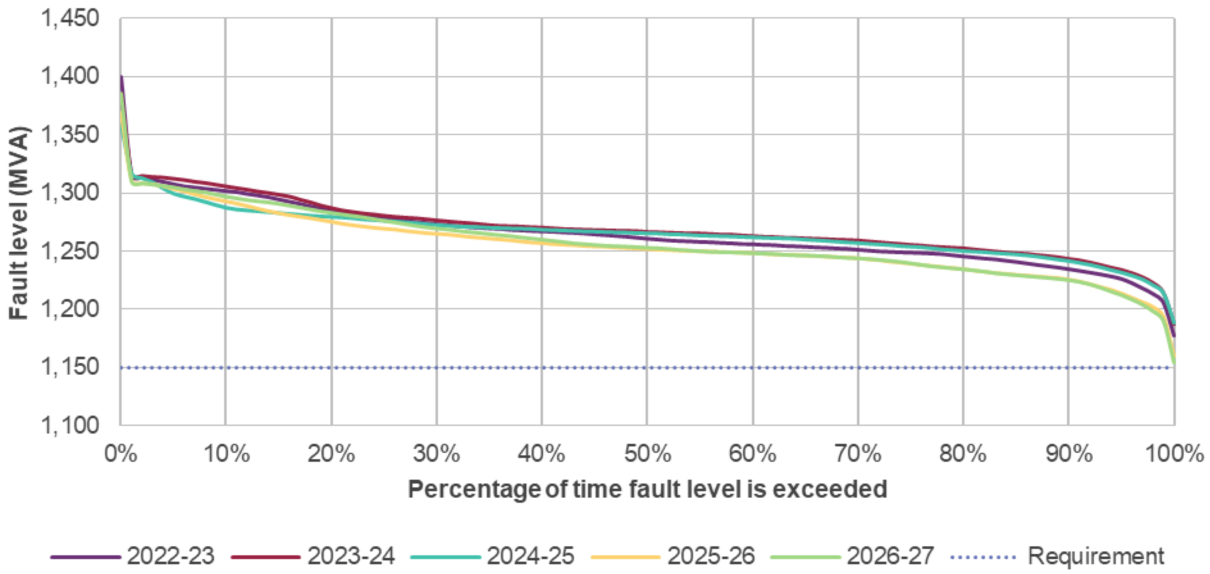
A. The system strength outcomes for Queensland are assessed on a post-contingent basis.

Ross 275 kV

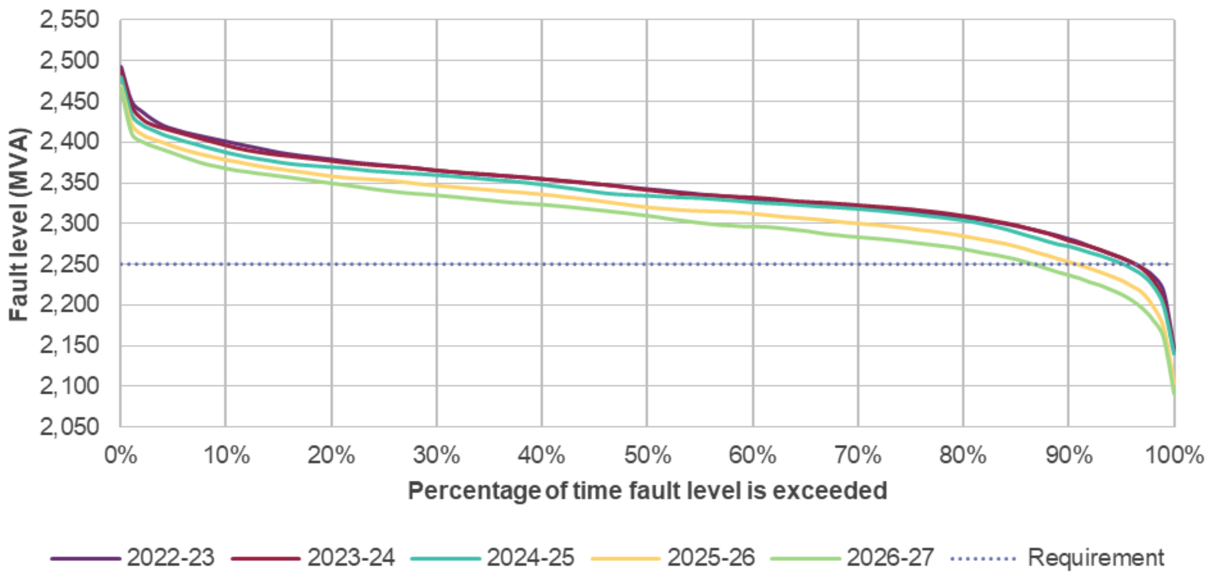


*In 2021, Powerlink and local generators delivered inverter-tuning solutions resulting in a changed minimum requirement and closed system strength shortfall.

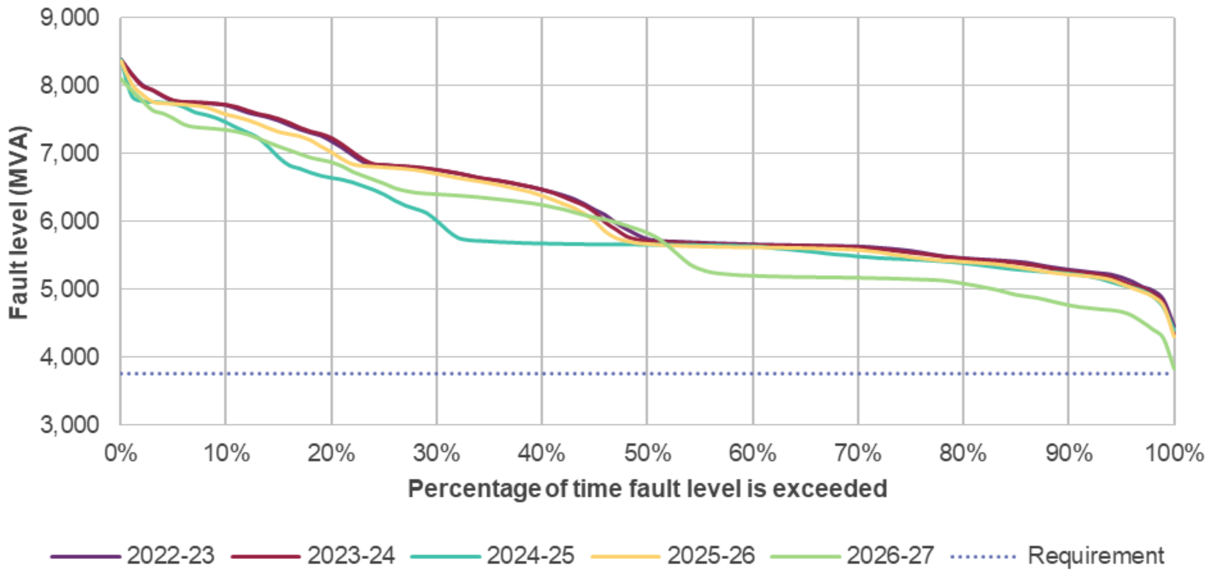
Lilyvale 132 kV



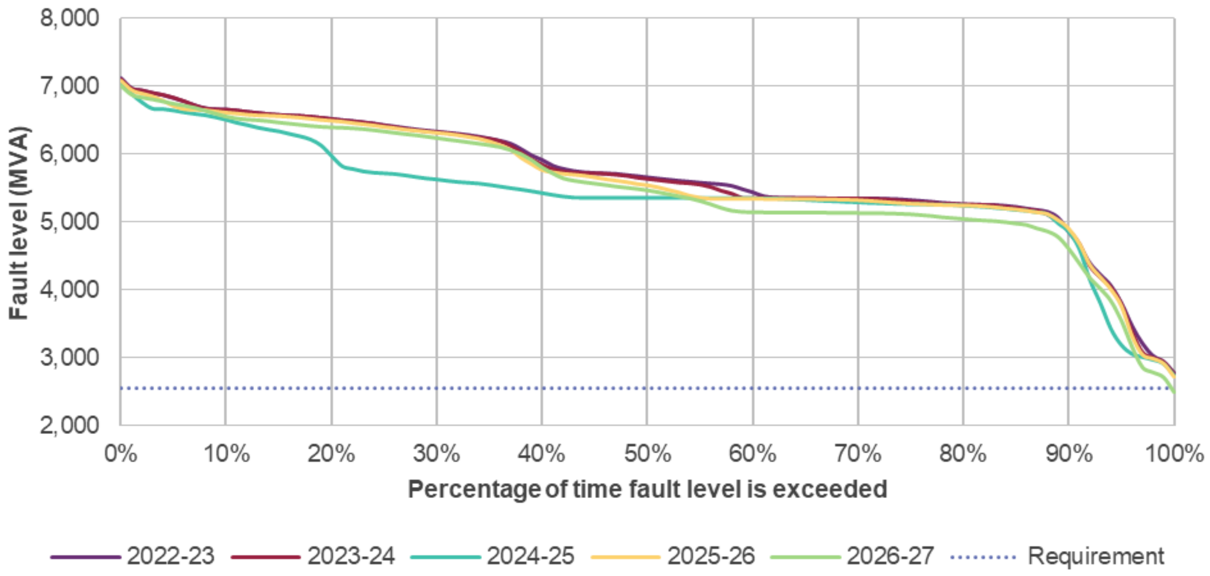
Gin Gin 275 kV



Greenbank 275 kV



Western Downs 275 kV



3.3 2021 Inertia assessment

Queensland

AEMO is removing the shortfall declared against the secure operating level of inertia in the December 2021 report for the Queensland region, in response to the *Step Change* results, however the possibility remains for a future shortfall equal to 8,384 MWs for 2026-27, subject to future market assessments.

For the period to 2026-27, AEMO has assessed that the minimum threshold level of inertia will be met. A potential shortfall is observed against the secure operating level of inertia for 2026-27, but is not declared in this update due to improved outlook for available fast frequency control ancillary services. A potential future shortfall remains a possibility as the market changes. As discussed in the 2021 *System Security Reports*[16], the inertia framework only covers shortfalls occurring for more than 1% of the time. To manage issues outside of this framework, AEMO's previous recommendations of emergency last resort measures remain unchanged[17 18].

Inertia requirements

	2020	2021	
Secure operating level of inertia (MWs) (and related MW Fast FCAS)	14,800 MWs	24,100 MWs at 390 MW Fast FCAS 16,600 MWs at 455 MW Fast FCAS	The secure operating level in Queensland is dependent on the Fast FCAS available and is also likely to be able to be reduced by any fast frequency response that may be made available through inertia support services or other means. The requirements determined in 2021 do not assume fast frequency response from utility-scale batteries as part of the typical dispatch used to set the requirements. Figure 8 shows the relationship between inertia required and available Fast FCAS. Appendix A3 details the calculation method for determining net distributed PV disconnection size.
Minimum operating level of inertia (MWs)	11,900	11,900	
Net distributed PV trip (MW)	130	270	
Risk of islanding	Likely	Likely	

