2020 System Strength and Inertia Report

December 2020

A report for the National Electricity Market

Important notice

PURPOSE

AEMO publishes the System Strength Report and Inertia Report under National Electricity Rules clauses 5.20.7 and 5.20.5. This publication has been prepared by AEMO using information available at December 2020. Information made available after this date may have been included in this publication where practical.

DISCLAIMER

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VERSION CONTROL

Version	Release date	Changes
1.0	17/12/2020	Nil

Executive summary

AEMO has assessed the outlook for system strength and inertia in the National Electricity Market (NEM) over the coming decade. It is increasingly clear that the changing generation mix and lowering minimum demand projections will drive the need for additional system strength and inertia services, and the electricity sector will need to continue to innovate and adapt to maintain secure and efficient operation of the future power system.

System strength and inertia are critical requirements for a secure power system. A minimum level of system strength is required for the power system to remain stable, particularly for stability of the voltage waveform. Inertia in conjunction with frequency control services are needed for maintaining the power system frequency within limits.

In this inaugural 2020 System Strength and Inertia Report, AEMO observes increasing indications that, in the near future, projected system strength may be insufficient in Queensland, New South Wales, and Victoria, if certain conditions eventuate. Similarly, projected inertia may be insufficient in Queensland.

Although for a 'traditional operations' projection these outcomes are not considered likely to occur within the planning horizon of five years, there is a strong risk this could occur earlier under a high renewable energy projection, both with and without considering the potential for flexible operation of synchronous generating units. This report also:

- Updates the minimum system strength and inertia requirements across the NEM.
- Declares the re-emergence of a system strength and inertia shortfall in Tasmania in 2024 (as well as a risk of larger, earlier shortfalls in Tasmania than previously declared).
- Extends an existing inertia shortfall in South Australia by one year.
- Notes that further analysis is required to confirm the scale of the Red Cliffs system strength shortfall in Victoria beyond 2022.

AEMO welcomes feedback on the material provided in this report, and any related matters, no later than two months from the date of publication.

Feedback should be provided to planning@aemo.com.au.

Planning for the evolution of how future system security services will be sourced in the NEM

The power system was planned and designed around large thermal and hydro synchronous generation. Most of the power system design has historically been centred around the characteristics of a system dominated by these power stations, and as such they are currently relied upon for provision of a range of system services needed to keep the system secure. These power stations were located near their energy sources, which is different to where newer renewable generators are locating. This means the efficient redesign of the power system of the future will likely require provision of system services in new locations.

Commissioning of new utility-scale generation resources continues at a high pace; 4,074 megawatts (MW) of new inverter-based renewable energy generation is at the committed (final) phase of development as at November 2020[1], an increase of 1,138 MW since July 2020.

[1] Solar, wind, battery storage and other, as reported on AEMO's Generation Information page, November update, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

At the same time, due to increases in installations of distributed photovoltaic (PV) generation, AEMO has observed record minimum demand in several regions of the NEM, with South Australia experiencing a minimum demand of 270 MW (operational demand, sent out) on 7 November 2020, Victoria experiencing a minimum operational demand of 3,073 MW on 6 September 2020, and Queensland experiencing a minimum operational demand of 3,712 MW on 27 September 2020.

These trends have significant implications for the future operation of synchronous generation units. AEMO and transmission network services providers (TNSPs) need to re-engineer the power system and seek new opportunities for system service provision to ensure system security as the electricity system transitions. In addition, the Energy Security Board (ESB) and the Australian Energy Market Commission (AEMC) are progressing major regulatory reforms which will affect future provision of system strength and inertia – the post-2025 NEM market design project, and the consideration of seven National Electricity Rules (NER) rule change requests relating to the provision of system services.

AEMO is currently preparing an Engineering Framework intended to help stakeholders stay informed of the changing technical needs of the power system[2]. When planning for the provision of new system strength and inertia, AEMO and TNSPs must also account for other system needs, including thermal network capacity, stability of DER, and voltage requirements. There will be increasing opportunities for sourcing these services from non-energy providers, which may provide further efficiencies in the future power system design.

AEMO looks forward to working with TNSPs and the broader industry as work progresses on assessment of the power system, and system strength and inertia in particular.

Potential for shortfalls depending on minimum demand and synchronous generator behaviour

Record minimum demands in the NEM due to the uptake of distributed PV generation, and the high pace of commissioning of utility-scale variable renewable energy (VRE) resources, are projected to continue. There is growing evidence that these factors will result in changes to the operation of existing large synchronous generating units, including decommitment[3], and where feasible, more flexible operations. Recently announced energy infrastructure policies are intended to support increasing introduction of new renewable generation, which when realised should accelerate changes in the operation of existing thermal generation, as more renewable energy replaces energy previously produced by fossil fuel generation.

As noted above, currently the power system relies on existing large synchronous generating units to provide the bulk of the essential power system security services. Without advance market signals to incentivise these generators to remain online, or support investment in alternative sources of system security services, this decommitment could have consequential impacts on power system security services – namely system strength during normal operating conditions, and inertia requirements when a region is islanded (or at risk of islanding). Depending on the timing, number and location of these decommitments, AEMO may be required to declare shortfalls in system strength for fault level nodes in central New South Wales, central and northern Queensland, and central Victoria. An inertia shortfall for the Queensland region may also arise due to these same decommitments.

AEMO has not declared these shortfalls in this report, due to remaining uncertainty about when and to what degree existing synchronous generating units may change their operations. However, AEMO notes that the levels of system strength or inertia (as relevant) are projected to be near minimum limits, and evidence is increasingly emerging that the conditions for declaring shortfalls could arise in the near future.

AEMO will continue to monitor evolving conditions and review the assessments. Should there be evidence of acceleration of the projected reduction of synchronous generation units online, AEMO will update this notice and may declare shortfalls. AEMO considers it prudent to prepare analysis for when any resultant shortfalls are declared. AEMO will consider new information as it becomes available and provide updates as necessary. This may include publishing shortfalls ahead of the 2021 System Strength and Inertia Report/s.

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

[3] Decommitment in this report is used in the context of machines not being available, which may include withdrawal of a machine from dispatch for commercial or other reasons

Assessment of minimum system strength and inertia requirements in the NEM and update on previously declared system strength and inertia shortfalls

In this report, AEMO updates the system strength and inertia requirements for the NEM. The system strength requirements cover minimum three phase fault levels at each fault level node. The inertia requirements include the minimum threshold level of inertia for when a region is either islanded from the rest of the NEM or at credible risk of separation, and the secure operating level of inertia for when a region is islanded.

In addition, AEMO is declaring a number of extended or amended shortfalls across the NEM.

- TasNetworks has procured system strength and inertia services to address the previously declared shortfalls in **Tasmania**. Updated projections are highlighting the risk of larger shortfalls than previously declared, and AEMO will work with TasNetworks in early 2021 to review the potential drivers for these larger shortfalls as well as assess impacts on the services previously procured. Any new declaration will be made by the end of March 2021. AEMO is now also re-declaring system strength and inertia shortfalls for the period after the current contracts expire in 2024.
- The synchronous condensers being installed in **South Australia** will close the system strength and minimum inertia threshold shortfalls declared in South Australia in 2017. Procurement by ElectraNet of fast frequency response (FFR) to meet the secure level of inertia shortfall declared in August 2020 for 2021-22 is progressing, and AEMO is now declaring a new extension of that shortfall for 2022-23.
- The system strength shortfall identified at Red Cliffs in **Victoria** in 2019, and revised in 2020, has been met with system strength services procured in the local area by AEMO in its role as System Strength Service Provider for Victoria. Analysis is underway to confirm the scale of the system strength shortfall at Red Cliffs beyond 2022.
- Powerlink has proposed closing the system strength shortfall at Ross in **Queensland** by reducing the system strength requirements with inverter re-tuning of nearby generation. Studies are ongoing to confirm all requirements are met with this solution, and Powerlink is required to address the shortfall by August 2021.

Table 1 Summary of system strength and inertia outcomes for 2020

	Currently		2025	
	System strength	**Inertia**	**System strength**	**Inertia**
New South Wales			Potential for shortfalls at Newcastle and Sydney West	
Queensland	Shortfall at Ross		Potential for shortfalls at Gin Gin	Potential for inertia shortfall
South Australia	Synchronous condensers project underway	Shortfall extended to June 2023		
Tasmania	Potential for shortfall at several nodes	Potential for inertia shortfall	Shortfall from May 2024	Shortfall from May 2024
Victoria	Services in place at Red Cliffs until 2022			

Legend:	No shortfall	System strength or inertia services in place or underway	Potential shortfall (under review)	Shortfall

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1. Introduction

System strength and inertia are two of the important power system security services that need to be carefully planned as the Australian electricity system transitions.

As the power system transitions, AEMO is considering the impact of emerging trends on system security services such as system strength and inertia. These trends include the ongoing uptake of both utility and distributed inverter-based resources (IBR), lowering of minimum demands and low demand periods due to increasing uptake of distributed energy resources (DER), and temporary or permanent changes in behaviour of synchronous generators in the market.

The increasing penetration of IBR together with changes to operation of synchronous generators present a need for the Australian electricity sector to implement a world-leading energy transition that takes advantage of emerging technology as well as optimising the utility of existing assets.

This section outlines the regulatory context for this 2020 System Strength and Inertia (SSI) Report, and clarifies where this SSI Report sits within the framework of AEMO's planning documents.

Application of the current regulatory frameworks or the 2020 report

AEMO is required to determine the minimum system strength and inertia requirements in the National Electricity Market (NEM) and assess whether, in AEMO's reasonable opinion, there are or are likely to be any shortfalls within the next five years[4].

Both system strength and inertia are required for the robust and secure operation of the power system:

- A minimum level of system strength is needed for the power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance[5].
- A minimum level of inertia is also required in the power system to suppress and slow frequency deviations so that automatic controls can respond to sudden changes in the supply–demand balance[6].

This report applies the current frameworks for system strength and inertia. Separately, the market institutions in the NEM are considering broad-ranging regulatory changes for delivery of system strength and inertia services.

AEMO applies the System Strength Requirements Methodology[7] to determine the system strength requirements for each region of the NEM by selecting fault level nodes and then assessing the minimum three phase fault level required at each node.

AEMO's assessment for system strength is based on normal operating conditions[8]. These requirements do not necessarily have to be met at all times operationally, for example under reduced output from distributed photovoltaics (PV) and variable renewable energy (VRE), or for planned outages of network elements, providing that system security can still be maintained.

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[4] Clauses 5.20.5 and 5.20.7 of the NER

[5] For more information on system strength, see AEMO, Power System Requirements, July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf and AEMO, System strength explained, March 2020, at https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

[6] For more information on inertia, see Power System Requirements, July 2020 at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf?la=en&hash=04F4669E6663B1763086B291B463C0A5.

[7] AEMO, System Strength Requirements Methodology, July 2018, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

[8] Studies assessing 'normal operating conditions' consider the system with all transmission network elements in service, except for elements that are out of service as part of the usual system configuration (for example to maintain system security). More information can be found in AEMO's Power System Security Guidelines, September 2019, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/power-system-operating-procedures.

The requirements take account of the stability of the region following any credible contingency event or protected event when determining system strength requirements (consistent with National Electricity Rules [NER] clause 5.20.7(b)). The determination of the requirements for system strength and inertia does not include investigation of the actions required to return the power system to a secure operating state within thirty minutes.

AEMO's responsibilities for system strength in the NEM

AEMO is responsible for determining system strength requirements for each region in the NEM. Under the NER, system strength is represented by the three phase fault level at designated fault level nodes[9]. For each fault level node, the minimum three phase fault level is determined and used as a basis for assessing system strength.

AEMO is responsible for publishing an annual report on system strength[10] which includes:

- AEMO's determination of system strength requirements for each region and its assessment of any fault level shortfall.
- A description of the system strength requirements[11] and details of its assessment of an existing or likely fault level shortfall over a planning horizon of at least five years.

Transmission network service providers (TNSPs) or jurisdictional planning bodies, as the system strength service providers for each region, are responsible for making system strength services available to meet any fault level shortfall related to decreasing supply of system strength in the region as synchronous generators that have historically been relied on to provide system strength withdraw from the market[12]. These services must be made available by a date nominated by AEMO which is at least 12 months from the declaration of the shortfall, unless an earlier date is agreed with the system strength service provider.

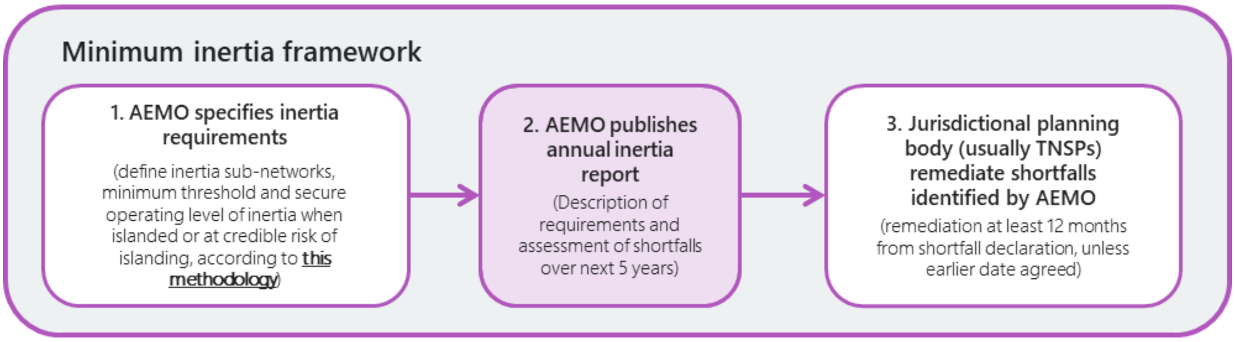
Separately, new generators being connected in the NEM must currently remediate their impact on system strength under the remediation (or 'do no harm') rules arrangements[13].