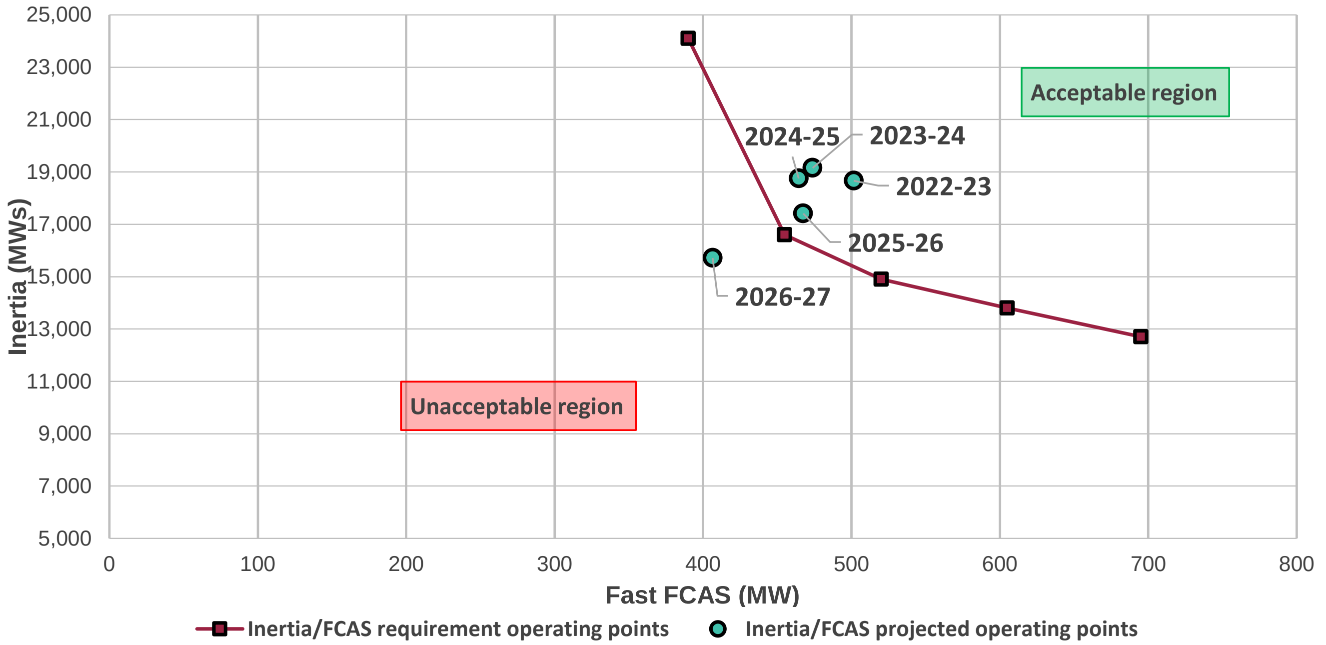
[16] AEMO, *2021 System Security Reports*, December 2021. Appendix A5. Available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/system-security-reports.pdf?la=en.

[17] AEMO, *2020 Electricity Statement of Opportunities*, August 2020. Section 6.1. Available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2021/2021-nem-esoo.pdf?la=en&hash=D53ED10E2E0D452C79F97812BDD926E.

[18] AEMO, *2021 Electricity Statement of Opportunities,* August 2021. Section 7. Available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en.

Queensland

Figure 8 2021 secure operating level of inertia requirement and five-year projections of inertia and fast FCAS for 99th percentile, Queensland A, B, C, D

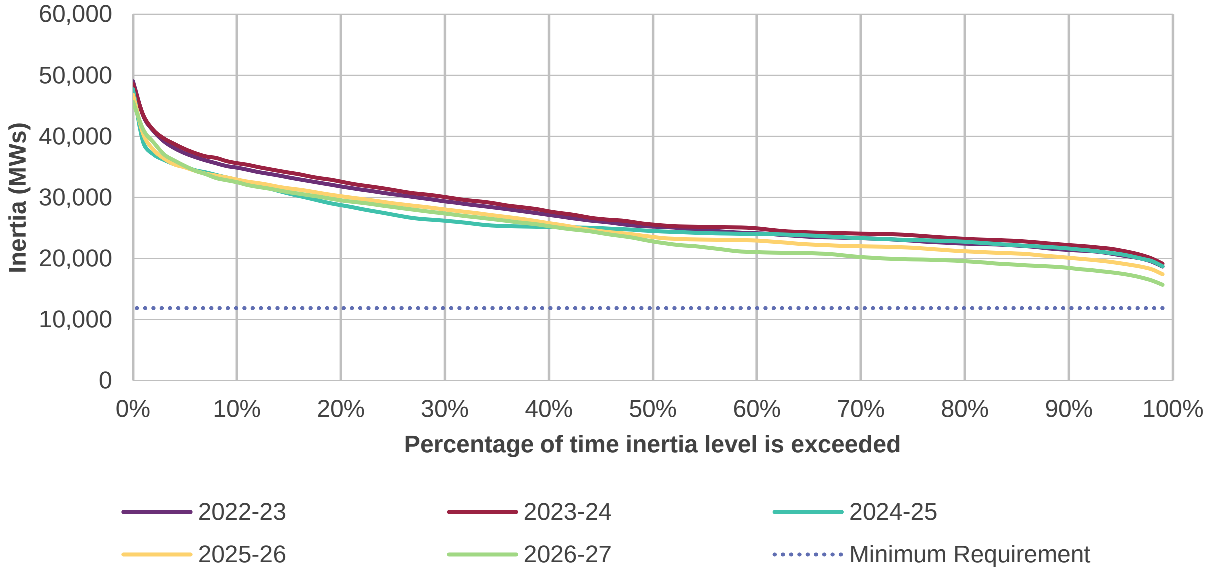


C. The figure represents the relationship between the level of inertia required against the amount of Fast FCAS required for each level of inertia. The Fast FCAS does not include any fast frequency response from utility-scale batteries or other inverter-based resources.
D. Square data points show the operating points which have been modelled and provide a secure system. A line is drawn between the operating points to broadly indicate where the system may be considered to be secure.
E. The area above and to the right of the purple line is acceptable from a system security perspective, and the area below and to the left is unacceptable.
F. The projection for inertia and Fast FCAS for each year in the five-year outlook period is shown with a green circle (99th percentile of time, Step Change scenario). The projections can include both synchronous generating units and committed utility-scale batteries, noting that the impact of any fast frequency response (as opposed to Fast FCAS) in the projections is not displayed on this inertia-Fast FCAS figure.

Inertia projections (*Step Change*)					
	2022-23	**2023-24**	**2024-25**	**2025-26**	**2026-27**
Available inertia for 99% of the time (MWs)	18,665	19,158	18,754	17,413	15,716
Fast FCAS projected available at 99th percentile (MW)	502	474	465	468	407
Inertia shortfall against secure operating level (MWs)	None	None	None	None	8,384 Assessed as 'potential' rather than declared, given potentially large market, network and regulatory changes by this date.

Inertia projections (*Step Change*)

Figure 9 Projected inertia for the five-year outlook, *Step Change* scenario, Queensland [A]



A. Inertia projections are shown against the minimum threshold level of inertia. The secure operating level is not shown as a single value because it is a function of available inertia and Fast FCAS.

4 South Australia

Under the *Step Change* scenario, minimum demand in South Australia is slightly higher, with more VRE penetration, but no change to synchronous generator retirement when compared to the *Progressive Change* scenario. The inertia shortfall declared in 2021 remains the same size and with the same timing.

No system strength shortfalls were identified, with ElectraNet's four new synchronous condensers now delivering both system strength and inertia for the region.

A range of innovative solutions will be needed to address the system security needs identified in South Australia as the energy transformation continues.

This section provides:

- Supply and demand outlook (Section 4.1).
- Assessment of system strength shortfalls (Section 4.2).
- Assessment of inertia shortfalls (Section 4.3).

4.1 Supply and demand outlook

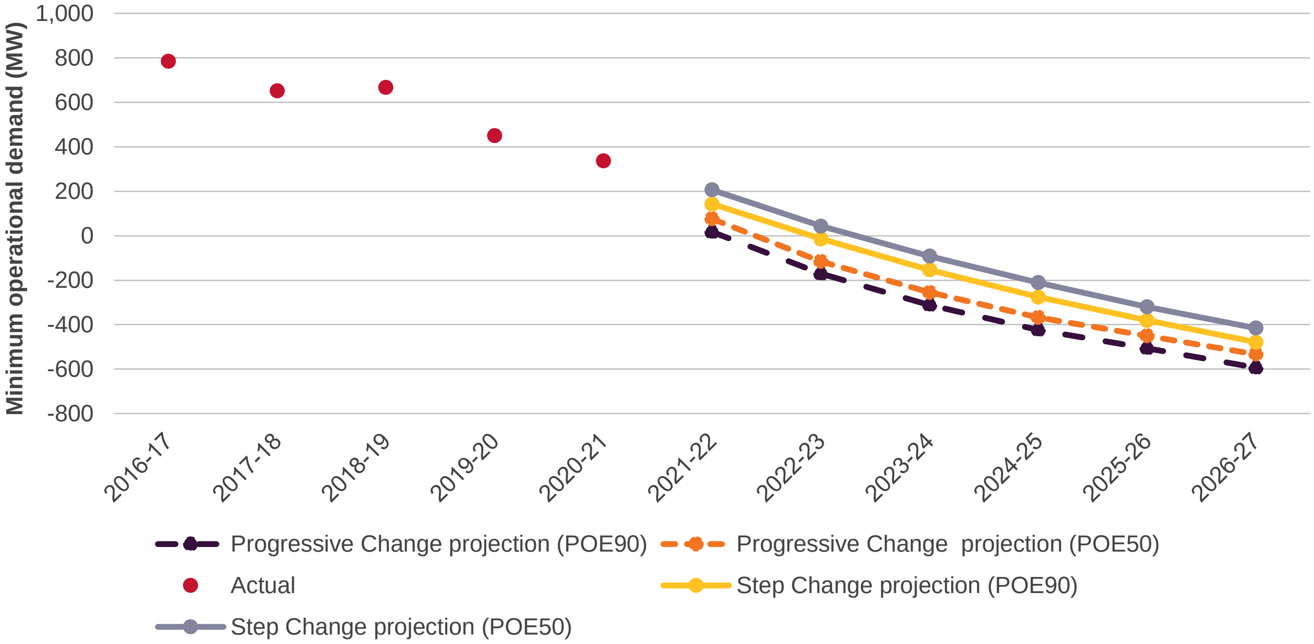
South Australia is forecast to experience a higher minimum operational demand (sent-out[19]) over the next five years under the *Step Change* scenario, compared to the *Progressive Change* scenario, as shown in Figure 10. The figure shows 90% POE and 50% POE forecasts for both scenarios[20].

Under *Step Change* there is over 800 MW more VRE installed in South Australia compared to *Progressive Change* by 2026-27. The *Step Change* scenario does not see any additional synchronous units retire in South Australia over the five-year outlook compared to *Progressive Change*.

[19] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

[20] A 50% POE forecast is expected statistically to be met or exceeded one year in two, and is based on average weather conditions. A 90% POE forecast for minimum demand is based on more extreme conditions that could be expected one year in 10.

Figure 10 Actual minimum demand and forecast 90% POE and 50% POE minimum operational demand (sent-out) for South Australia, 2016-17 to 2026-27



4.2 2021 System strength assessment

4.2.1 Requirements

In this update. the system strength requirements are unchanged from the original 2021 *System Security Reports*. See Table 4 for details.

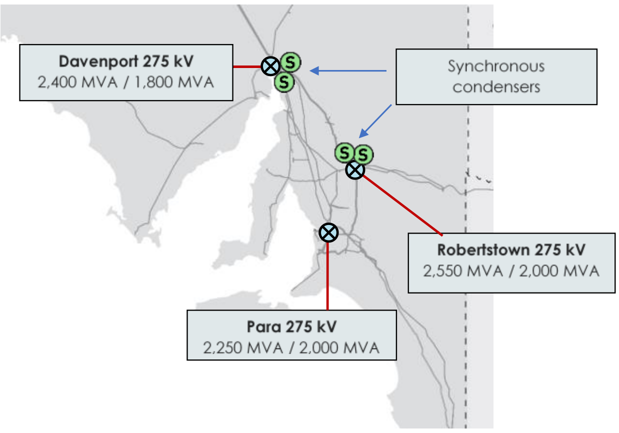
Table 4 South Australia system strength requirements

Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments [A]
		Pre-contingency	Post-contingency	
Davenport 275 kV	High IBR; Remote from synchronous generation	2,400	1,800	Per December 2020 determination.
Para 275 kV	Metropolitan load centre; Remote from synchronous generation	2,250	2,000	Per December 2020 determination.
Robertstown 275 kV	High IBR; Remote from synchronous generation	2,550	2,000	Per December 2020 determination.

A. 2020 *System Strength and Inertia Report*, at aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

4.2.2 Outcomes

South Australia



Although the South Australia fault level nodes see projected reductions in fault level under the *Step Change* scenario, none are below the minimum requirements.

The four new synchronous condensers installed in South Australia will meet the system strength requirements for the outlook period. Project EnergyConnect will further improve system strength once commissioned.

The analysis incorporates the AEMO planning assumption that at least two large synchronous generating units remain online for system security purposes until the commissioning and testing of Project EnergyConnect is complete[21].

Project EnergyConnect is modelled for completion by 2024 (Stage 2) with full capacity expected to be available after inter-network testing in July 2025.

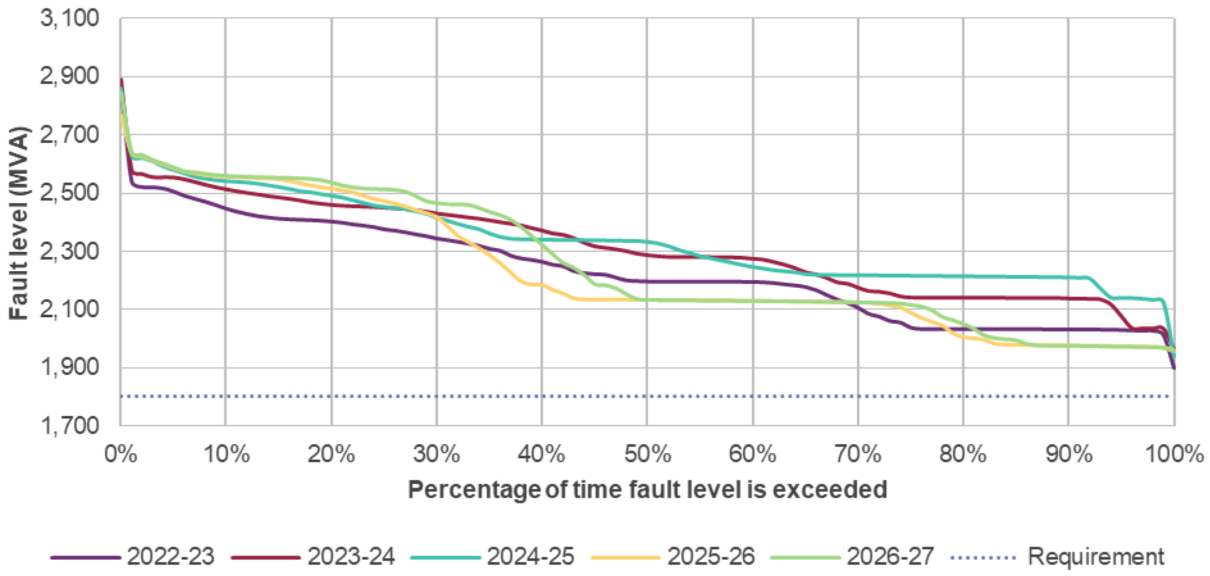
Projections (*Step Change*) and shortfalls

Node	Available minimum three phase fault level for 99% of the time					Shortfalls and comments A
	2022-23	2023-24	2024-25	2025-26	2026-27	
Davenport 275 kV	2,013	2,033	2,125	1,969	1,970	No shortfall.
Para 275 kV	2,869	2,967	3,101	2,286	2,282	No shortfall.
Robertstown 275 kV	2,433	2,448	2,853	2,803	2,814	No shortfall.

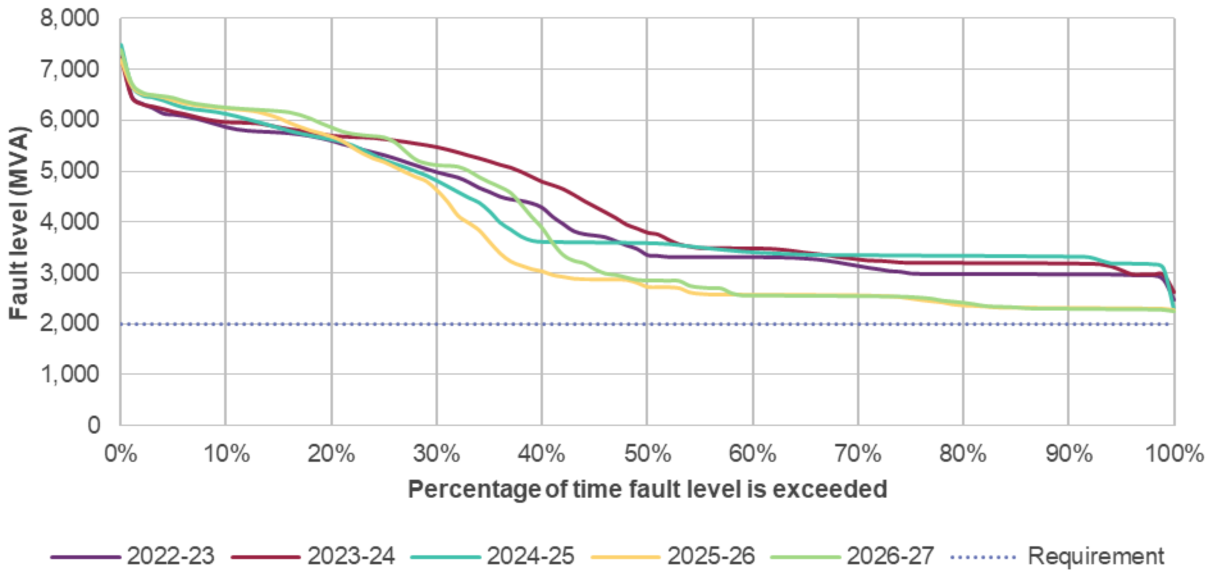
A. The system strength requirements for South Australia are assessed on a post-contingent basis.

[21] AEMO is continuing to assess ongoing power system requirements for South Australia, including the requirement to keep two synchronous generating units online, and will provide quarterly updates on this work plan in 2022.

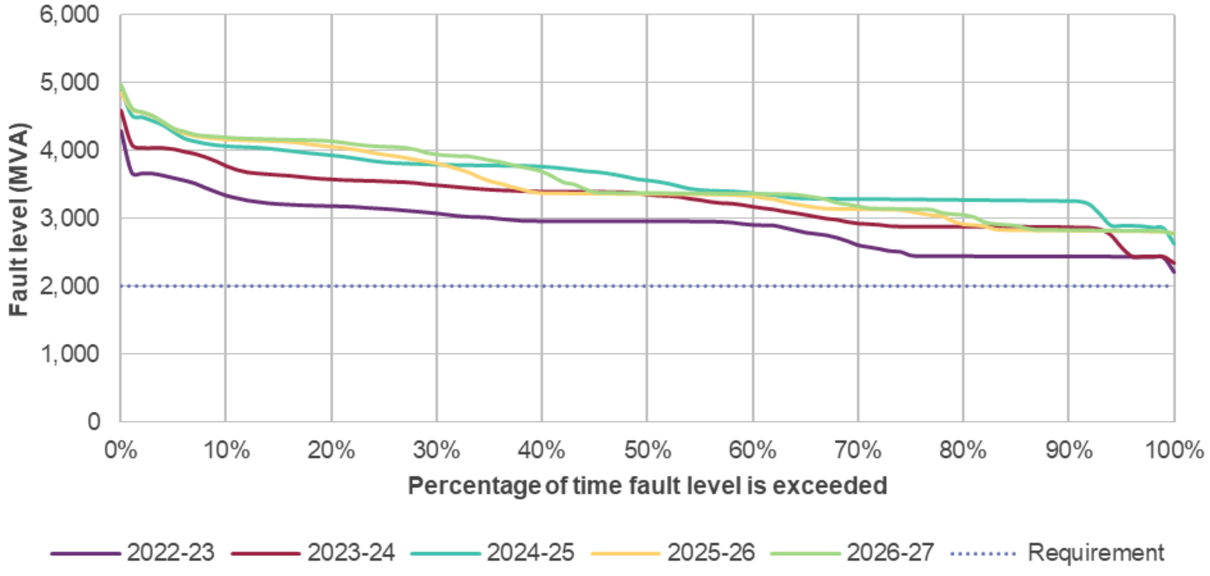
Davenport 275 kV



Para 275 kV



Robertstown 275 kV



4.3 2021 Inertia assessment

South Australia

The previously declared inertia shortfalls in South Australia remain, consistent with the original 2021 System Security Reports. This includes a shortfall out to 30 June 2022, and a shortfall from 1 July 2023 until the completion of inter-network testing of Project EnergyConnect, against the secure operating level of inertia in the South Australia region. The shortfall out until completion of Project EnergyConnect is for approximately 28,800 MWs, although it is likely to be more practicable to fill this shortfall with inertia support activities such as fast frequency response (FFR) equivalent to 360 MW.

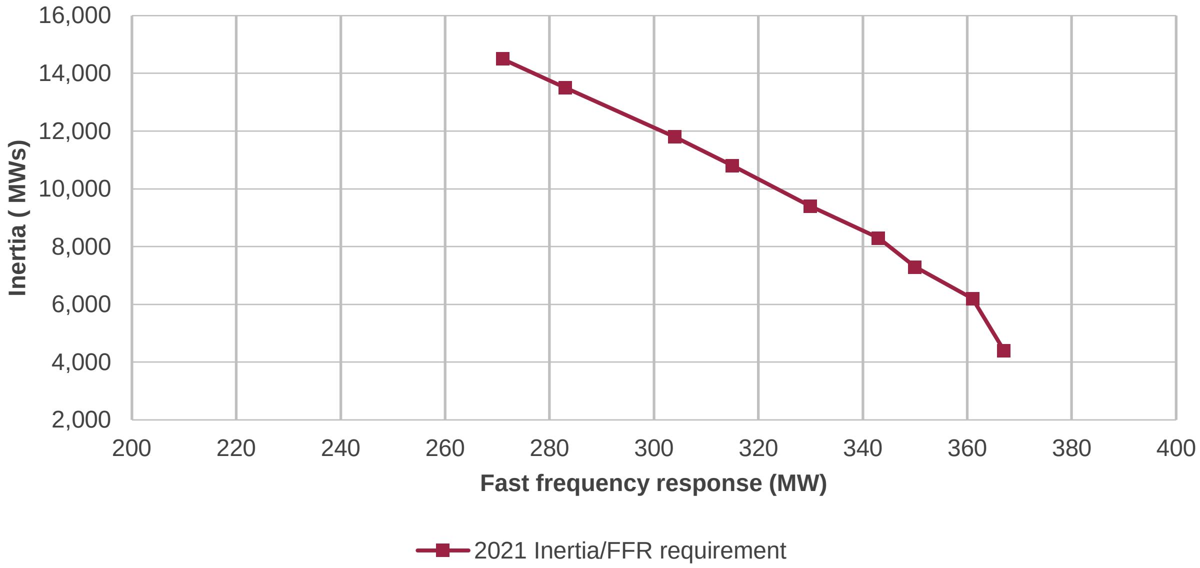
For the period to 2026-27, AEMO has assessed that the minimum threshold level of inertia will be met. However, a shortfall is projected against an updated secure operating level of inertia. Based on inertia projections for the *Step Change* scenario, 360 MW of inertia support activities such as FFR will be needed in South Australia (or equivalent amounts of synchronous inertia, approximately 28,800 MWs, or a combination of both). This shortfall is declared for the period from 1 July 2023 until the completion of inter-network testing of Project EnergyConnect, currently projected by end of July 2025[22]. In addition, the existing inertia shortfall declared in August 2020 persists until 30 June 2022, with ElectraNet continuing to pursue options to address this shortfall.

The end date for the shortfall could be affected by the provision of sufficient services through the establishment of very fast raise and lower ancillary services markets (market start due October 2023), or the completion of updates to a special protection scheme for South Australia (scheduled for July 2024). AEMO and ElectraNet will monitor these and other events and will re-assess the shortfall if required.

[22] With the competition in the inter-network testing of Project EnergyConnect, AEMO expects that South Australia will no longer be considered likely to island and therefore a shortfall will not be expected after that date.