Appendix A2 of this report provides information on AEMO's assessment process for regional requirements and projections, and Section 2 provides the updated 2020 outcomes of these assessments as well as any previous assessments which have not been updated.

AEMO's responsibilities for inertia in the NEM

Figure 1 describes the regulatory framework in the NEM for assessing and remediating inertia.

Figure 1 Regulatory frameworks for inertia in the NEM



[9] Clause 5.20C.1 of the NER

[10] Clause 5.20.7 of the NER

[11] In September 2017, the AEMC introduced new Rules for managing system strength, see NER Clause 5.20C.

[12] Clause 5.20C.3 of the NER

[13] Clause 5.3.4B of the NER

This report meets AEMO's responsibility to publish an annual report on inertia[14], which includes:

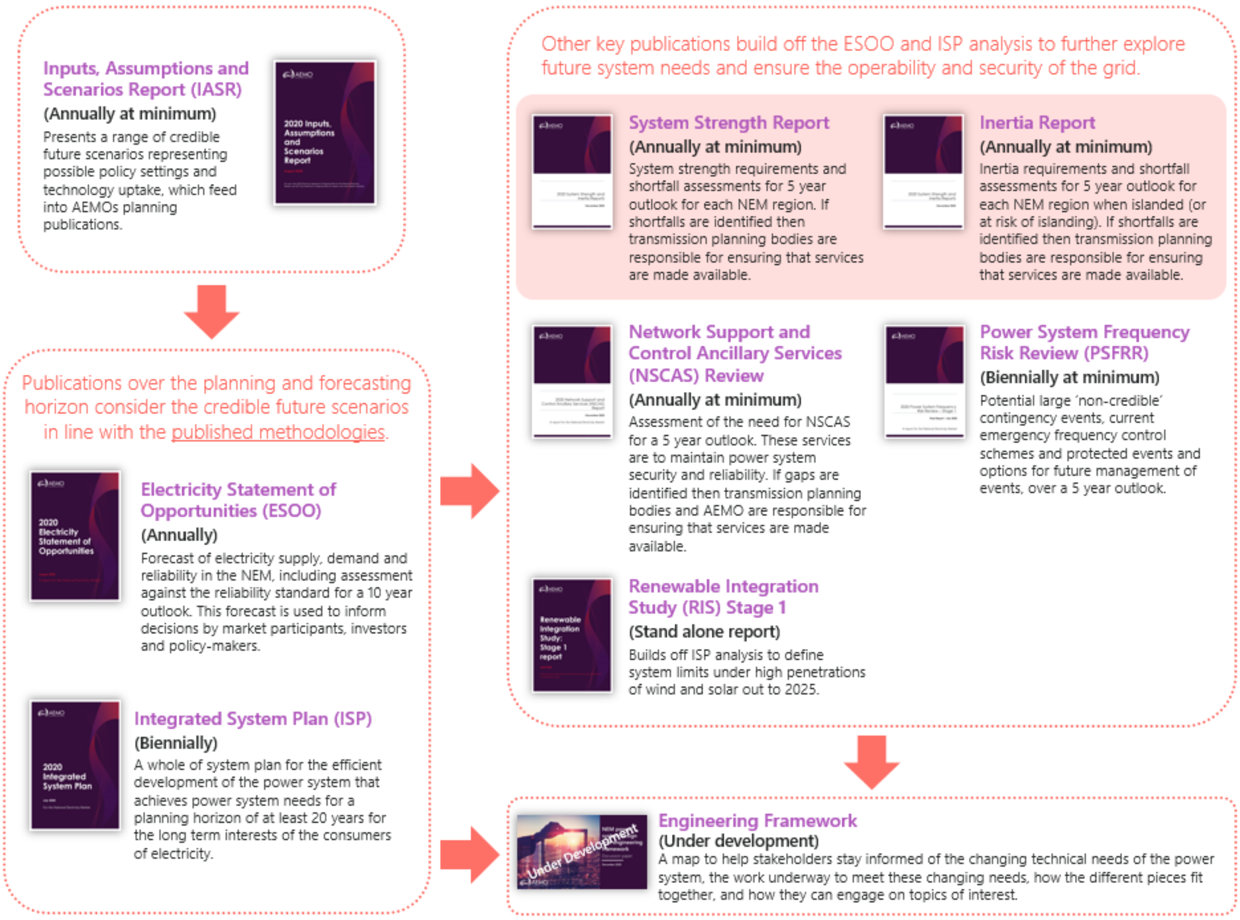
- Boundaries of inertia sub-networks and related inertia requirements.
- AEMO's assessments of any inertia shortfall.
- AEMO forecast of any inertia shortfall arising at any time within a planning horizon of at least five years.
- Inertia requirements for each inertia sub-network together with AEMO's assessment of level of inertia provided by the sub-network and any inertia shortfalls[15].

Appendix A2 of this report provides information on AEMO's assessment process for requirements and projections, and Section 2 provides the updated 2020 outcomes of these assessments, as well as any previous assessments which have not been updated.

AEMO's documents on planning for operability

This SSI Report uses inputs from a number of related reports and processes, and also informs and underpins other reports and processes owned by AEMO and TNSPs. Figure 2 shows the SSI Report in the context of other key AEMO planning and forecasting documents.

Figure 2 AEMO's planning and forecasting documents



Note: Clicking on an image of a report will take you to that report's location on the AEMO website.

[14] Clause 5.20.5 of the NER

[15] Clause 5.20B.3 of the NER

2. Regional requirements and outlooks

AEMO has applied the assessment methods and assumptions described in Appendix A2 to prepare regional requirements and outlooks for system strength and inertia. In this section, the updated (or existing) system strength and inertia requirements are provided (Sections 2.1 and 2.2) before an overview of the market projections considered (Section 2.3). Finally, an outlook for each region is given showing market outlook, network outlook, system strength and inertia projections, and declaration of any shortfalls (Sections 2.4 to 2.8). Appendix A1 provides a summary of the results of the projections across the NEM.

2.1 2020 system strength requirements

AEMO has applied the system strength assessment method in Section A2.1 to determine the system strength requirements in the NEM. These requirements are prepared consistent with the acceptable minimum synchronous machine combinations for each region of the NEM, as detailed in Appendix A3. Table 2 provides the updated set of system strength requirements and notes where these have changed from previous assessments.

AEMO has not formally changed the location of any fault level nodes in this report, although Section 2.2 does consider the potential for future update of fault level nodes in the New South Wales region. For the minimum fault level requirements which are updated in this report, Appendix A3 and Appendix A4 provide details of the model setup for the supporting electromagnetic transient (EMT) and steady state fault level analysis respectively.

Table 2 Fault level nodes and minimum three phase fault levels in the NEM for 2020

Region	Fault level node	2020 minimum three phase fault level (megavolt-amperes [MVA])		Difference from previous assessments
		Pre-contingency	Post-contingency	
New South Wales	Armidale 330 kilovolt (kV)	3,300	2,800	Newly declared in this report, reflecting reduced acceptable minimum synchronous machine combinations (Note 1).
	Darlington Point 330 kV	1,500	600	
	Newcastle 330 kV	8,150	7,100	
	Sydney West 330 kV	8,450	8,050	
	Wellington 330 kV	2,900	1,800	
Queensland	Gin Gin 275 kV	2,800	2,250	No change from April 2020 declaration, but analysis is ongoing for Ross and Gin Gin (Note 2).
	Greenbank 275 kV	4,350	3,750	
	Lilyvale 132 kV	1,400	1,150	
	Ross 275 kV	1,350	1,175	
	Western Downs 275 kV	4,000	2,550	

Region	Fault level node	2020 minimum three phase fault level (megavolt-amperes [MVA])		Difference from previous assessments
		Pre-contingency	Post-contingency	
South Australia	Davenport 275 kV	2,400	1,800	Updated to take into account the committed synchronous condensers at Davenport and Robertstown
	Para 275 kV	2,250	2,000	
	Robertstown 275 kV	2,550	2,000	
Tasmania	Burnie 110 kV	850	560	Updated to take into account more accurate models (Note 3).
	George Town 220 kV	1,450	-	No change from November 2019 declaration (Note 4).
	Risdon 110 kV	1,330	-	
	Waddamana 220 kV	1,400	-	
Victoria	Dederang 220 kV	3,500	3,300	Updated in this report, including updated assessment at Red Cliffs (Note 5).
	Hazelwood 500 kV	7,700	7,150	
	Moorabool 220 kV	4,600	4,050	
	Red Cliffs 220 kV	1,700	1,000	
	Thomastown 220 kV	4,700	4,500	

Notes:

1. New South Wales system strength requirements were previously determined in the 2018 requirements report (https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf), and reported for post-contingency levels only. This 2020 SSI Report reflects agreement between AEMO and TransGrid about changes to the minimum acceptable synchronous machine combinations for New South Wales, as well as providing the pre-contingency values.
2. Queensland system strength requirements were previously determined in the April 2020 report (https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-queensland-system-strength-requirements-and-ross-node-fault-level-shortfall.pdf?la=en#:~:text=Fault%20levels%20at%20Ross%20are,operation%20of%20inverter%2Dconnected%20resources), including moving the Nebo node to the Ross node, and reported for post-contingency levels only. Although these levels are not changed in this December 2020 report, AEMO expects changes for the Ross and Gin Gin nodes at least in 2021. Analysis is ongoing.
3. AEMO has re-assessed and updated the Burnie fault level requirements to incorporate new EMT models for existing wind farms close to the node.
4. Tasmania system strength requirements were last determined in the November 2019 report (https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf), and reported for pre-contingency levels only. This 2020 SSI Report updates the Burnie pre- and post-contingency values. More analysis is required to prepare the post-contingency values for the other Tasmania fault level nodes. AEMO and TasNetworks use the pre-contingency values to inform the operational arrangements for system strength requirements in Tasmania.
5. Victorian system strength requirements were previously determined in the 2018 requirements report (https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf) and then the November 2019 report (https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice_of_Victorian_Fault_Level_Shortfall_at_Red_Cliffs.pdf). A notice to market was also published in August 2020 about a change to the post-contingency level at Red Cliffs (https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en&hash=5C3EDDABDF81891B3989F6FF0466C486). This report incorporates the intervening changes to the network and provides the pre- and post-contingency values.

2.2 2020 inertia requirements

AEMO has applied the inertia assessment method in Section A2.2 to determine the inertia requirements in the NEM, as documented in Table 3.

In this SSI Report, AEMO has updated the minimum threshold and secure operating levels of inertia for the Queensland and Victoria regions. The South Australia secure operating level was updated in August 2020, and the New South Wales and Tasmania levels have not been changed but are reported here for completeness. AEMO has also assessed the South Australia and Victoria secure operating level as a ratio of synchronous inertia and fast frequency response, to acknowledge the growing importance of the use of fast frequency response.

Table 3 Inertia requirements in the NEM for 2020

Region	2018 inertia requirements		2020 requirements	
	Secure (megawatt seconds [MWs])	Minimum (MWs)	Secure (MWs)	Minimum (MWs)
Queensland	16,000	12,800	14,800	11,900
Victoria (note 1)	15,400	12,600	13,900	9,500
New South Wales (note 2)	12,500	10,000	12,500	10,000
South Australia (notes 3, 4)	6,000	4,400	Combination of synchronous inertia and fast frequency response (note 3)	4,400
Tasmania (note 5)	3,800	3,200	3,800	3,200

Notes:

1. Inertia requirements have been determined for Victoria incorporating fast frequency response capability provided by the planned Moorabool 300 megawatts (MW) battery expected for commissioning by calendar year end 2021 (https://www.neoen.com/var/fichiers/20201104-neoen-mr-vbb-announcement.pdf).
2. Consistent with AEMO's 2018 Inertia Requirements & Shortfall publication, islanding of New South Wales is not considered to be likely, due to the diversity and number of AC interconnectors that exist between New South Wales and the adjacent regions.
3. Inertia requirements have previously been determined for South Australia in the Notice of South Australia Inertia Requirements and Shortfall (https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en) published in August 2020. The requirements determined in this notice remain unchanged for 2020.
4. In the Notice of South Australia Inertia Requirements and Shortfall (https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en) published in August 2020, secure operating levels of inertia were determined for before and after the installation of four synchronous condensers with flywheels in South Australia, an approved contingent project (https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-main-grid-system-strength-contingent-project) due for completion by mid-2021. The required secure operating level of inertia for each case is represented as a combination of MW of fast frequency response (FFR) and MWs of inertial response from synchronous generators. Refer to Section 2.66 for further details.
5. Inertia requirements have previously been determined for Tasmania in the Notice of Inertia and Fault Level Shortfalls in Tasmania (https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf) published in November 2019. The requirements determined in this notice remain unchanged for 2020.

2.3 Market projections

In this assessment, AEMO has built on the 2020 ISP outcomes and undertaken further market modelling to reflect recent trends and emerging market conditions. This was used to project generation dispatch over the coming decade for use in assessments of potential shortfalls. While the 2020 SSI Report shares all the fundamental assumptions used in the 2020 ISP, it has also incorporated the latest minimum and maximum demand projections from the 2020 ESOO.