Inertia requirements			
	2020	**2021**	AEMO originally declared an inertia shortfall as part of the 2018 National Transmission Network Development Plan and updated the secure operating level of inertia for South Australia in August 2020 and December 2020. These changes resulted from findings from the South Australia islanding events in early 2020, and due to increased distributed PV contingency size and implications of declining minimum demand in the region[23]. The secure operating level of inertia in South Australia is dependent on the amount of inertia support activities available, such as FFR. If more FFR (MW) is available then less synchronous inertia (MWs) is required. Figure 11 shows the relationship between inertia required and FFR provided. Appendix A3 details the calculation method for determining net distributed PV disconnection size. The current analysis incorporates an assumption that at least two synchronous generating units will remain online if South Australia is islanded, until completion of commissioning and inter-network testing of Project EnergyConnect[24]. This analysis also incorporates 70 MW (and 10 MWh) of capacity reservation provided to the South Australia Government by Hornsdale Power Reserve.
Secure operating level (MWs) (and related MW FFR)	14,390 MWs with 70 MW FFR	6,200 MWs with 360 MW FFR 4,400 MWs with 367 MW FFR	
Minimum threshold level of inertia (MWs)	4,400	4,400	
Net distributed PV trip (MW)	230	300	
Risk of islanding	Likely	Likely	

Figure 11 2021 secure operating level of inertia requirement, South Australia A, B



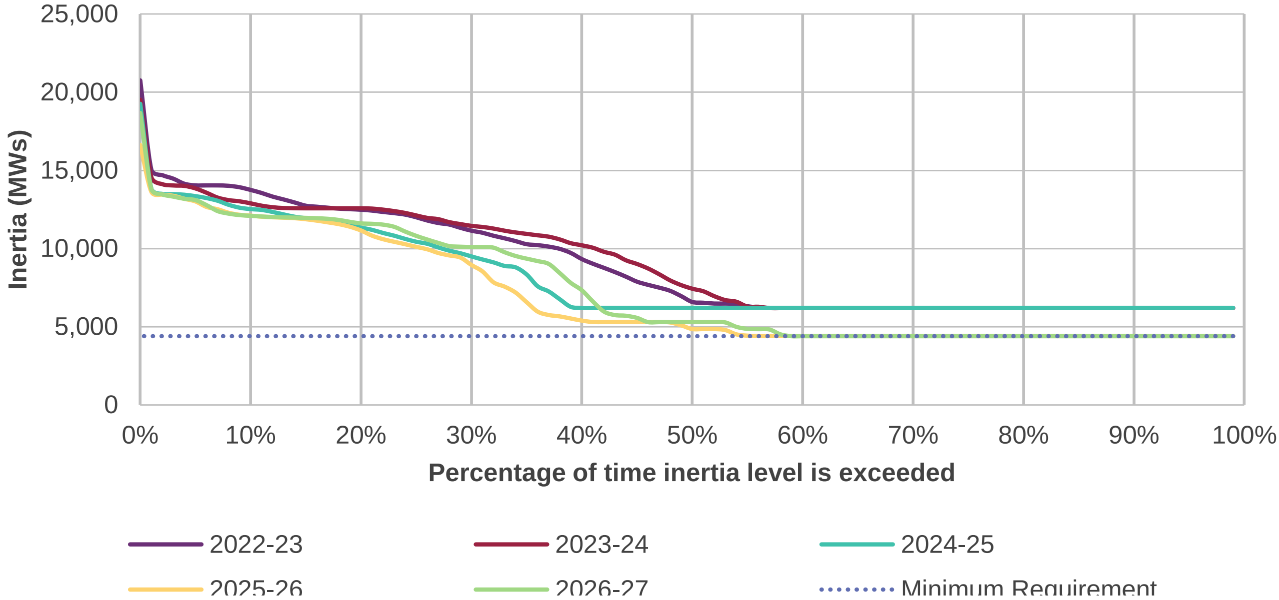
A. The figure represents the relationship between the level of inertia required against the amount of FFR required for each level of inertia.
B. Square data points show actual operating points which have been modelled and provide a secure system. A line is drawn between the operating points to broadly indicate where the system may be considered to be secure.

[23] August 2020 notice of change to South Australia inertia requirements and shortfall, and December 2020 *System Strength and Inertia Report*, both available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[24] AEMO is continuing to assess ongoing power system requirements for South Australia, including the requirement to keep two synchronous generating units online. AEMO will be providing quarterly updates on this work plan in 2022.

Inertia projections (*Step Change)*					
	2022-23	**2023-24**	**2024-25**	**2025-26**	**2026-27**
Available inertia for 99% of the time (MWs)	6,200	6,200	6,200	4,400	4,400

Figure 12 Projected inertia for the five-year outlook, *Step Change* scenario, South Australia [A]



A. Inertia projections are shown against the minimum threshold of inertia. The secure operating level of inertia is not shown as a single value because it is a function of available inertia and fast frequency response/inertia support activities.

5 Victoria

Under the *Step Change* scenario, AEMO projects significantly greater decline in synchronous generation online in Victoria and greater VRE penetration compared to the *Progressive Change* scenario.

New system strength shortfalls are declared at Hazelwood, Thomastown and Moorabool as a result of these projections. As reported in AEMO's 2020 and 2021 annual system strength assessments, system strength outcomes in Victoria are heavily influenced by reduction in the number of coal-fired generating units online, and shortfalls have previously been foreshadowed in those reports. Due to the greater decline in synchronous generation online in the *Step Change* scenario, these system strength shortfalls are now brought forward within the five-year planning horizon.

Inertia in Victoria is also expected to decline below the minimum threshold level and the secure operating level throughout the coming five-year outlook period. As islanding of Victoria from the remainder of the NEM is not considered likely, AEMO is not declaring a shortfall at present, but intends to undertake additional assessments to consider the available inertia in adjacent regions that may form a separate island within the NEM.

In its role as the jurisdictional planning body in Victoria, AEMO is working with the Victorian Government to plan for the ongoing energy transition.

This section provides:

- Supply and demand outlook (Section 5.1).
- Assessment of system strength shortfalls (Section 5.2).
- Assessment of inertia shortfalls (Section 5.3).

5.1 Supply and demand outlook

Victoria is forecast to experience a higher minimum operational demand (sent-out[25]) over the next five years under the *Step Change* scenario, compared to the *Progressive Change* scenario, as shown in Figure 13. The figure shows 90% POE and 50% POE forecasts for both scenarios[26].

Under *Step Change* there is over 550 MW more utility-scale VRE installed in Victoria compared to *Progressive Change* by 2026-27. There is also additional coal unit retirement projected, as shown in Figure 14.

[25] Refers to power provided by generating units to meet electrical demand, it does not include the power used to operate the generating unit.

[26] A 50% POE forecast is expected statistically to be met or exceeded one year in two, and is based on average weather conditions. A 90% POE forecast for minimum demand is based on more extreme conditions that could be expected one year in 10.

Figure 13 Actual minimum demand and forecast 90% POE and 50% POE minimum operational demand (sent-out) for Victoria, 2016-17 to 2026-27

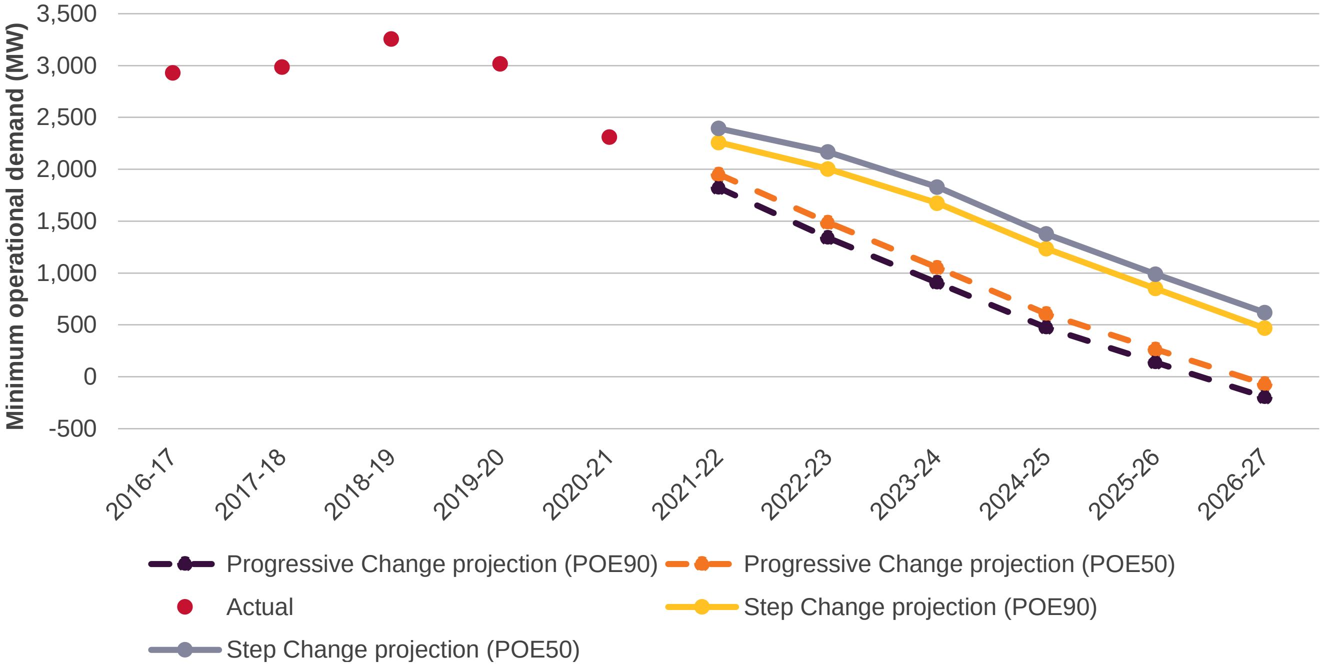
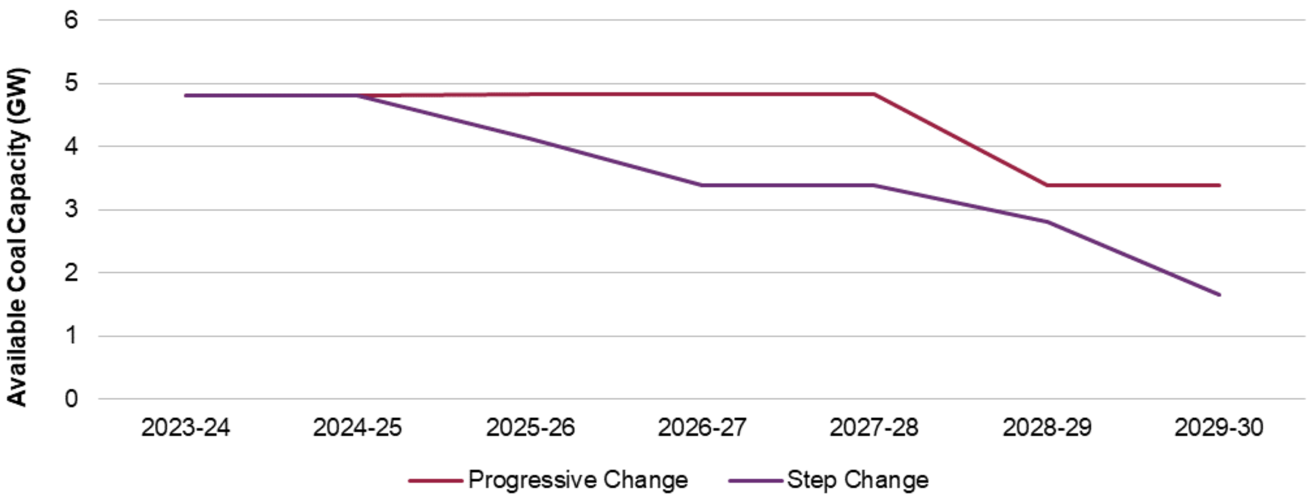


Figure 14 Projected retirement of coal units in Victoria: *Step Change* versus *Progressive Change*, 2023-24 to 2029-30



5.2 2021 System strength assessment

5.2.1 Requirements

In this update. the system strength requirements are unchanged from the original 2021 System Security Reports. See Table 5 for details.