Using these updated forecasts, AEMO has leveraged a time-sequential model to simulate three different projections relevant for system strength and inertia:

- A **traditional operations** projection, applying announced retirement dates for synchronous generators in the NEM, or technical end-of-life dates where retirement dates are not announced. Changes to unit commitment profiles of existing thermal generation units are not considered.
- A **high renewable energy** projection, with increased uptake of both utility-scale and distributed IBR resources that also incorporates earlier-than-announced unavailability of thermal generation.
- A set of **high renewable energy with flexible operation** sensitivities, simulated for the financial year 2025-26 and 2029-30 with additional analysis of the potential impact of low market prices incentivising seasonal withdrawal or intraday decommitment of synchronous generation units.

Further information on the market methodology and assumptions is available in Appendix A2.5.

For New South Wales, Queensland and Victoria, all three sets of projections were used to assess any potential shortfalls. As the flexible operation sensitivities did not include any units in South Australia or Tasmania, only the traditional operations and high renewable energy projections were used to assess shortfalls in these regions. For the purpose of this report, only some projections are shown:

- Where shortfalls are identified in all projections, the chart for traditional operations is shown.
- Where no shortfall is identified in any projection, the chart for high renewable energy is shown.
- Where shortfalls are identified in some but not all projections, the charts for traditional operations and the flexible operations sensitivities are shown.

Each chart shows the results for 2021-22 to 2025-26, as well as the outlook to 2029-30 at the end of the forecast period. In addition, sensitivities are provided for flexible operation in 2025-26 to demonstrate the projected dispatch patterns that may potentially apply by 2025-26.

2.4 New South Wales outlook

System strength or inertia shortfalls are not yet considered likely for New South Wales in the next five years, but system strength shortfall risks are increasing. There is growing evidence that changes in operation of major power stations could lead to system strength shortfalls in the centre of the region. AEMO will analyse future system strength and inertia requirements to support the transition of the New South Wales energy system.

The system strength and inertia outcomes are heavily influenced by the potential for changes in operational profiles of coal-fired generation and increasing levels of distributed and utility scale IBR. The announced retirement of Liddell Power Station in 2023 is not expected to lead to system strength or inertia shortfalls in New South Wales. However, future decommitment or flexible operation of large synchronous generators at times of low or minimum demand in the region may lead to system strength shortfalls at the Newcastle and Sydney West fault level nodes. Reduction in online inertia in the New South Wales region will also result from decommitment or flexible operation.

The timing, magnitude and likelihood of system strength shortfalls for Newcastle and Sydney West is uncertain. Before AEMO can form an assessment that a shortfall is reasonably likely, as required by the NER, more work is required to increase:

- Technical certainty about the likelihood, size and scale of the potential shortfalls and their solutions. More detailed steady state and EMT analysis is required to understand the potential shortfalls, and to consider reallocating the fault level nodes in the New South Wales region to appropriately plan for the changing market dynamics in the region as significant new generation is commissioned in new areas of the state.

- Certainty around imminent withdrawal of synchronous generating units from the market at times of low demand. As more renewable generation is commissioned, there is growing evidence that synchronous generators may decommit more often and operate more flexibly, reducing provision of system services. The recently announced New South Wales Government policies are intended to accelerate the introduction of new renewable generation.

Declaration of any inertia shortfall for a region must also consider the likelihood of islanding. Consistent with AEMO's 2018 Inertia Requirements & Shortfall publication[16], islanding of New South Wales remains unlikely. This finding is largely driven by the diversity and number of alternating current (AC) interconnectors that exist between New South Wales and adjacent regions.

The remainder of this section provides commentary on the market and general network outlook for New South Wales, and then gives details for system strength and inertia projections.

2.4.1 New South Wales market and network outlook

Key drivers that could affect future system strength and inertia availability in New South Wales are:

- In the 'traditional operations' projection, a drop from 12 thermal units operating to 10 thermal units in 2029 due to Vales Point retiring at the end of its technical life.
- Risk of synchronous generating unit decommitment decisions as part of increased uptake of both utility-scale and distributed IBR and ongoing minimum demand reductions in the region.

Projected changes to numbers of synchronous machines online in New South Wales

Under the high renewable energy projection, analysis highlights the potential for a significant reduction in the number of synchronous units online at certain times in New South Wales. This reduction in energy and capacity could be met by new generation. However, system strength is locational, and the replacement generation is in different locations with different technology. There will be an increasing need to replace the system services provided by withdrawing synchronous generation, and possibly a revision of fault level nodes at which system strength is assessed.

Figure 3 shows the expected number of central New South Wales coal units dispatched under the traditional operations projection, the high renewable energy projection, and high renewable energy with flexible operation sensitivities. The minimum number of machines from the successful synchronous combinations[17] is also shown.

[16] AEMO, 2018 Inertia Requirements Methodology, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[17] Success criteria for synchronous machine combinations are listed in the AEMO System Strength Assessment Guidelines, June 2018, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2018/system_strength_requirements_methodology_published.pdf?la=en.

Figure 3 Projections for number of synchronous machines dispatched in New South Wales

Possible augmentations to reinforce supply to greater Sydney area

The possible reduction in the number of units online, combined with new generation remote from the major load centre at Sydney, is expected to lead to the network reaching thermal and other system security limitations at times of peak demand. The Sydney/Newcastle/Wollongong load centre reinforcement is included in the 2020 ISP as a Future Integrated System Plan (ISP) Project, with further information on this available in Appendix 3 of the 2020 ISP[18]. Solutions to address these limitations should consider both system security and reliability needs holistically in the best long term interests of consumers, in alignment with AEMO's ISP objectives.

Future fault level node allocation

The share of IBR generation in New South Wales is projected to grow rapidly over the next decade, particularly under the high renewable energy projection where earlier-than-expected withdrawal of synchronous generating units could occur from the mid-2020s.

In each region, there are nodes related to the four fault level node classifications defined in the Methodology[19], which for New South Wales are detailed in Table 4. Each node has been agreed with the relevant TNSP as being suitable to ensure the maintenance of power system security and the system standards.

The node in New South Wales representing the synchronous generation centre is Newcastle. This node is electrically close to the metropolitan load centre node of Sydney West. The requirements for each of these nodes is set on the basis that a number of synchronous machines are required to maintain power system security. As synchronous machines withdraw, the requirement to maintain the power system security may be able to be decoupled from the requirement to maintain these nodes at their existing levels.

[18] 2020 ISP Appendix 3, Section A3.5.3, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en.

[19] System Strength Requirements Methodology 2018 and System Strength Requirements and Shortfalls 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

In 2021, AEMO will reassess the existing fault level nodes in New South Wales and determine whether new fault level nodes should be introduced. AEMO will also update the minimum fault level requirements across the region over time. Steady state and EMT analysis will be undertaken based on generation mix projections in order to ensure that changes to the fault level nodes and requirements still ensure that power system security and the power system standards are able to be maintained.

2.4.2 New South Wales system strength outlook

The system strength outlook for New South Wales is shown in Table 4. Each node includes information on the fault level node class, relevant duration curves, whether the requirements are met now and at the end of the outlook period, and comments regarding the requirements.

The results in Figure 4 to Figure 10 show that there is the risk of shortfalls under the high renewable energy projection with flexible operation sensitivities at Newcastle and Sydney West. These potential shortfalls are due to market modelling outcomes where synchronous machines, which are needed for the provision of system strength and inertia, are not dispatched rather than there being an insufficient number of machines to provide these services.

The remaining existing nodes in New South Wales are shown to at least meet their minimum requirements for the outlook period to 2025-26.

For further details regarding the system strength analysis undertaken please refer to Appendices A2 and A4.

Table 4 New South Wales system strength outlook

Fault level node	Fault level node class	Duration curves	2020 minimum three phase fault level (MVA)		Requirements met		Comments
			Pre-contingency	Post-contingency	Current	Up to 2025-26	
Armidale 330 kV	• High IBR	Figure 4	3,300	2,800	Yes	Yes	
Darlington Point 330 kV	• High IBR • Remote from synchronous generation	Figure 5	1,500	600	Yes	Yes	Projections lower than 2020 ISP values due to Project EnergyConnect connection to Dinawan.
Newcastle 330 kV	• Synchronous generation centre	Figure 6, Figure 7	8,150	7,100	Yes	Yes, but some risk of future shortfall of 500 MVA to 1,600 MVA	Possible shortfalls result of decommitment or flexible operation of coal units.
Sydney West 330 kV	• Metropolitan load centre	Figure 8, Figure 9	8,450	8,050	Yes	Yes, but some risk of future shortfall of 200 MVA to 1,100 MVA	Possible shortfalls result of decommitment or flexible operation of coal units.
Wellington 330 kV	• High IBR	Figure 10	2,900	1,800	Yes	Yes	

Figure 4 System strength outlook for Armidale under the high renewable projection

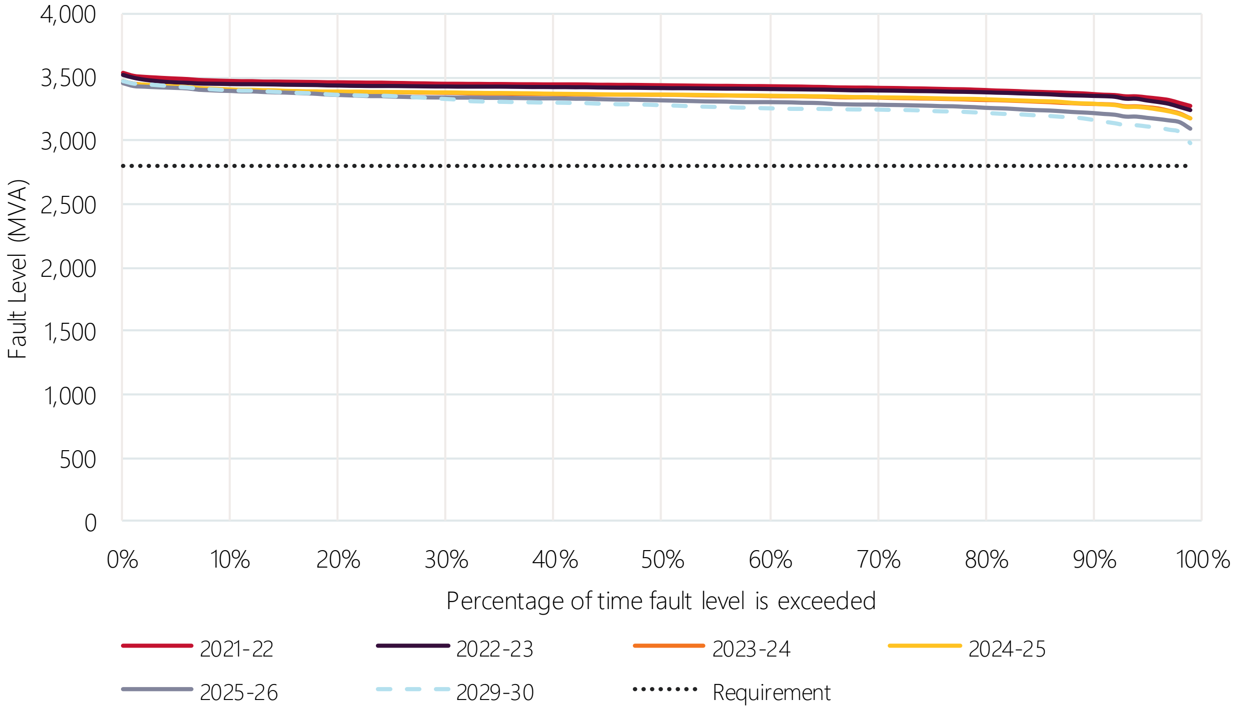


Figure 5 System strength outlook for Darlington Point under the high renewable projection

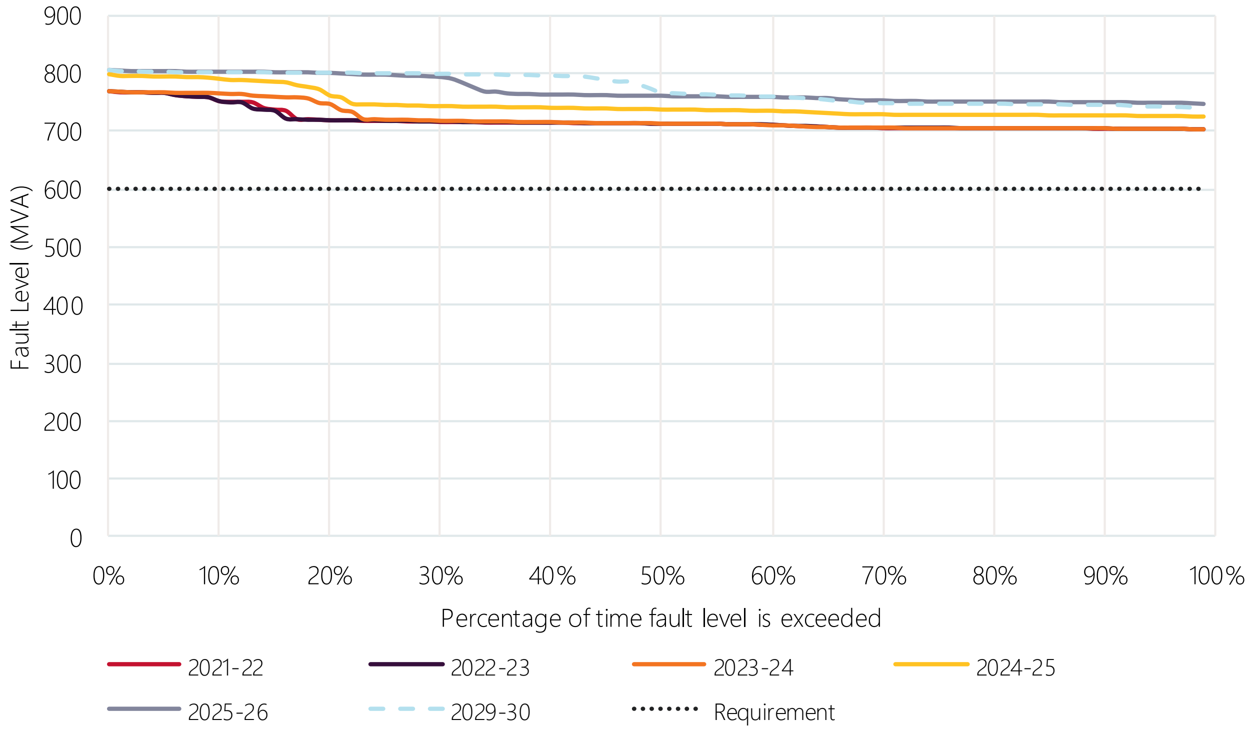


Figure 6 System strength outlook for Newcastle under the traditional operations projection

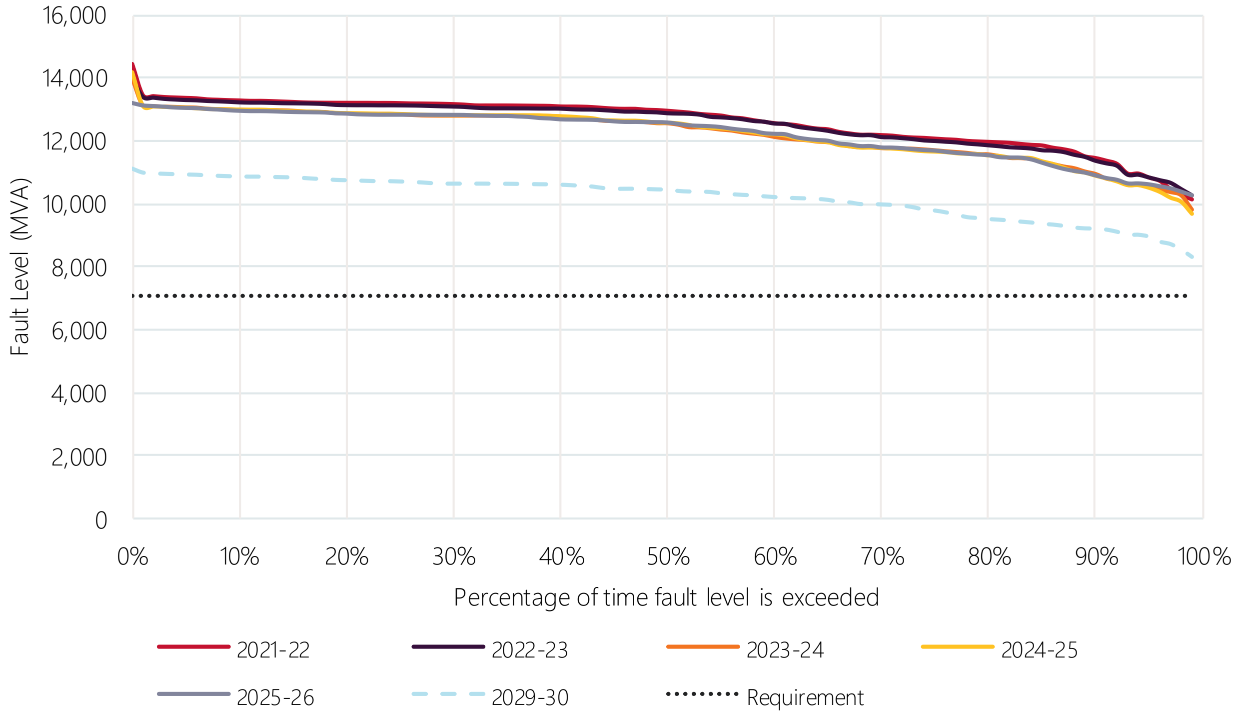


Figure 7 System strength outlook for Newcastle considering flexible operation

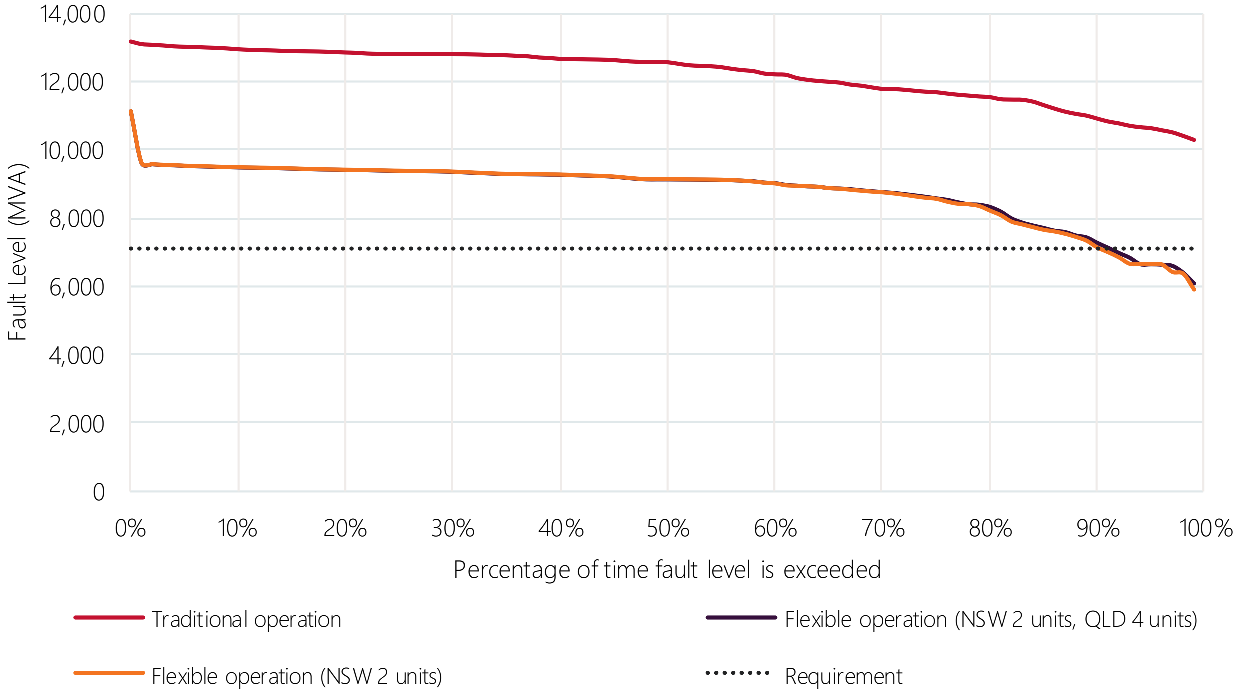


Figure 8 System strength outlook for Sydney West under the traditional operations projection

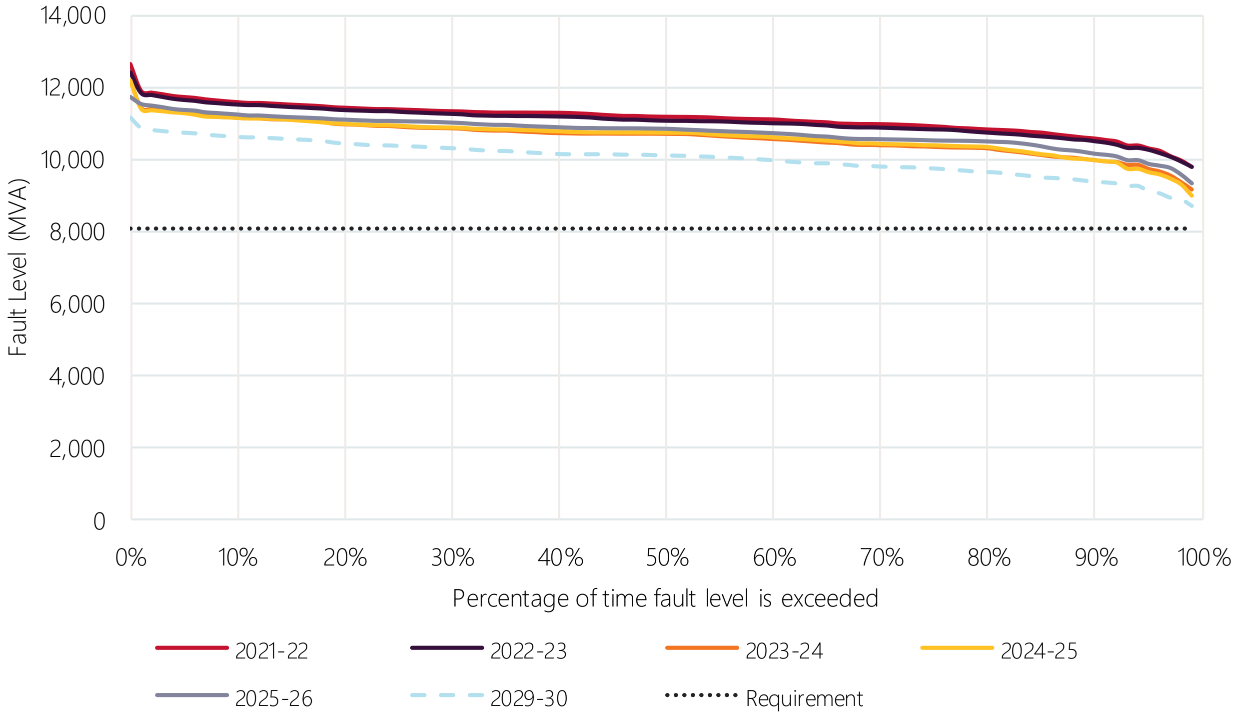


Figure 9 System strength outlook for Sydney West considering flexible operation

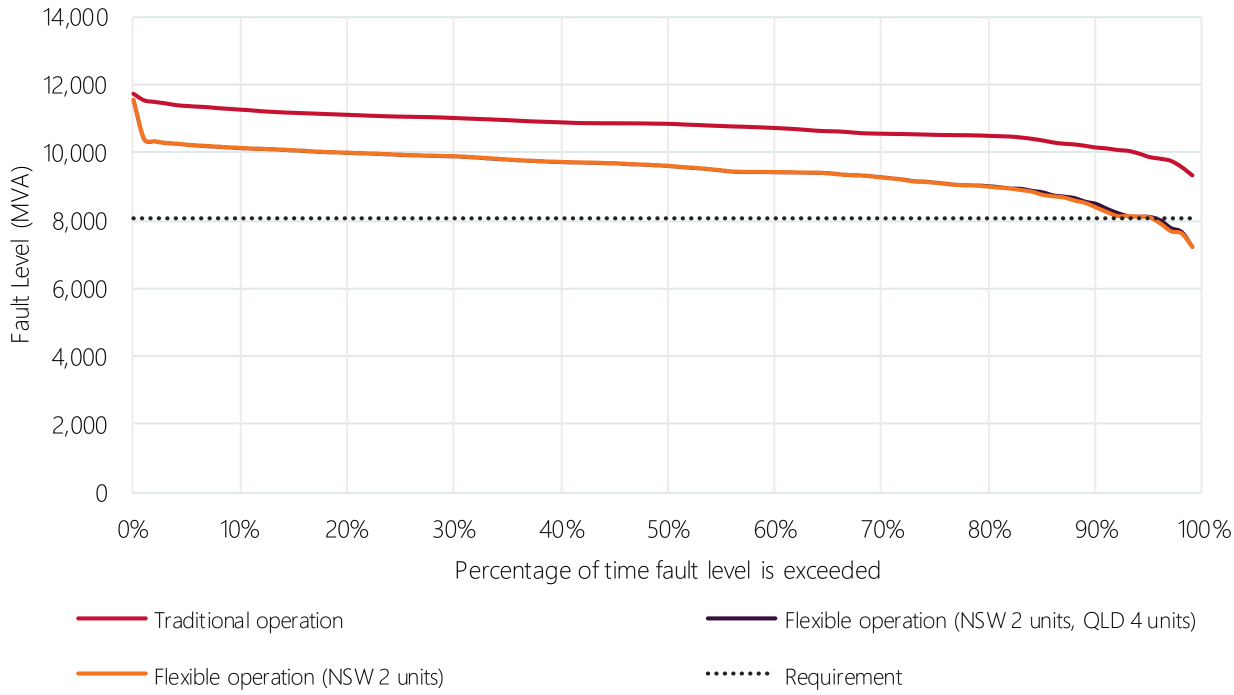
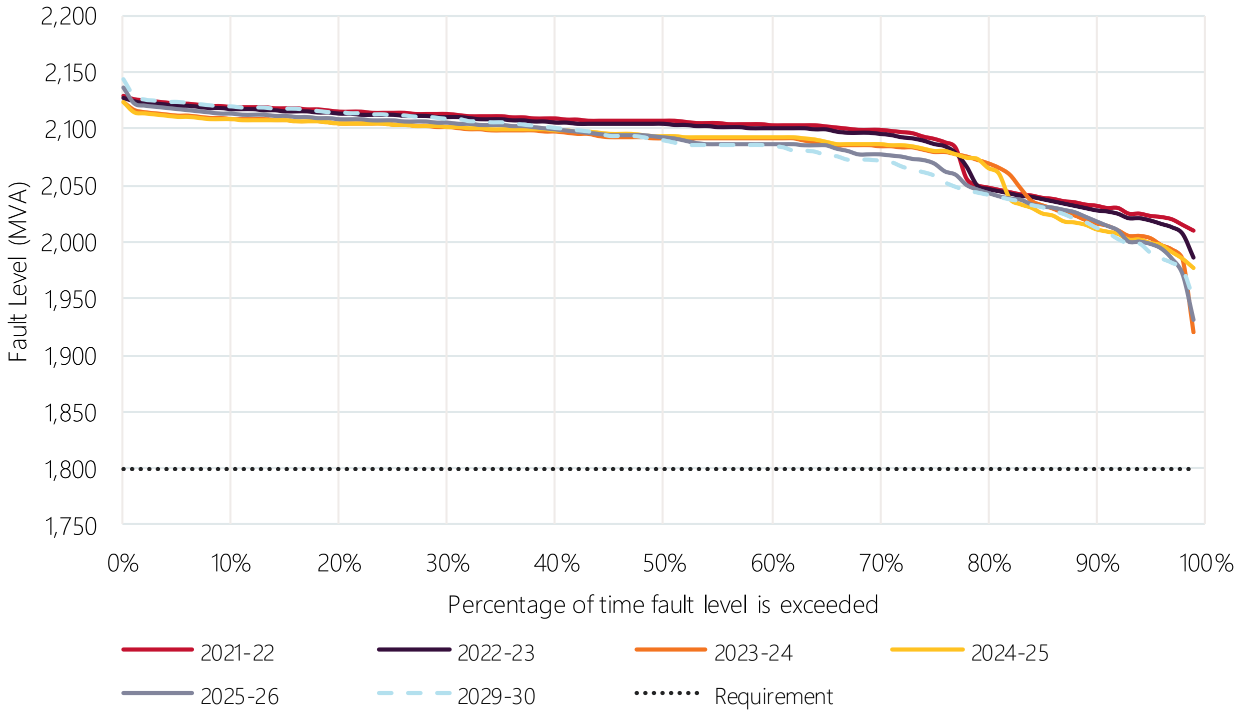