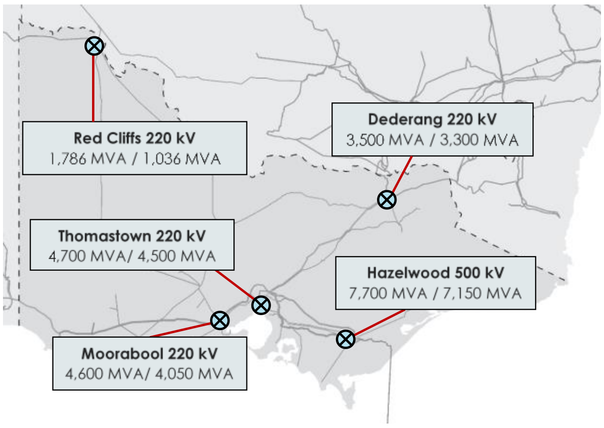
Table 5 Victoria system strength requirements

Fault level node	Fault level node class	2021 minimum three phase fault level (MVA)		Comments [A]
		Pre-contingency	Post-contingency	
Dederang 220 kV	Remote from synchronous generation	3,500	3,300	Per December 2020 determination.
Hazelwood 500 kV	Synchronous generation centre; close to Basslink DC link	7,700	7,150	Per December 2020 determination.
Moorabool 220 kV	High IBR	4,600	4,050	Per December 2020 determination.
Thomastown 220 kV	Metropolitan load centre	4,700	4,500	Per December 2020 determination.
Red Cliffs 220 kV	High IBR; Remote from synchronous generation	1,786	1,036	Per December 2021 determination.

A. 2020 *System Strength and Inertia Report*, at aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

5.2.2 Outcomes

Victoria



AEMO is declaring new system strength shortfalls at Hazelwood, Moorabool and Thomastown under the *Step Change* scenario which forecasts earlier coal generation retirements and greater VRE penetration, compared to the *Progressive Change* scenario

In its role as the jurisdictional planning body in Victoria, AEMO is working with the Victorian Government on a variety of measures to support the ongoing energy transition[27, 28].

The Victorian region analysis includes the planning assumption of the prior outage of a Hazelwood – South Morang 500 kV line during low loading conditions for voltage control. Usually, this coincides with a lower number of synchronous generators online, and as such is considered to be a realistic operating condition.

Projections (*Step Change*) and shortfalls

Node	Projected minimum three phase fault level for 99% of the time					Shortfalls and comments [A]
	2022-23	20223-24	2024-25	2025-26	2026-27	
Dederang 220 kV	3,648	3,921	3,918	3,899	3,897	No shortfall
Hazelwood 500 kV	8,691	8,696	8,652	7,824	6,947 (203 MVA shortfall)	A shortfall of 203 MVA is declared for 1 July 2026. AEMO will request that AEMO (as the Victorian system strength service provider) provide system strength services to address the shortfall by 1 July 2026. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.

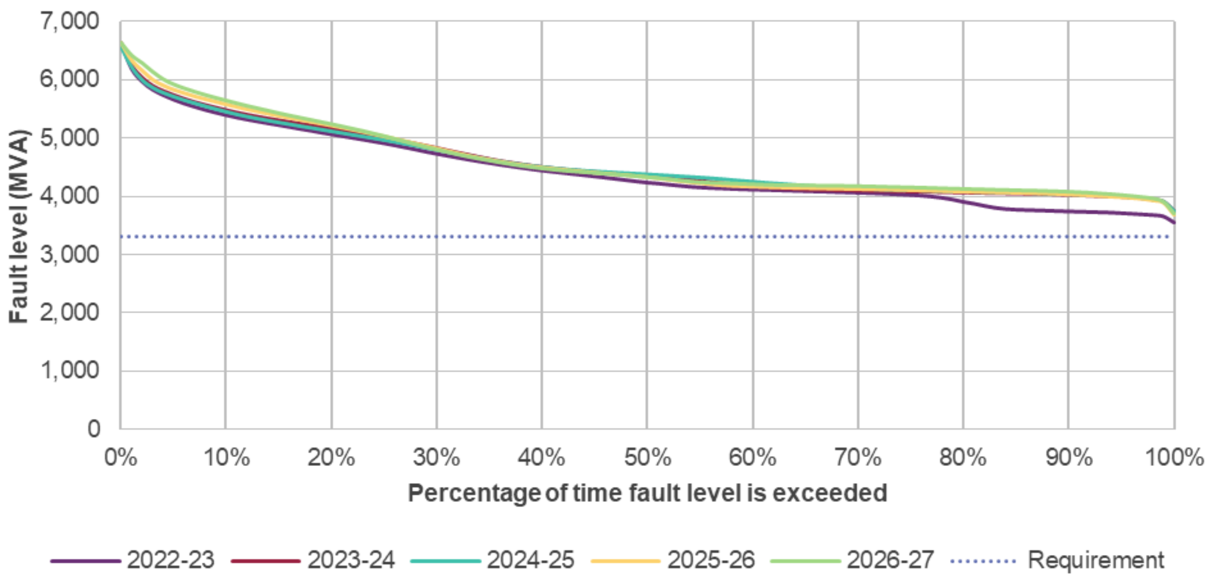
[27] AEMO, as the jurisdictional planning body in Victoria, is working with the Victorian Government to support its plans to outline network investments that enable further renewable development in Victorian renewable energy zones. By Ministerial Order under the *National Electricity (Victoria) Act* 2005 (NEVA), the Victorian Government has directed AEMO to progress procurement activities for six potential near-term projects (Stage 1). If these projects proceed, they may be considered in future system strength assessments.

[28] In March 2021, Energy Australia announced that Yallourn Power Station will retire in mid-2028, providing 7-years' notice in an agreement with the Victorian Government to ensure a smooth transition (Victorian Government, 'Statement from the Minister for Energy', 10 March 2021. Available at https://www.premier.vic.gov.au/statement-minister-energy?msclkid=399ee6e5d0d211ecb7ed0c845955e241.) The Victorian Government is also currently progressing a number of system strength projects under the Renewable Energy Zone Development Plan (Stage 1). The Victorian Government and AEMO, in its role as the jurisdictional planning body in Victoria, will continue to analyse the degree to which these arrangements will impact the declared shortfall.

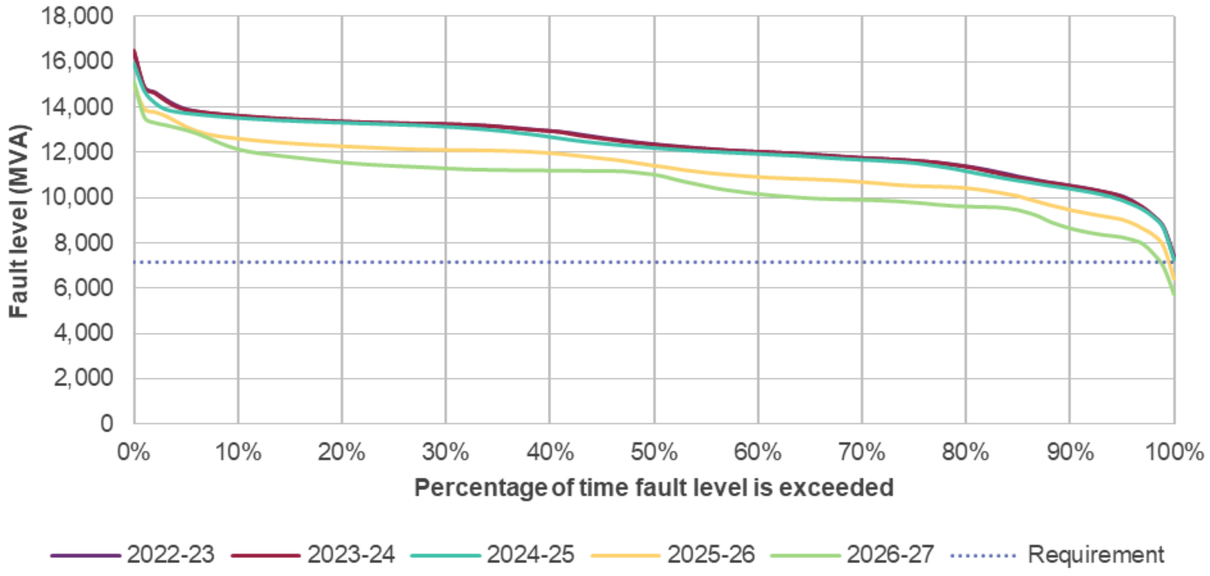
Victoria						
Moorabool 220 kV	4,482	4,498	4,387	4,247	4,019 (31 MVA shortfall)	A shortfall of 31 MVA is declared for 1 July 2026. AEMO will request that AEMO (as the Victorian system strength service provider) provide system strength services to address the shortfall by 1 July 2026. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Thomastown 220 kV	5,165	5,156	5,100	4,755	4,221 (279 MVA shortfall)	A shortfall of 279 MVA is declared for 1 July 2026. AEMO will request that AEMO (as the Victorian system strength service provider) provide system strength services to address the shortfall by 1 July 2026. AEMO acknowledges that further joint planning will be required to fix on a precise value before delivery of the services.
Red Cliffs 220 kV	1,048	1,046	1,137	1,992	2,063	No shortfall

A. The system strength outcomes for Victoria are assessed on a post-contingent basis.

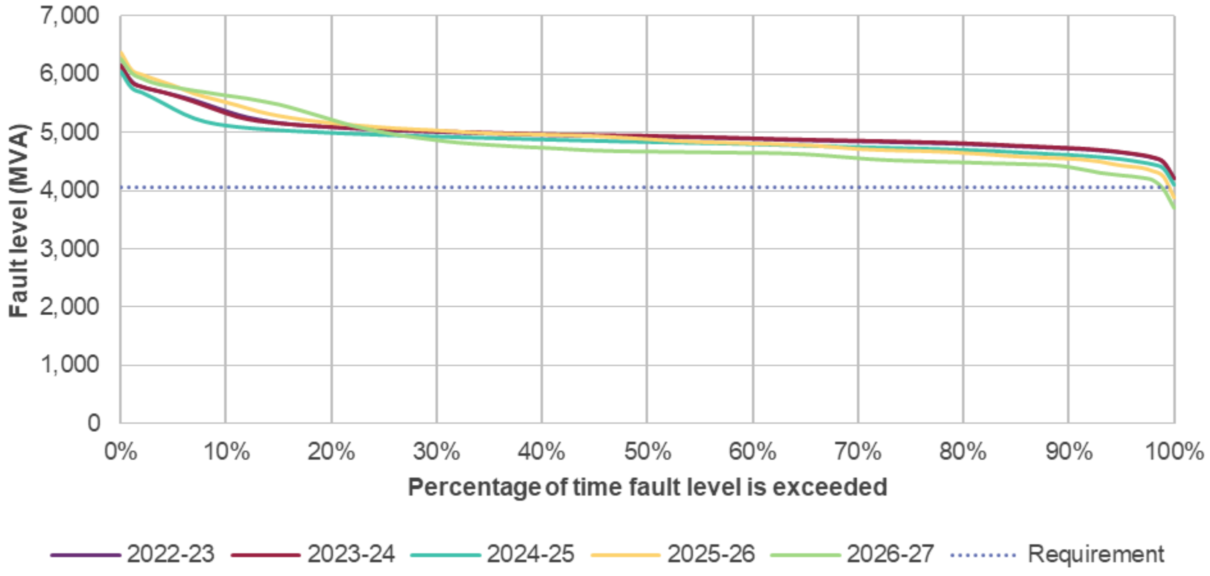
Dederang 220 kV



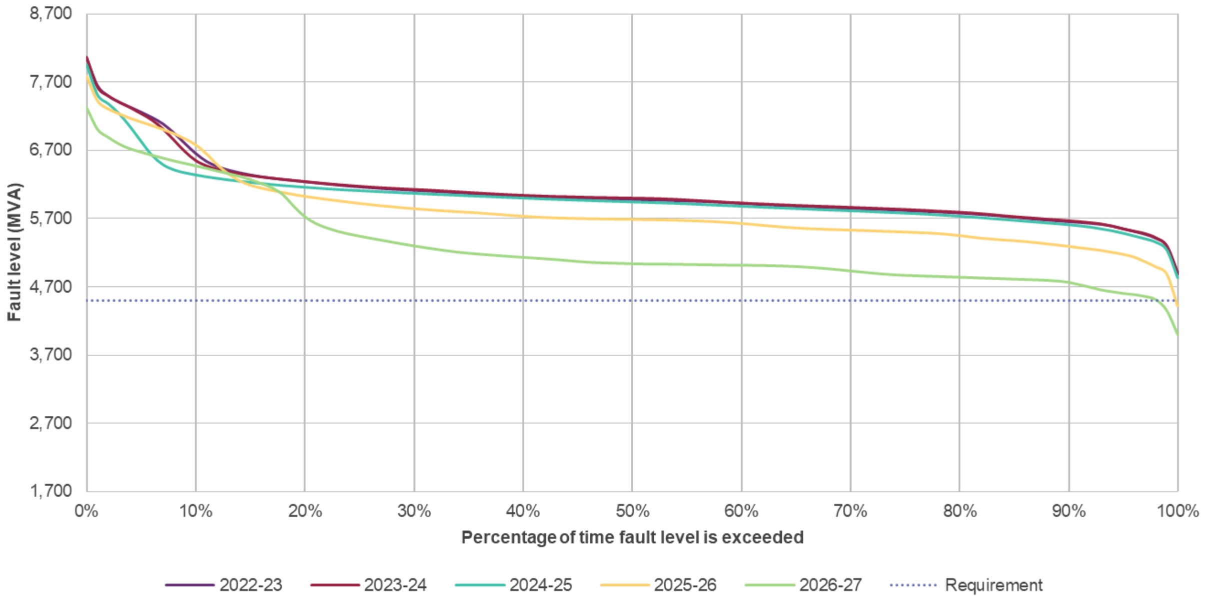
Hazelwood 500 kV



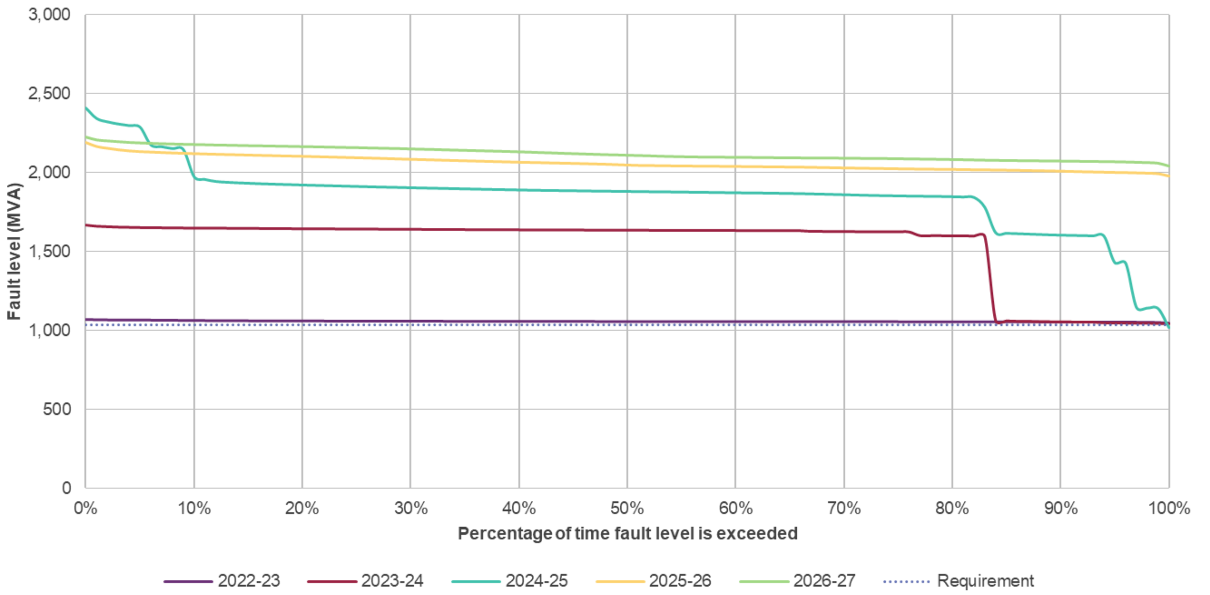
Moorabool 220 kV



Thomastown 220 kV



Red Cliffs 220 kV



* Increasing fault level projections at Red Cliffs coincide with Project EnergyConnect stage 1 and stage 2 network augmentations.

5.3 2021 Inertia assessment

Victoria

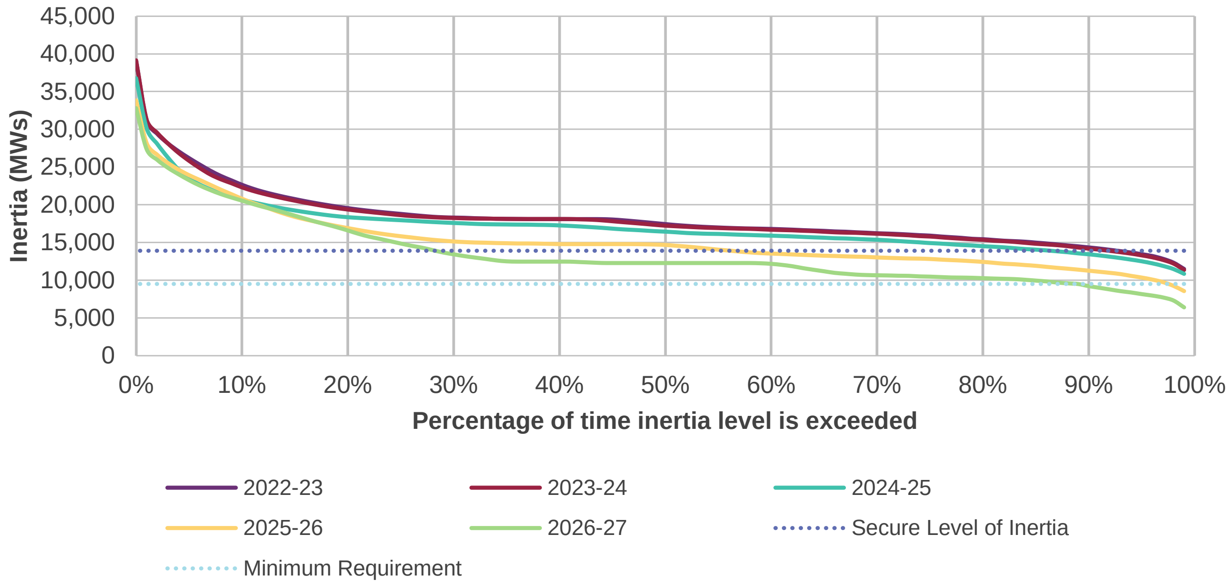
Under the *Step Change* scenario, AEMO projects that inertia in Victoria will decline below the minimum threshold level and the secure operating level throughout the coming five-year outlook period. However, as Victoria islanding from the remainder of the NEM is considered unlikely, no shortfall can be declared under the current application of the existing framework.

Future decommitment of large synchronous generators during low demand periods may cause a reduction in online inertia in the Victoria region.

Inertia requirements			
	2020	**2021**	The secure operating level and minimum operating level of inertia for Victoria are held steady at the values determined in December 2020. These have been calculated including fast frequency response capability provided by the Victorian Big Battery. Declaration of any inertia shortfall for a region must also consider the likelihood of islanding. Islanding of Victoria alone remains unlikely, consistent with AEMO's 2020 and 2018 assessments. This finding is largely driven by the diversity and number of AC interconnectors that exist between Victoria and the adjacent regions. Net distributed PV trip has not been incorporated in this assessment, and the secure operating level is not provided as a ratio of synchronous inertia and fast frequency response or Fast FCAS, because islanding is not considered likely and so a shortfall will not be declared.
Secure operating level of inertia (MWs)	13,900	13,900	
Minimum operating level of inertia (MWs)	9,500	9,500	
Net distributed PV Trip (MW)	-	-	
Risk of Islanding	Not Likely	Not Likely	

Inertia projections (*Step Change*)					
	2022-23	**2023-24**	**2024-25**	**2025-26**	**2026-27**
Available inertia for 99% of the time (MWs)	11,505	11,353	10,854	8,570	6,375

Figure 15 Projected inertia for the five-year outlook, *Step Change* scenario, Victoria



6 Next steps

In this update, AEMO has assessed a number of system strength and inertia shortfalls within the five-year outlook period. Table 6 summarises the requests to TNSPs to make system strength and inertia services available.

If you wish to provide any comments or ask any questions about this report, please contact AEMO via planning@aemo.com.au.

AEMO and the TNSPs will undertake joint planning in 2022 and beyond to ensure that essential power system needs are met as the Australian energy transformation continues at pace.

Table 6 Services to be requested from TNSPs for system strength and inertia shortfalls

Region	Requests for system strength and inertia services
New South Wales	• AEMO will request that Transgrid make system strength services available to address a shortfall at Newcastle ranging from 1,190 MVA to 1,092 MVA, from 1 July 2025 until at least 31 December 2026. • AEMO will request that Transgrid make system strength services available to address a shortfall at Sydney West ranging from 1,026 MVA to 944 MVA, from 1 July 2025 until at least 31 December 2026.
Queensland	• AEMO will request that Powerlink make system strength services available to address a shortfall at Gin Gin, ranging from 33 MVA to 90 MVA, from 31 January 2023 until at least 31 December 2026. • The inertia shortfall declared in the original 2021 *System Security Reports* is rescinded.
South Australia	• No changes from original 2021 *System Security Reports*.
Tasmania	• No changes from original 2021 *System Security Reports*.
Victoria	• AEMO will request that AEMO (as the Victorian system strength service provider) make system strength services available to address a shortfall at Hazelwood of 203 MVA, from 1 July 2026 until at least 31 December 2026. • AEMO will request that AEMO (as the Victorian system strength service provider) make system strength services available to address a shortfall at Moorabool of 31 MVA, from 1 July 2026 until at least 31 December 2026. • AEMO will request that AEMO (as the Victorian system strength service provider) make system strength services available to address a shortfall at Thomastown of 279 MVA, from 1 July 2026 until at least 31 December 2026.

A1. Generator, network and market modelling assumptions

This appendix provides the assumptions used in this report relating to generators, transmission network augmentations, and market modelling for generator dispatch.

A1.1 Generator assumptions

Committed generation projects

The system strength and inertia projections consider existing generators already in service as well as any committed and committed* scheduled and semi scheduled generation projects from the 2021 *Inputs, Assumptions and Scenarios Report* (IASR)[29].

The system strength and inertia projections also consider anticipated projects captured in the 2021 IASR, as well as any new generation projects forecast to be developed under the *Step Change* scenario prepared for the Draft 2022 ISP[30]. In addition, the most recent status for the Torrens Island battery energy storage system was included, as at February 2022.

Generation withdrawal

The system strength and inertia projections in this report are aligned with the generator withdrawals in the *Step Change* scenario of the Draft 2022 ISP. The recent announcement by Origin Energy for the potential early retirement Eraring Power Station[31] in August 2025 is also reflected in the forecasts.

A1.2 Transmission network augmentations

Table 7 provides the details and modelling date for the large committed and anticipated transmission network augmentation projects included in the system strength and inertia projections in this report. Future transmission network augmentations are not included in the minimum system strength and inertia requirements. These projects are modelled consistent with information used in the original 2021 *System Security Reports*.