Figure 10 System strength outlook for Wellington under the high renewable projection



2.4.3 New South Wales inertia outlook

Using the inertia requirements determined in Section 2.2 and the shortfall projection and assessment methods described in Section A2.2 and Section A2.4, AEMO has assessed whether there is likely to be an inertia shortfall in the New South Wales region of the NEM, consistent with clause 5.20B.2 of the NER.

AEMO's assessment has been made by using inertia projections derived from the traditional operations and high renewable energy projections to calculate when the expected inertia online will not meet the inertia requirements for more than 99% of the time[20]. In addition, in accordance with the NER requirements, AEMO's assessment includes consideration of the likelihood of islanding. Consistent with AEMO's 2018 Inertia Requirements & Shortfall publication[21], islanding of New South Wales is not considered to be likely, due to the diversity and number of AC interconnectors that exist between New South Wales and the adjacent regions.

Figure 11 shows the projected inertia in New South Wales for the five-year outlook under the high renewable energy projection, against the minimum threshold level of inertia and the secure operating level of inertia (10,000 megawatt seconds [MWs] and 12,500 MWs respectively). Although the available inertia can be seen to dip below the secure operating level in the final year of the outlook period, it is not for more than 99% of the time.

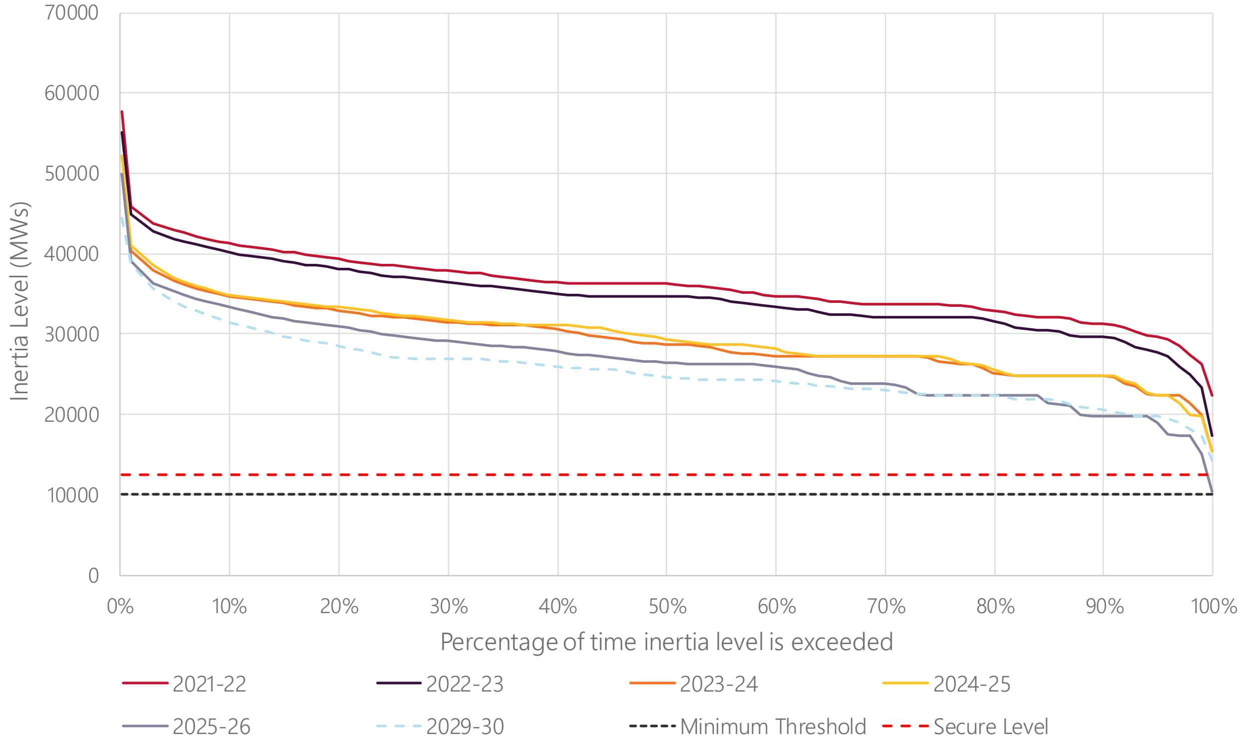
As such, for the five-year outlook, AEMO projects no likely shortfall in either the minimum threshold level of inertia or the secure operating level of inertia exists.

For further details regarding the inertia analysis undertaken, please refer to Appendix A5.

[20] This level has been selected considering the risks of excessive numbers of directions in real time operations against a reasonable efficient level of potential for intervention.

[21] AEMO, Inertia Requirements Methodology, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

Figure 11 Inertia outlook for New South Wales under the high renewable energy projection



2.5 Queensland outlook

System strength or inertia shortfalls are not yet considered likely for Queensland in the next five years, but shortfall risks are increasing. There is growing evidence that changes in operation of major power stations could lead to system strength shortfalls in the centre and north of the region. AEMO will analyse future system strength and inertia requirements to support the ongoing energy transition in Queensland.

The system strength and inertia outcomes for Queensland are heavily influenced by the potential for changes in coal-fired generation operational profiles and increasing levels of IBR. Under the high renewable energy projection and the high renewable energy with flexible operation projection:

- A reduced number of Central Queensland units online may lead to a system strength shortfall at Gin Gin. When considering the possibility of intra-day decommitment, these shortfalls may occur sooner as well as increase in duration and size.
- A reduced number of Southern Queensland units online may lead to a system strength shortfall at Greenbank and Western Downs.
- This combined reduction in number of units online may lead to an inertia shortfall for the Queensland region within the five-year outlook period.

The timing, magnitude and likelihood of system strength shortfalls for Queensland is uncertain. Before AEMO can form an assessment that a shortfall is reasonably likely, as required by the NER, more work is required to increase:

- Technical certainty about the size and scale of the potential shortfalls and their solutions. More detailed steady state and EMT analysis is required to understand the potential shortfalls.

- Certainty around imminent withdrawal of synchronous generating units from the market at times of low demand. As more renewable generation is commissioned, there is growing evidence that synchronous generators are decommitting more often and operating more flexibly, reducing provision of system services. The newly announced Queensland government's policy to support a number of renewable energy zones (REZs) across the state[22] is intended to accelerate the introduction of new renewable generation.

AEMO will continue to work with stakeholders on the Queensland system strength and inertia outcomes. This includes considering new information as it becomes available, updating assessments and providing updates as necessary.

The remainder of this section provides commentary on the market and general network outlook for Queensland, and then gives details for system strength and inertia projections.

2.5.1 Update to the Ross fault level shortfall

In April 2020, AEMO published the Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall[23] under Clause 5.20C.2(c) of the NER. The report declared an immediate fault level shortfall at the Ross 275 kilovolt (kV) node, forecast to continue beyond 2024-25.

Powerlink published an Expression of Interest (EOI) in April 2020[24] for both short-term and long-term solutions to address the shortfall at Ross, submissions for which closed in May. Powerlink received a very positive response to the EOI offering a range of system strength support services to address the fault level shortfall at Ross and have been working closely with AEMO on the proposed remediation approach.

Since that time, Powerlink has entered into a short-term agreement with CleanCo Queensland for system strength services in North Queensland until the end of December 2020.

In addition, Powerlink has commenced development of potential longer-term solutions for system strength requirements. A number of control system changes are under way or have been completed to a number of VRE generators in North Queensland. Studies to validate the benefits of the proposed changes over the longer term are ongoing.

In this report, AEMO has reduced the requirement for the Ross node in this report based on updated studies conducted with these control system changes. AEMO and Powerlink will continue to work together to ensure the final solution is able to meet the system strength requirements.

2.5.2 Queensland market and network outlook

Key drivers that could affect future system strength and inertia availability in Queensland are the risk of synchronous generating unit decommitment decisions from 2025 or earlier, as part of increased uptake of both utility-scale and distributed IBR and ongoing minimum demand reductions in the region.

There are also a number of separate initiatives underway to address the 'do no harm' system strength remediation requirements for new generation connections. These include Powerlink's announced delivery of 'system strength as a service' project[25] and a project supported by the Australian Renewable Energy Agency (ARENA) to prepare a 'cost-effective system strength' study[26].

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[22] See https://www.dnrme.qld.gov.au/energy/initiatives/queensland-renewable-energy-zones/about.

[23] AEMO, Notice of Queensland System Strength Requirements and Ross Node Fault Level Shortfall, April 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-queensland-system-strength-requirements-and-ross-node-fault-level-shortfall.pdf?la=en&hash=398E515E24B7022406B6B391F269CBBB.

[24] Powerlink, Request for System Strength Services, 9 April 2020, at https://www.powerlink.com.au/system-strength-consultations#:~:text=Powerlink%20commenced%20an%20Expression%20of,closed%20on%2013%20May%202020.&text=In%20June%202020%20AEMO%20approved,the%20end%20of%20December%202020.

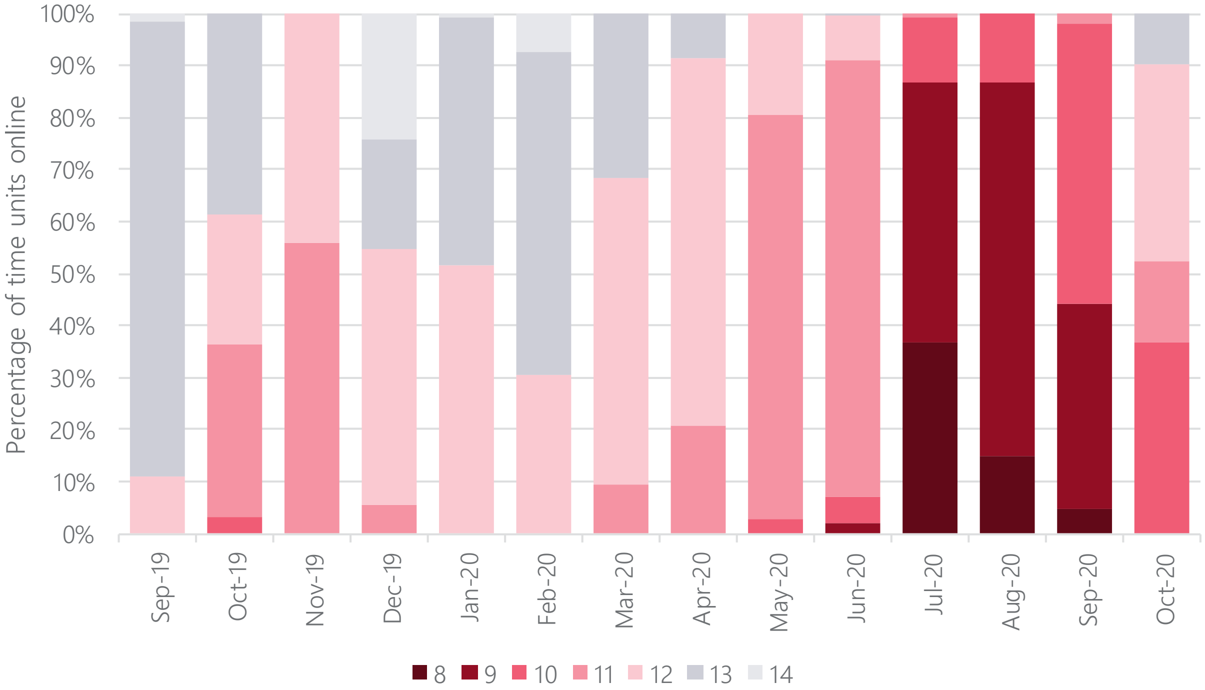
[25] Powerlink, 'Powerlink secures Australian-first system strength support model', October 2020, at https://www.powerlink.com.au/news-media/powerlink-secures-australian-first-system-strength-support-model.