Table 7 Large transmission network upgrades included in each assessment

	Augmentation detail	Modelling date (Calendar year)[A]	Included in assessment
South Australia system strength remediation	The South Australia system strength remediation project includes the installation of two high inertia synchronous condensers at Davenport 275 kV substation and two high inertia synchronous condensers at Robertstown 275 kV substation. Each of the four synchronous condensers provide 575 MVA nominal fault current and 1,100 MWs of inertia and were commissioned at the end of 2021.	In service	System strength and inertia projections

[29] Available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[30] Available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[31] See https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

	Augmentation detail	Modelling date (Calendar year)[A]	Included in assessment
QNI minor	QNI Minor is the upgrade of the existing interconnector with uprating to increase thermal capacity of the existing transmission lines and installation of additional new capacitor banks and Static Var Compensators (SVCs) to increase transient stability limits on the Queensland to New South Wales interconnector.	Early 2022[B]	System strength and inertia projections
VNI Minor	VNI Minor is an upgrade of the existing Victoria – New South Wales interconnector with the installation of an additional 500/330 kV transformer, uprating to increase thermal capacity of the existing transmission, and installation of power flow controllers in New South Wales to manage the overload of transmission lines.	2022 [C] (Victoria side) 2023 (New South Wales completion date)	System strength and inertia projections
South Australia Eyre Peninsula Link	This project will replace the existing 132 kV lines between Cultana and Port Lincoln with a new double circuit line. This includes a new double circuit line from Cultana to Yadnarie built at 275 kV but energised at 132 kV and a new double circuit 132 kV line from Yadnarie to Port Lincoln.	2022	System strength and inertia projections
Powering Sydney's future	This project is to install a new 330 kV cable between Beaconsfield and Rookwood substations. Derate the existing 330 kV cable and service reactor between Beaconsfield and Sydney South from 300 kV to 132 kV.	Fully completed in 2022	System strength and inertia projections
Western Victoria transmission network	The Western Victoria transmission network project is split into two stages. Parts of stage 1 are already complete. Remainder of Stage 1: • Uprate Bendigo – Kerang 220 kV line and Kerang- Wemen – Red Cliffs 220 kV lines Stage 2: • A new substation north of Ballarat • Cut-in the Ballarat-Bendigo 220 kV line at new substation North of Ballarat • A new 220 kV double-circuit transmission line from substation north of Ballarat to Bulgana (via Waubra) • Moving the Waubra Terminal Station connection from the existing Ballarat–Ararat 220 kV line to a new 220 kV line connecting the substation north of Ballarat to Bulgana • Cut-in the existing Ballarat-Moorabool No.2 220 kV line at Elaine Terminal Station. • A new 500 kV double-circuit transmission line from Sydenham to the new substation north of Ballarat • 2 x 500/220 kV transformers at the new substation north of Ballarat • 4 x 50 MVAr 500 kV reactors, one at each end of the new 500 kV lines.	Late 2021 (Stage 1) 2025 (Stage 2)	System strength and inertia projections
Project EnergyConnect[D]	Stage 1: • A new Robertstown to Bundey 275 kV double-circuit line strung one circuit initially. • A new Bundey to Buronga 330 kV double-circuit line strung one circuit initially. • A new Buronga to Red Cliffs 220 kV double-circuit line strung one circuit only. • A new 330/275 kV substation and a 330/275 kV transformer at Bundey. • A new 330/220 kV substation, a 330/220 kV transformer and a 330 kV phase shifting transformer at Buronga. • Static and dynamic reactive plant at Bundey and Buronga. Stage 2: • Second 275 kV circuit strung on the Robertstown–Bundey 275 kV double-circuit line. • Second 330 kV circuit strung on the Bundey–Buronga 330 kV double-circuit line.	Stage 1 2023 Stage 2 2024[C]	System strength and inertia projections

	Augmentation detail	Modelling date (Calendar year)[A]	Included in assessment
	• A new 330 kV double-circuit line from Buronga to Dinawan. • A new 500 kV double-circuit line from Dinawan to Wagga Wagga operating initially at 330 kV. • Two additional new 330/275 kV transformers at Bundey. • A new 330 kV switching station at Dinawan. • Additional new 330 kV phase shifting transformers at Buronga. • Additional new 330/220 kV transformer at Buronga. • Turning the existing 275 kV line between Para and Robertstown into Tungkillo. • Static and dynamic reactive plant at Bundey, Robertstown, Buronga and Dinawan. • A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia.		
Central-West Orana renewable energy zone (REZ) Transmission Link[E]	The Central West Orana REZ link includes extension of the 500 kV and 330 kV network in the Central-West Orana region of New South Wales.	2024[D]	System strength and inertia projections [D]

G. Modelling dates are consistent with those applied in the original 2021 *System Security Reports*. For some of the nearer-term projects, AEMO is aware of some delays to delivery and commissioning. However, in these cases AEMO does not consider the delays to be impactful for the purposes of system strength and inertia assessments and so the modelling dates are unchanged.
H. The date captured in the table for QNI minor is the expected in-service date. AEMO, consistent with the ESOO and the 2021 IASR, assumed the full capacity available from 1 July 2022 to allow time for inter-network testing.
I. The date captured in the table for VNI minor is the expected in-service date. AEMO, consistent with the ESOO and the 2021 IASR, assumed the full capacity available from September 2023 to allow time for inter-network testing.
J. The date captured in the table for Project EnergyConnect is the expected in-service date. AEMO, consistent with the ESOO and the 2021 IASR, assumed the full capacity available from July 2025 to allow time for testing.
K. Central West Orana is modelled for the system strength and inertia projections. AEMO did not assess this for NSCAS, as generation projects connecting with the project will assist with management of voltages. Since voltages issues are localised, generation locations are pertinent to this analysis. AEMO will revisit this in the NSCAS assessment next year.

A1.3 Market modelling of generator dispatch

AEMO undertakes integrated energy market modelling to forecast future investment in and operation of electricity generation, storage and transmission in the NEM[32].

Projected generation dispatch from the *Step Change* scenario results for the Draft 2022 ISP have been used for this report. These market modelling results:

- Cover the five financial years from 2022-23 to 2026-27.
- Are based on the *Step Change* scenario generator and transmission build outcomes for the Draft 2022 ISP. It should be noted that the *Step Change* outcomes used in the Final 2022 ISP may vary.
- Generator dispatch projections are from a time-sequential model using the 'bidding behaviour model' for realistic generator dispatch results given the generation and build outcomes. The bidding behaviour model uses historical analysis of actual generator bidding data and back-cast approaches for the purposes of calibrating projected dispatch[33].
- Apply the *Step Change* scenario 50POE demand projection from the Draft 2022 ISP.

[32] AEMO. 2021 ISP Methodology. Available at https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en.

[33] Details for the bidding behaviour model are provided in AEMO's 2021 ISP Methodology. Available at https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en.

- Apply projections of generation outages based on Monte Carlo simulation.
- Apply projections of planned maintenance. Maintenance events are assumed to be distributed throughout the year such that they do not limit generating capacity at times when it is most required. Over time, as synchronous generation declines, this may be an optimistic assumption.
- This update to the *Step Change* scenario is based on a much wider range of market modelling iterations for each year of the study period, capturing multiple reference years and generator outage and maintenance patterns. This better captures the variability in weather patterns and generator outage and maintenance patterns, and hence gives better regard of typical dispatch patterns as per 5.20B.3 of the NER.
- Consider potential for additional coal seasonal decommitments, informed by forecast wholesale prices.

When applying the market modelling results to assess the system strength and inertia projections, some post-model adjustments are made where necessary based on industry knowledge and known operational practices.

A2. EMT studies for system strength

This appendix notes details for the EMT studies undertaken for the minimum fault level requirements included in this report, consistent with the System Strength Requirements Methodology[34].

The following sections provide details on treatment of minimum synchronous machine dispatch combinations, contingencies considered, success criteria, and model setup for the assessment undertaken to update the requirements at Red Cliffs.

Minimum synchronous machine dispatch combinations

AEMO uses minimum synchronous machine dispatch combinations to derive the minimum fault level requirements for each region. These combinations are verified using EMT analysis to ensure that power system stability and system standard criteria are met. Table 8 provides the public references available for existing combinations.

Table 8 References for minimum synchronous machine dispatch combinations

Region	Reports	Reference
Queensland	Appendix 3 of the *2020 System Strength and Inertia Report* A sub-set particularly relevant for North Queensland are listed in *Transfer Limit Advice – System Strength NQLD v8*	AEMO Planning for operability, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability AEMO Limits advice, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice
New South Wales	Appendix 3 of the *2020 System Strength and Inertia Report*	AEMO Planning for operability, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability
Victoria	Appendix 3 of the *2020 System Strength and Inertia Report* Further details in *Transfer Limit Advice – System Strength VIC and SA v40*	AEMO Planning for operability, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability AEMO Limits advice, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice
South Australia	Appendix 3 of the *2020 System Strength and Inertia Report* Further details in *Transfer Limit Advice – System Strength VIC and SA v40*	AEMO Planning for operability, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability AEMO Limits advice, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice
Tasmania	Appendix 3 of the *2020 System Strength and Inertia Report*	AEMO Planning for operability, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability

Contingencies

AEMO calculates the minimum three phase fault levels for system intact conditions (pre-contingency) to represent the normal operating conditions secure level of system strength required to be available, as well as the

[34] AEMO. *System Strength Requirements Methodology.* July 2018. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

post-contingency value in most cases[35]. The credible contingencies considered to calculate these values represent single power system element outage resulting in the highest fault level reduction at each fault level node, and are provided in Table 9.

Table 9 Contingencies considered to calculate minimum three phase fault levels requirements at fault level nodes

Region	Fault level node	Contingency considered
New South Wales	Armidale 330 kV	Tamworth – Armidale 330 kV line
	Darlington Point 330 kV	Wagga – Darlington Point 330 kV line
	Newcastle 330 kV	Liddell – Newcastle 330 kV line
	Sydney West 330 kV	Sydney West – Sydney North 330 kV line
	Wellington 330 kV	Wollar – Wellington 330 kV line
Queensland	Gin Gin 275 kV	Woolooga – Gin Gin – Calliope River 275 kV line
	Greenbank 275 kV	One Millmerran Power Station unit
	Lilyvale 132 kV	Lilyvale – Broadsound 275 kV line
	Ross 275 kV	• Ross – Strathmore 275 kV line • Townsville Power Station 132 kV feeder (if Townsville Power Station is in service) • Mt Stuart Power Station 132 kV feeder (if Mt Stuart Power Station is in service)
	Western Downs 275 kV	Braemar 275/330 kV transformer
South Australia	Davenport 275 kV	One synchronous condenser at Davenport
	Para 275 kV	One synchronous condenser at Robertstown
	Robertstown 275 kV	One synchronous condenser at Robertstown
Tasmania[A]	Burnie 110 kV	Burnie 220 kV – Sheffield 220 kV line
	George Town 220 kV	N/A
	Risdon 110 kV	N/A
	Waddamana 220kV	N/A
Victoria[B, C]	Dederang 220 kV	South-Morang Transformer 500 / 330 kV
	Hazelwood 500 kV	Hazelwood – South Morang 500 kV line
	Moorabool 220 kV	Transformer 500 / 220 kV
	Red Cliffs 220 kV	Red Cliff – Wemen 220 kV line
	Thomastown 220 kV	Thomastown (Bus B) – Keilor 220 kV line

A. AEMO and TasNetworks use pre-contingency values to inform the operational arrangements for system strength requirements in Tasmania. These nodes have specific local requirements which must be met for the pre-contingent levels, namely requirements to do with maintaining Basslink requirements, switching requirements for local reactive plant, and some power quality requirements for metropolitan load centres.
B. One of two 500 kV transmission circuits in Victoria (Hazelwood – South Morang 500 kV line 1 or Hazelwood – Rowville 500 kV line 3) are assumed to be out of service during system strength studies, as these circuits may be switched off during low loading conditions for voltage control.
C. A range of contingencies were assessed to revise the Red Cliffs 220 kV minimum fault level requirements in this report, as noted in the Red Cliffs model setup section below.

Success criteria

The criteria used to assess system strength outcomes through EMT studies are outlined below.

- Generators, as well as relevant regional interconnectors, remain online.

[35] The post-contingency level (associated with a given pre-contingency level) is associated with the network landing in a satisfactory state following the occurrence of any credible contingency. These are not secure fault level requirements for prior or planned network outage condition.