[26] ARENA, 'Powerlink cost-effective system strength study', last updated December 2020, at https://arena.gov.au/projects/powerlink-cost-effective-system-strength-study/.

Changes in synchronous generator dispatch patterns

Historical data is showing changing dispatch patterns of Central Queensland coal units[27], indicating potential decommitment practices emerging in response to subdued market conditions, as shown in Figure 12. It is noted that, on average, the bid availability for these units has been significantly lower than the Projected Assessment of System Adequacy (PASA) availability in January to September 2020.

Figure 12 Central Queensland coal units online, monthly distribution September 2019 – October 2020



Projected changes to numbers of synchronous machines online in Queensland

Under the traditional operations projection, Queensland wholesale energy market price projections are in decline and daytime prices are frequently expected to reduce below the estimated short run marginal cost of most coal-fired power stations. This trend signals the risk that coal power stations may explore different operating regimes which might include intra-day decommitment, seasonal withdrawal, and/or lowering of minimum generating levels, subject to technical capabilities and commercial implications of these regimes.

Figure 13 outlines how the number of coal-fired generation units online could evolve under the high renewable energy with flexible operation sensitivities. Under this projection, by 2025-26, the number of coal units online in low demand conditions could be significantly lower relative to recent history.

[27] Callide B, Callide C, Gladstone and Stanwell

Figure 13 Number of Queensland coal units online, historical v high renewable energy with flexible operation

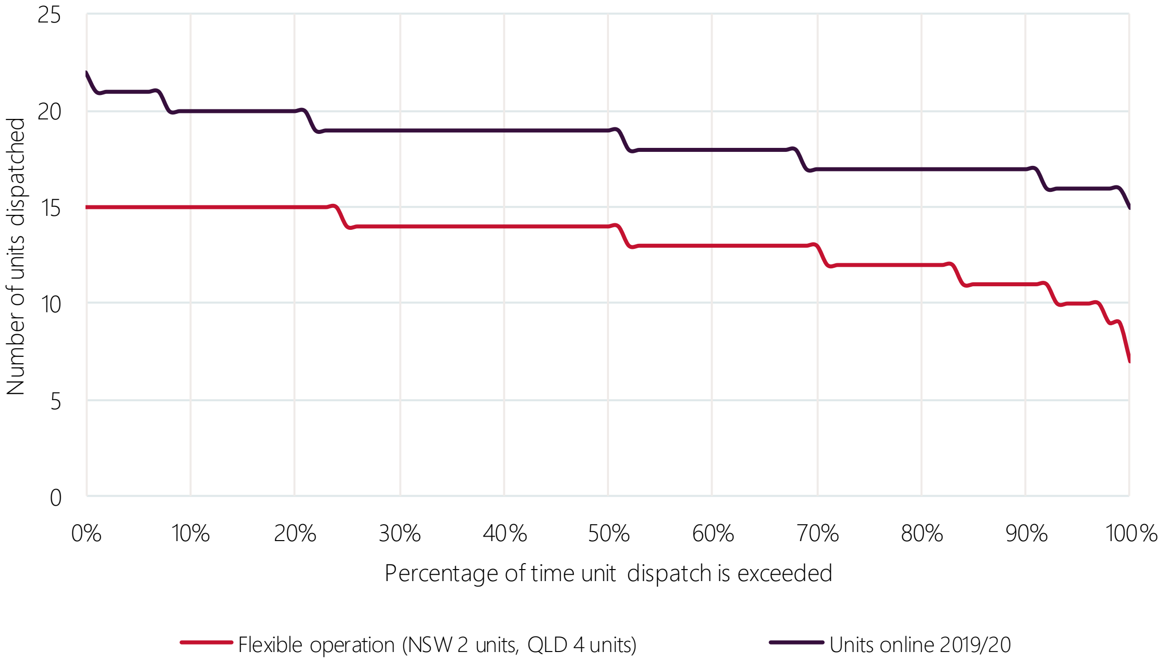
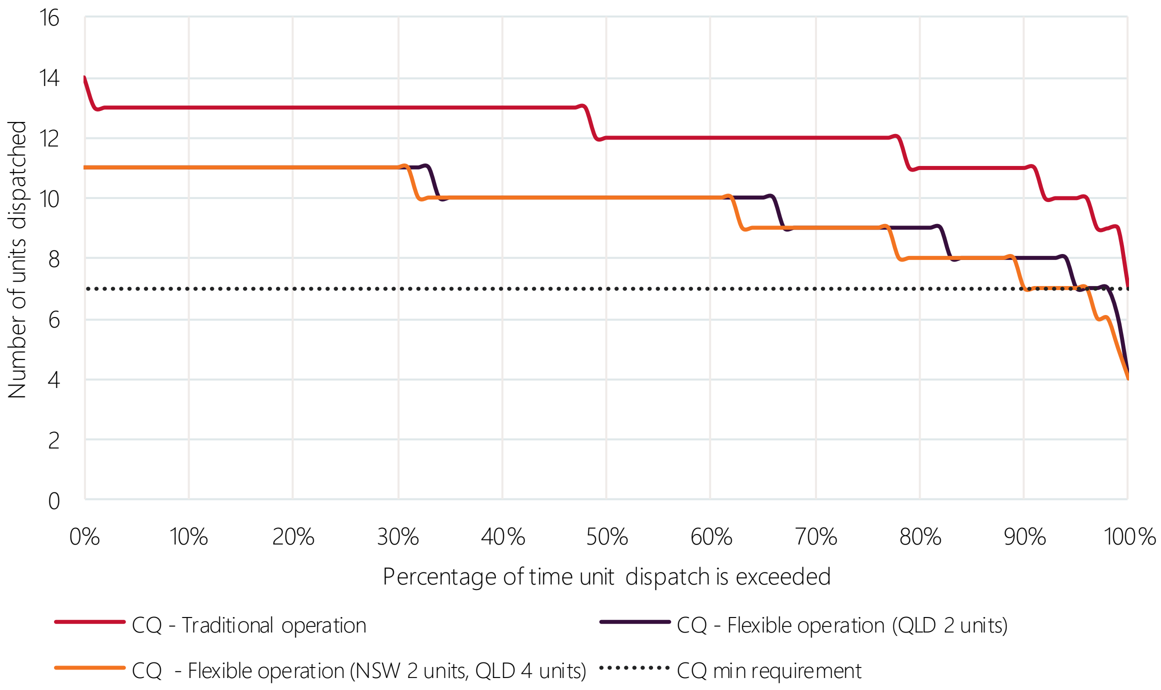


Figure 14 shows the expected number of central Queensland coal units dispatched for the traditional operations projection and the high renewable energy and flexible operation sensitivities, as well as the requirement for the minimum number of machines online (refer Section A3.1.1).

Figure 14 Number of synchronous machines dispatched in central Queensland



Impact on the central Queensland grid section

Increasing generation export from northern Queensland to supply major load centres in central and southern Queensland, coupled with reduced generation in central Queensland, is projected to lead to thermal overloads of 275 kV transmission lines between Bouldercombe and Calliope River and between Calvale and Wurdong following a credible contingency.

The flow on the central to southern Queensland (CQ–SQ) corridor is also projected to exceed the voltage and transient stability limit for a loss of Calvale–Halys 275 kV line. This trend can also be seen in the fault level projections for Queensland, with increased contribution at some of the more northerly nodes and reduced contribution at other nodes.

The Gladstone grid section and CQ–SQ reinforcements are included in the 2020 ISP as a Future ISP Project, with further information on this available in Appendix 3 of the 2020 ISP[28].

Solutions to address this should also consider system strength mitigation – a holistic approach to addressing power system needs would be in the best long-term interest of consumers.

Possible augmentations to improve transfer from Central Queensland (CQ) to Southern Queensland (SQ)

Increased generation in northern and central Queensland will likely need to be transferred to the load centre in southern Queensland through the CQ–SQ grid section. Maximum power transfer from CQ–SQ is currently limited by transient and voltage stability limitations. Currently, the upper limit of CQ–SQ transfer is 2,100 MW. Potential decommitment of coal-fired generation in the CQ area would reduce the availability of inertia and dynamic voltage support and would reduce CQ–SQ transfer capability. This may limit the dispatch of increased renewable generation from northern central Queensland to southern Queensland.

Preferred solutions to reinforce supply to Gladstone grid section and increase the CQ–SQ stability limit are identified in the 2020 ISP as Future ISP projects with preparatory activities, and further information on possible solutions is available in Appendix 3 of the 2020 ISP[29]. The timing will depend on the timing of any changes to future availability of central Queensland generating units to the market and additional new renewable generation locating in northern and central Queensland.

2.5.3 Queensland system strength outlook

The system strength outlook for Queensland is shown in Table 5. Each node includes information on the fault level node class, relevant duration curves, whether the requirements are met now and at the end of the outlook period, and comments regarding the requirements.

The results in Figure 15 to Figure 20 show there is the risk of a system strength shortfall at Gin Gin under the flexible operation sensitivities. As noted in Section 2.5.1, while studies are ongoing, AEMO has not yet declared a shortfall at Ross. Although Western Downs is approaching its limits in the high renewable energy projection, the remaining Queensland nodes are shown to at least meet the minimum requirements for the outlook period to 2025-26.

For further details regarding the system strength analysis undertaken, please refer to Appendices A2 and A4.

[28] 2020 ISP Appendix 3, Section A3.5.3, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en.

[29] 2020 ISP Appendix 3, section A3.5.2 Central Queensland to Southern Queensland Transmission Link and A3.5.4 Gladstone grid reinforcement, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en.

Table 5 Queensland system strength outlook

Fault level node	Fault level node class	Duration curves	2020 minimum three phase fault level (MVA)		Requirements met		Comments
			Pre-contingency	Post-contingency	Current	Up to 2025-26	
Gin Gin 275 kV	Synchronous generation centre	Figure 15 and Figure 16	2,800	2,250	Yes	Yes, but risk of shortfall of up to 100 MVA	Unavailability / flexible operation of central Queensland could lead to shortfalls from 2023-24
Greenbank 275 kV	Metropolitan load centre	Figure 17	4,350	3,750	Yes	Yes	
Lilyvale 132 kV	High IBR Remote from synchronous generation	Figure 18	1,400	1,150	Yes	Yes	
Ross 275 kV	High IBR Remote from synchronous generation	Figure 19	1,350	1,175	Pending review in 2021	Pending review in 2021	Draft assessment resulting in revised requirement*
Western Downs 275 kV	Synchronous generation centre	Figure 20	4,000	2,550	Yes	Yes	2025-26 is just meeting the requirement

* Refer to Section 2.5.1 for more information on the Ross shortfall.

Figure 15 System strength outlook for Gin Gin under the traditional operations projection