- All online generators return to steady-state conditions following fault clearance, unless they are intentionally tripped as a part of the contingency.
- The power system frequency is restored to within the normal operating frequency band (49.85-50.15 hertz [Hz]).
- The transmission network voltage profiles across the region return to an acceptable range.
- Post fault voltage oscillations are adequately damped. At present, AEMO assesses whether the sub-synchronous peak-to-peak voltage oscillation magnitude is below an upper limit of 0.3% at 8-10 Hz. Increasingly AEMO is applying a stricter limit and in future expects to move the limit as low as is possible while also allowing for the limitations of modelling methods.

EMT model setup – Red Cliffs

In this report, AEMO declares an update to the pre- and post-contingency minimum fault level requirements at the Red Cliffs 275 kV node. The contingencies tested for this assessment were:

- Red Cliffs – Kiamal: Two phase to ground fault (2ph-G) and disconnection of Red Cliffs – Kiamal line.
- Red Cliffs – Buronga: Two phase to ground fault (2ph-G) and disconnection of Red Cliffs – Buronga line.
- Ballarat – Waubra – Ararat: Two phase to ground fault (2ph-G) and disconnection of Ballarat – Waubra – Ararat line.
- Kerang – Bendigo: Two phase to ground fault (2ph-G) and disconnection of Kerang – Bendigo line.
- Darlington Point – Wagga: Two phase to ground fault (2ph-G).
- Balranald – Darlington Point: Two phase to ground fault (2ph-G) and disconnection of Balranald – Darlington Point line.
- Darlington Point Synchronous Condenser: 2ph-G fault on the HV transformer terminals and disconnection of Darlington Point synchronous condenser at Buronga and inter-trip of Darlington Point Solar Farm.
- Finley Synchronous Condenser: 2ph-G fault on the HV transformer terminals and disconnection of Finley synchronous condenser at Buronga as well as an inter-trip of Finley Solar Farm

All inter-trips, runback schemes and special protection schemes relevant for the contingencies above were also included in the assessment.

The updated fault level requirement includes a minor increase due largely to the inclusion of local synchronous condensers in the calculations – both those engaged for system strength services and others associated only with system strength remediation schemes for individual solar farms. Fault level projections used to assess system strength shortfalls are adjusted accordingly to ensure that a shortfall is not declared to cover system strength remediation which is already being addressed by a responsible generator. The requirements applied in the control room may vary depending on operating conditions, for times when some generators are not online.

A3. EMT studies for inertia

This appendix notes details for the assessment method for electromagnetic transient (EMT) studies undertaken for the inertia requirements determined in this report.

Overarching assessment method

AEMO conducts EMT studies to determine the minimum threshold level of inertia and secure operating level of inertia required for each inertia sub-network in the NEM. These studies are undertaken consistent with the Inertia Requirements Methodology[36]. To calculate inertia requirements for a region, it is assumed that a region is an electrical island and all necessary services must be sourced from within the region.

For this report, the secure operating levels of inertia for Queensland and South Australia have been assessed in accordance with the assessment method described in this section. The minimum threshold levels of inertia for those regions, as well as all requirements for all other regions, remain at the levels set in previous AEMO publications.

This section notes the treatment of assumptions, contingencies, size of distributed PV disconnection, treatment of primary frequency response requirements and success criteria for the studies.

Assumptions

Assumptions for the EMT model for inertia requirements studies include:

- Committed, committed*, commissioned generation as per the 2021 IASR[37]. On a case-by-case basis, some committed or existing utility-scale battery systems and synchronous condensers are included in the requirements studies, but only where they are considered to be part of the typical dispatch being considered for that study.
- Output from online generators can be reduced to limit the size of the contingency. However, this reduction should not compromise the lower frequency control capability of the generator. The generator should have sufficient foot room to reduce their generation in response to high frequency events.
- Registered frequency control ancillary services (FCAS) for large generators and loads is modelled in accordance with their individual registrations[38] as at August 2021. When a generator is online, it must provide at least its registered FCAS[39].
- Disconnection of distributed photovoltaics (PV) as a result of a nearby disturbance is modelled as an increase in the size of the contingency. In this report, 'distributed PV' refers to PV generation connected to the distribution network that is either estimated by the Australian Solar Energy Forecasting System (ASEFS2)[40] (smaller than 100 kilowatts [kW]) or is non-scheduled PV generation smaller than 30 MW.

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[36] Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[37] Available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[38] AEMO. NEM Registration and Exemption List. Accessed December 2021. Available at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration.

[39] It should be noted that registered FCAS is for 0.5 Hz arresting band while island arresting band is 1 Hz.

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

- The amount of distributed PV and load disconnection used in the analysis in this report was determined through dynamic load flow studies using PSS®E, not through EMT studies. The disconnection in response to a nearby contingency event was estimated as a percentage of the total distributed PV and underlying load in the region, and that percentage was then applied to the latest demand and PV projections used in the *Progressive Change* scenario. More details are provided in a dedicated section below.
- The frequency dead bands for generators and utility-scale battery systems are set consistent with the latest adjustments declared by affected generators to comply with the primary frequency response (PFR) requirements. More details are provided in a dedicated section below.

Contingencies

The secure operating level of inertia is assessed by considering the minimum synchronous machine dispatch combinations that provide sufficient frequency control and inertia within a region, including ensuring that the system remains in a satisfactory operating state following a credible contingency. Several contingencies are studied, with the secure operating level determined based on the worst-case contingency identified through the EMT analysis.

In recent years AEMO has considered the credible contingencies which must be assessed to understand frequency disturbances and inertia requirements within an islanded system to be as follows:

- Loss of an online generator, plus the coincident unintended disconnection of distributed PV[41].
  - Although the amount of generation from an online generator may be able to be reduced to lower the contingency size when the region is islanded (subject to other system conditions), reduction below a certain level for thermal plant is not possible due to minimum stable operating point requirements.
  - The size of distributed PV disconnection would be largely uncontrolled and would depend on factors such as the amount of distributed PV generation at the time as well as proximity to the initiating generator contingency. The largest net loss of distributed PV has been applied to a subset of the credible contingency events studied for each region as not all contingency events will result in a severe enough voltage depression to trip off distributed PV.
- Loss of the largest transmission-connected load which can be considered as a credible loss (in some cases, this means a subset of the overall site load).

Size of distributed PV disconnection

To estimate the net impact of a distributed PV disconnection, the demand modelled for the region is scaled up to reflect the estimated additional demand on the system after the distributed PV is disconnected. This value is only included in the modelled credible contingency if it is a daytime contingency event, and if that contingency event would create a sufficient voltage depression to initiate distributed PV disconnection.

The most onerous distributed PV disconnection in South Australia occurs for the trip of a Torrens Island B Power Station unit, due to the short electrical distance between the Torrens Island generating system and the Adelaide metropolitan area, where much of the distributed PV is installed. For Queensland, the most onerous distributed

[41] Distributed PV refers to PV that meets AEMO's Australian Solar Energy Forecasting System[41] (ASEFS2) total installed capacity, which only includes capacities less than 100kW. AEMO, ASEFS2. See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system.

PV disconnection occurs for the trip of a Tarong Power Station unit, due to the short electrical distance between the Tarong generating system and the Brisbane metropolitan area where much of the distributed PV is installed.

To calculate the distributed PV disconnection and underlying load sizes used for this report, AEMO applied the Central disconnection factors documented in the 2020 ESOO[42] to the latest *Progressive Change* forecast. The net distributed PV disconnection sizes were forecasted for each half hourly interval and the largest disconnection size was applied to the relevant generator contingency. The equation for disconnection of net distributed PV is given here:

$$Disconnection(MW) = PV_{disc\%} * PV_{Total} - Load_{disc\%}[OPSOPVLITE + AUX]$$

where:

$PV_{disc\%}$	is the distributed PV disconnection factor from the 2020 ESOO
PV_{Total}	is the distributed PV generating at the time in the region (total distributed PV installed * capacity factor[43])
$Load_{disc\%}$	is the load disconnection factor from the 2020 ESOO
OPSOPVLITE	is the underlying load in the region (Operational as sent out (OPSO) + PV generated at the time)
AUX	is the generator auxiliary load in the region at the time

For this analysis, beyond 2021-22, it has been assumed that net disconnection will not increase, as distributed PV units installed after the end of 2021 were expected to have improved disturbance ride-through capabilities from the updated AS/NZS 4777.2:2020 standard[44]. This assumption will be revisited in future inertia requirement assessments, because preliminary analysis indicates that approximately 80% of distributed inverters installed during January to March 2022 are not compliant with the new standard, with most non-compliant inverters continuing to be installed under the older 2015 standard with poor disturbance ride-through capabilities. This means contingency sizes related to distributed PV will in fact continue to increase until compliance rates are significantly improved.

Primary frequency response requirements

The continuous PFR of generators can be used to maintain an aggregate level of responsiveness in the power system to relatively small and ongoing, incremental changes in frequency.

In March 2020, the Australian Energy Market Commission (AEMC) introduced mandatory PFR requirements for scheduled and semi-scheduled generators. This was specified as an interim arrangement to begin in June 2020 and sunset in June 2023 to allow for further work to be done to understand power system requirements and consider enduring PFR arrangements. In September 2021, the AEMC released a draft rule determination for

[42] AEMO, 2020 ESOO, Appendix A5.1, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en. AEMO will seek to update these figures when possible.

[43] The maximum capacity factor typically applied (based on historical observations) is 70%.

[44] AEMO. AS/NZS 4777.2 – Inverter Requirements Standard. Available at https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/as-nzs-4777-2-inverter-requirements-standard.

these interim PFR requirements to continue beyond the June 2023 sunset date. At the time of this update, a final determination on this rule change is expected in July 2022[45].

AEMO is coordinating changes to generator control systems in accordance with the mandatory PFR rule. The rollout of these arrangements began in late September 2020 and has taken place in tranches, starting with the largest generators (maximum capacity greater than 200 MW). Rollout is continuing, particularly for semi-scheduled generation.

Under these mandatory PFR arrangements, generators have been progressively implementing changes[46] to their control systems, as specified in AEMO's interim PFR requirements[47], to:

- Provide an automatic, locally detected active power response to changes in frequency outside a narrow frequency deadband.
- Disable any control features that act to suppress a unit's active power response to a frequency disturbance, within the plant's stable operating range.

For the purposes of the EMT studies performed to assess inertia requirements for this report, generators are assumed to comply with their mandatory primary frequency response requirements[48].

Success criteria

The success criteria for determining if an islanded region returns to a satisfactory operating state[49] following a credible contingency include:

- Frequency is maintained within the arresting frequency bands for each specific operating condition studied[50]. Consistent with good engineering practice, an operating margin of 0.1 Hz has been considered while determining the requirements. As an example, arresting frequency above 49.1 Hz is considered even though the floor of the operational frequency tolerance band is 49.0 Hz[51].
- The occurrence of a credible contingency should not result in the activation of automatic load or generation shedding schemes and consequent load or generation loss.
- The high voltage transmission network voltages across the region return to nominal voltages[52].
- All online generators return to steady-state conditions following fault clearance, unless they are intentionally tripped as part of the contingency.
- All online generations remain connected and return to new steady-state conditions, except those who are part of the contingency considered or included in any special control or protection scheme.

[45] AEMC. Primary frequency response incentive arrangements consultation webpage. Available at https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

[46] Updates on the rollout of the mandatory PFR rule are available at AEMO's Primary Frequency Response webpage at https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response.

[47] AEMO. Interim Primary Frequency Response Requirements. June 2020. Available at https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf.

[48] Application of these requirements in the EMT studies reflects the fact that the mandatory PFR requirements do not guarantee generator headroom. As such, in the EMT studies, inverter-based resources are not assumed to hold headroom or to provide raise response.

[49] Clause 4.2.2 of the NER.

[50] For the purposes of this work only the arresting band is considered which is in line with the 2018 Inertia Requirements Methodology. The arresting bands are provided in the Frequency Operating Standards, available through the AEMC website at https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

[51] As per Table A.1: Frequency bands in the Frequency operating standard - effective 1 January 2020, available through the AEMC website at https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

[52] Criteria for voltage is up to 10% higher or lower than nominal voltage.