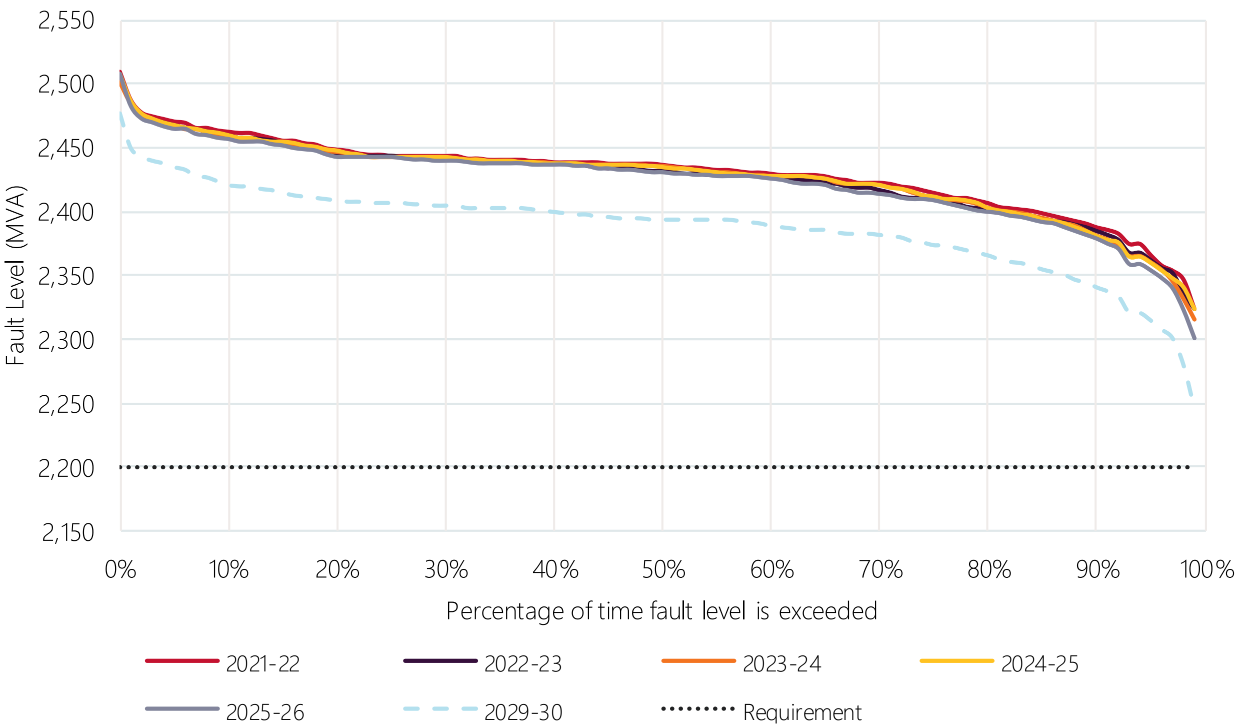


Figure 16 System strength outlook for Gin Gin considering flexible operation

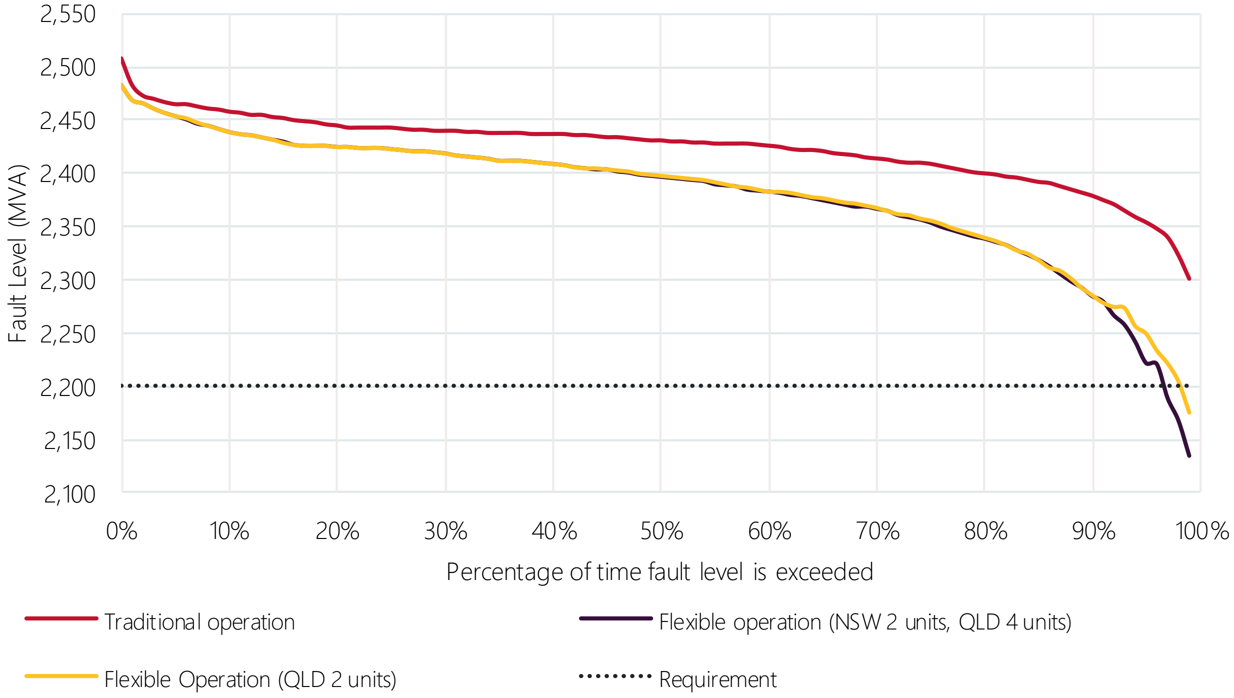


Figure 17 System strength outlook for Greenbank under the high renewable projection

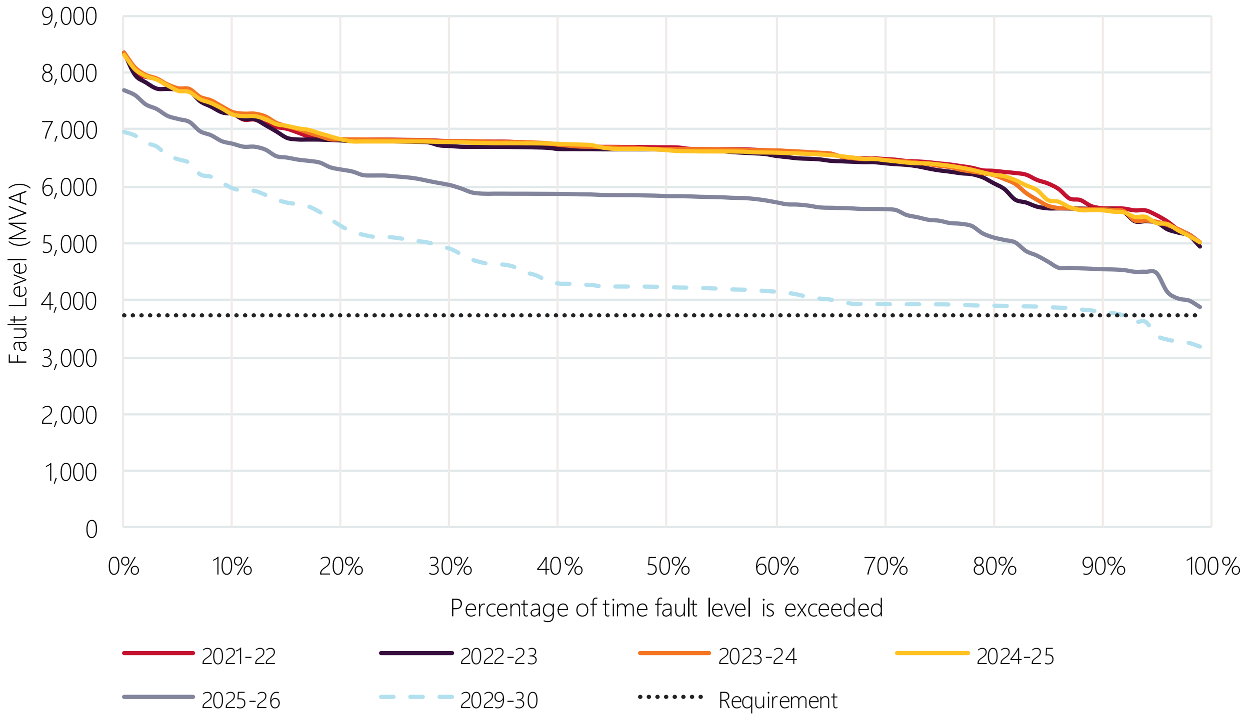


Figure 18 System strength outlook for Lilyvale under the high renewable projection

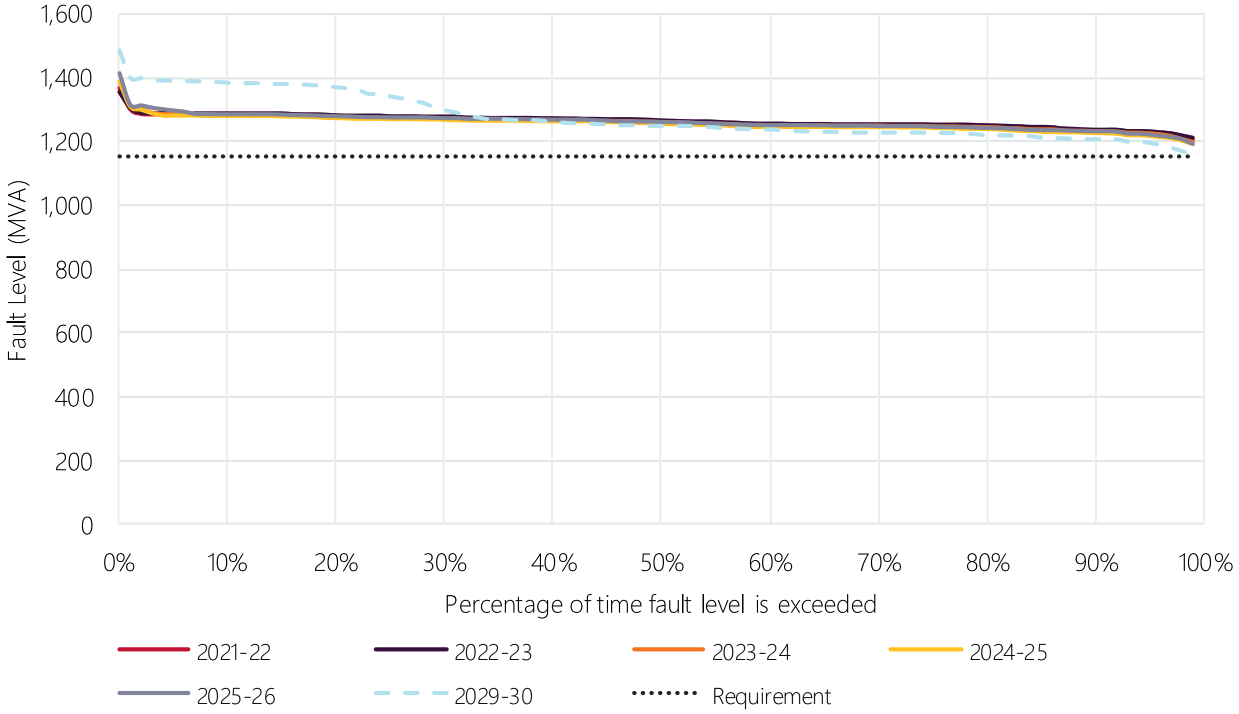
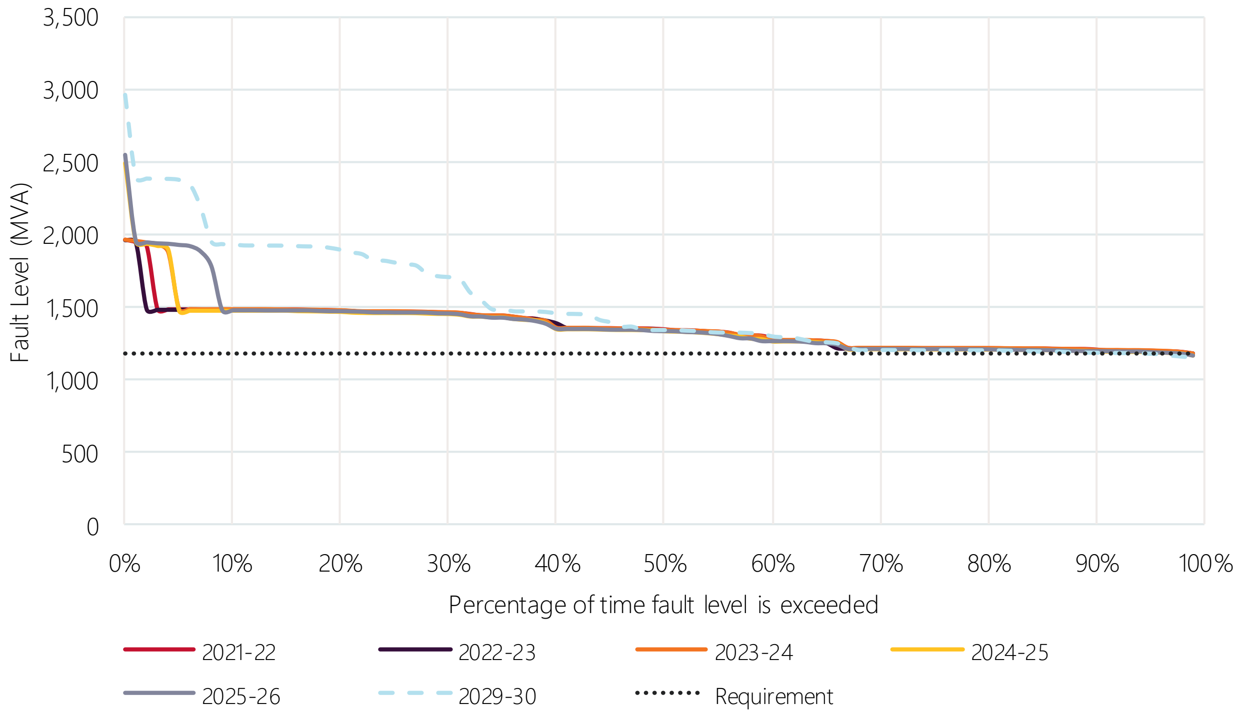
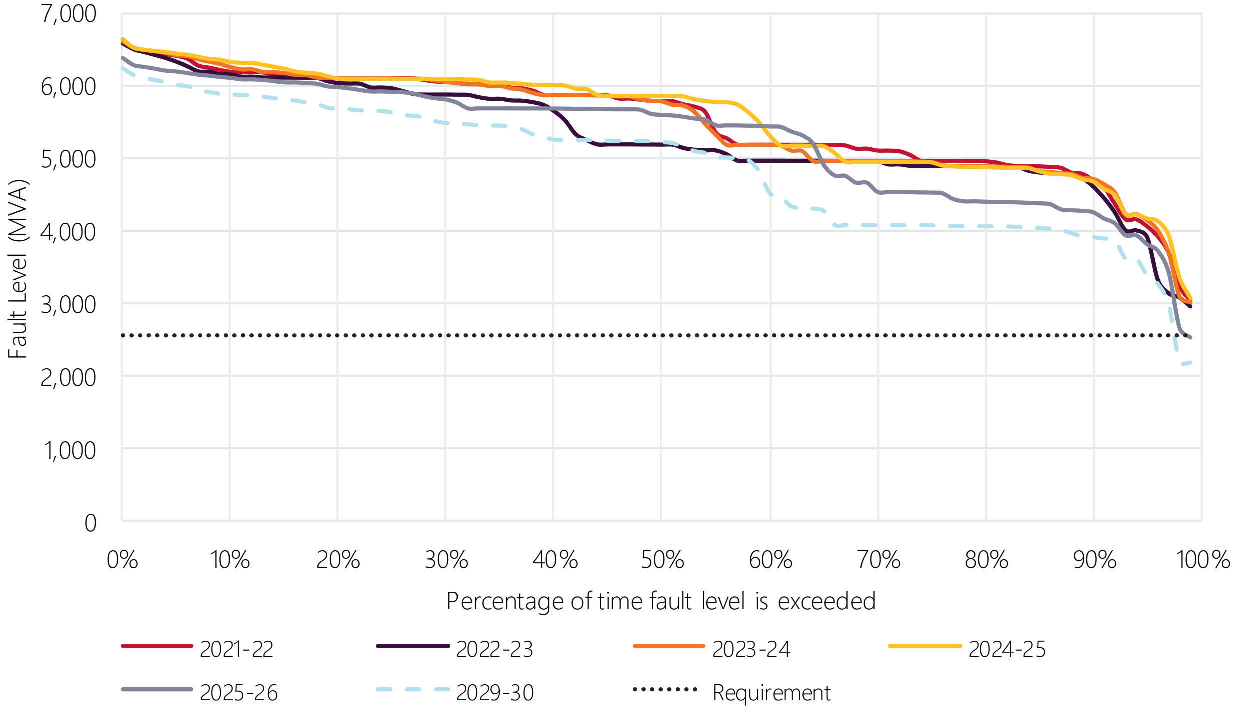


Figure 19 System strength outlook for Ross under the high renewable projection



* Refer to Section 2.5.1 for information on the fault level requirement for the Ross node.

Figure 20 System strength outlook for Western Downs under the high renewable projection



2.5.4 Queensland inertia outlook

Using the inertia requirements and the shortfall projection and assessment methods described in Section A2.2, AEMO has assessed whether there is likely to be an inertia shortfall in the Queensland region of the NEM, consistent with clause 5.20B.2 of the NER.

AEMO's assessment has been made by using inertia projections derived from the traditional operations projection, high renewable energy projection, and the high renewable energy with flexible operations projection, to calculate when the expected inertia online will not meet the inertia requirements for more than 99% of the time, as outlined in Section A2.4.

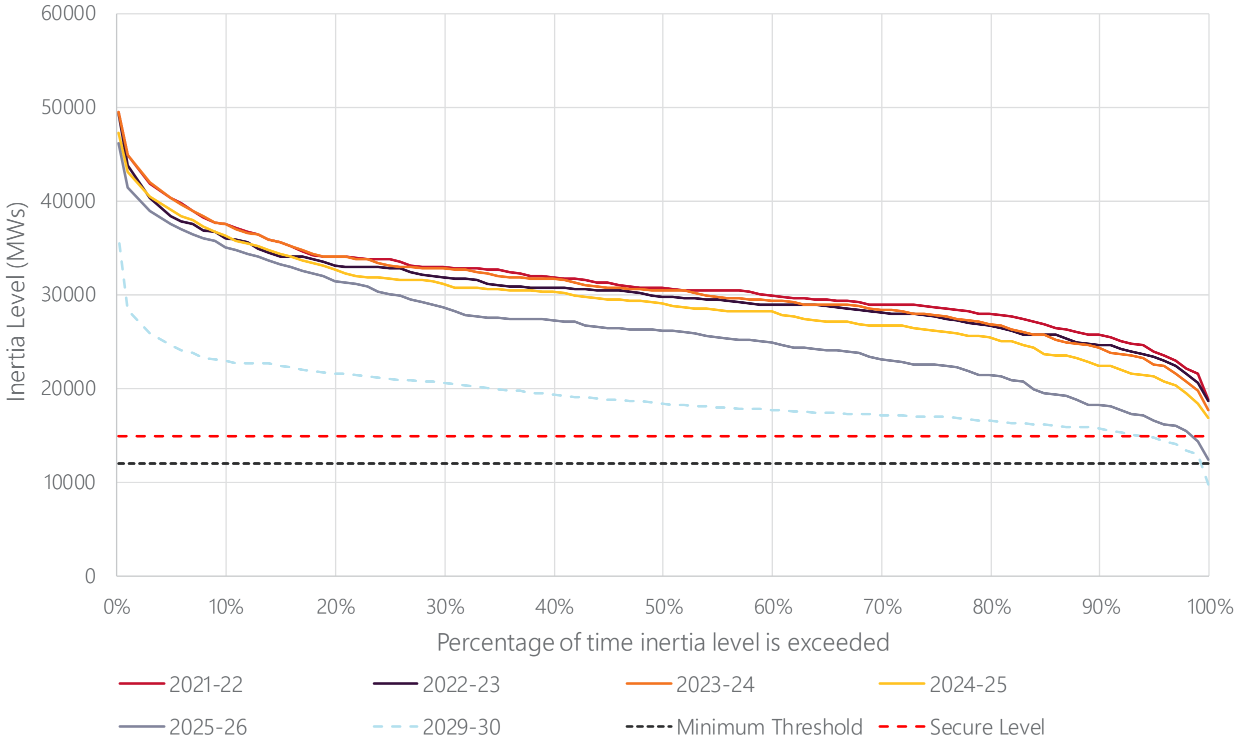
In accordance with the NER requirements, AEMO's assessment includes consideration of the likelihood of islanding. Consistent with AEMO's 2018 Inertia Requirements & Shortfall publication[30], the likelihood of islanding of the Queensland region remains non-remote. This finding is largely driven by Queensland having only one double circuit AC interconnection to New South Wales via the Queensland – New South Wales Interconnector (QNI)[31].

Figure 21 shows the projected inertia in Queensland for the five-year outlook under the high renewable energy projection, against the minimum threshold level of inertia and the secure operating level of inertia (11,900 MWs and 14,800 MWs respectively).

[30] AEMO, Inertia Requirements Methodology, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[31] While the Directlink converters allow for power transfer between New South Wales and Queensland, as it is HVDC technology, it is not a synchronous interconnection.

Figure 21 Inertia outlook for Queensland under the high renewable energy projection



For the period to 2024-25, AEMO projects that the minimum threshold level of inertia will be met. In the high renewable energy projection, AEMO forecasts a shortfall in inertia below the secure operating level from 2025-26 as a result reduced number of synchronous generating units projected to be online. The projected 99th percentile for available inertia in 2025-26 for the high renewable energy projection is 14,350 MWs, which accounts for a 450 MWs shortfall in the secure operating level of inertia for Queensland.

An inertia shortfall is not being declared by AEMO at this stage, due to the projected shortfall being linked to the same drivers and uncertainties as the potential system strength shortfalls, and therefore unable to be assessed as reasonably likely at this stage. AEMO will continue to monitor the prevailing situation in Queensland and potentially declare a shortfall in future assessments should conditions change.

For further details regarding the inertia analysis undertaken, please refer to Appendix A5.

2.6 South Australia outlook

System strength and inertia outlooks in South Australia are largely unchanged, with the installation of synchronous condensers ongoing and with ElectraNet continuing to pursue addressing the inertia shortfall declared in August 2020. In this report, AEMO extends that inertia shortfall by one year.

Two major projects are underway or under consideration which will support the delivery of system strength and inertia requirements for South Australia over time:

- ElectraNet is installing four synchronous condensers fitted with flywheels to meet the short-term requirements for system strength and inertia in South Australia, and is currently assessing how to address an inertia shortfall declared in August 2020.
- In addition, ElectraNet and TransGrid have submitted a contingent project application to increase the interconnection between South Australia and New South Wales through Project EnergyConnect.

Further information regarding these projects has been provided in Section A2.8.

In August 2020, AEMO declared two stages of inertia shortfalls for 2020-21 and 2021-22, but inertia shortfalls in future years were not declared, because the potential net distributed PV disconnection in future years following contingency events was highly uncertain. Since that time, the South Australian Government has introduced regulatory changes affecting the behaviour of new distributed PV in that state in response to system disturbances[32]. As a result, this uncertainty has now reduced and in this 2020 SSI Report AEMO declares an extension to that inertia shortfall for one more year, but does not increase the size of the shortfall. Uncertainty beyond 2022-23 remains, as Project EnergyConnect is not yet a committed project. If Project EnergyConnect proceeds, no further inertia shortfalls are subsequently projected for South Australia once it is in place.

The remainder of this section provides commentary on the market and general network outlook for South Australia, and then gives details for system strength and inertia projections and the extension of the inertia shortfall.

2.6.1 South Australia market and network outlook

AEMO is currently intervening in the market to ensure system strength requirements are met on a day-to-day basis. The installation of synchronous condensers (fitted with flywheels) at Davenport and Robertstown is projected to meet the system strength requirements and the minimum level of inertia in the South Australia region from 2021.

The establishment of additional interconnector capacity between South Australia and New South Wales is currently under consideration in the form of Project EnergyConnect. If committed, Project EnergyConnect will increase the transfer capacity into and out of South Australia, increase the sharing of system strength between the regions, and reduce the likelihood of the region becoming islanded from the rest of the NEM. Further information on Project EnergyConnect can be found in A3.4.2 of the 2020 ISP[33].

2.6.2 South Australia system strength outlook

The system strength outlook for South Australia is shown in Table 6. Each node includes information on the fault level node class, relevant duration curves, whether the requirements are met now and at the end of the outlook period, and comments regarding the requirements.

The installation of synchronous condensers at Robertstown and Davenport as part of the South Australian System Strength Project, to be in service by mid-2021, will meet the system strength requirements for the outlook period.

The results in Figure 22 to Figure 24 show that the nodes in South Australia at least meet their minimum system strength requirements for the outlook period to 2025-26. This analysis includes the AEMO planning assumption that at least two synchronous generating units remain online for system security purposes until the commissioning of Project EnergyConnect (modelled in 2024-25).

For further details regarding the system strength analysis undertaken, please refer to Appendices A2 and A4.

[32] Government of South Australia, Regulatory Changes for Smarter Homes, September 2020, at https://energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes.

[33] 2020 ISP Appendix 3, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en.

Table 6 South Australia system strength outlook

Fault level node	Fault level node class	Duration curves	2020 minimum three phase fault level (MVA)		Requirements met		Comments
			Pre-contingency	Post-contingency	Current	Up to 2025-26	
Davenport 275 kV	• High IBR • Remote from synchronous generation	Figure 22	2,400	1,800	Yes	Yes	Previously declared shortfalls being addressed by installation of four new synchronous condensers in South Australia.
Para 275 kV	• Metropolitan load centre • Remote from synchronous generation	Figure 23	2,250	2,000	Yes	Yes	
Robertstown 275 kV	• High IBR • Remote from synchronous generation	Figure 23	2,550	2,000	Yes	Yes	

Figure 22 System strength outlook for Davenport under the high renewable projection

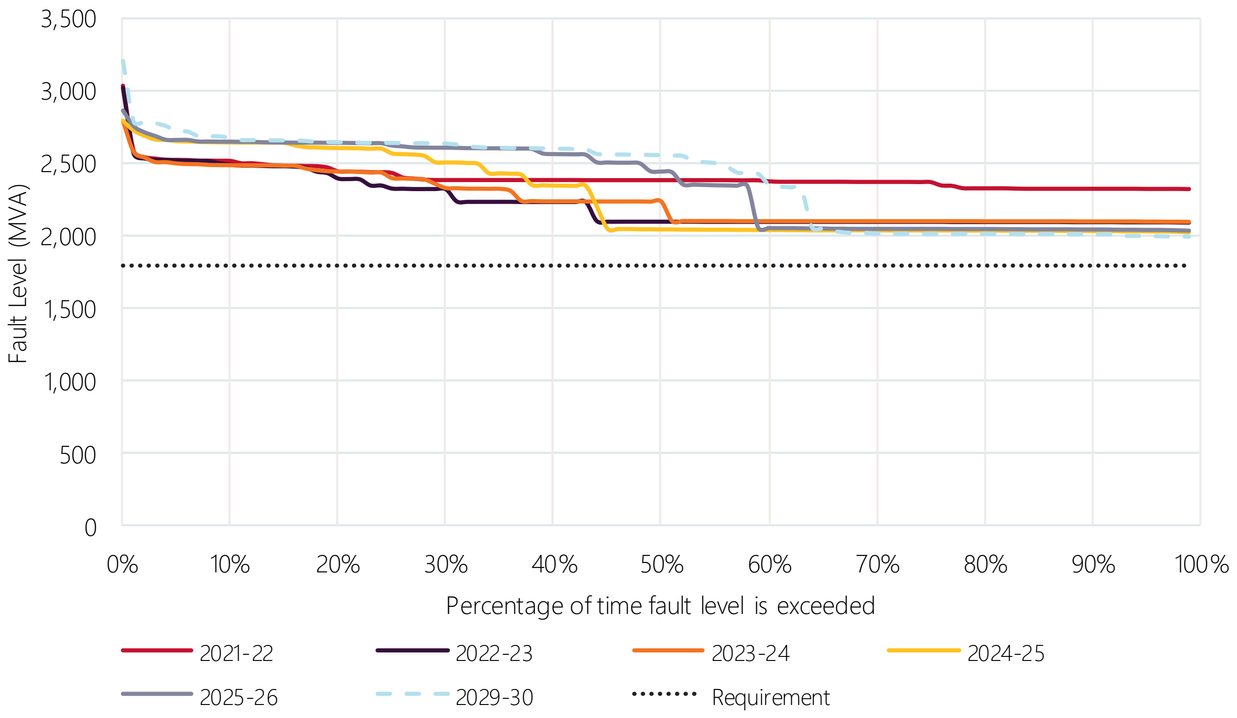


Figure 23 System strength outlook for Para under the high renewable projection

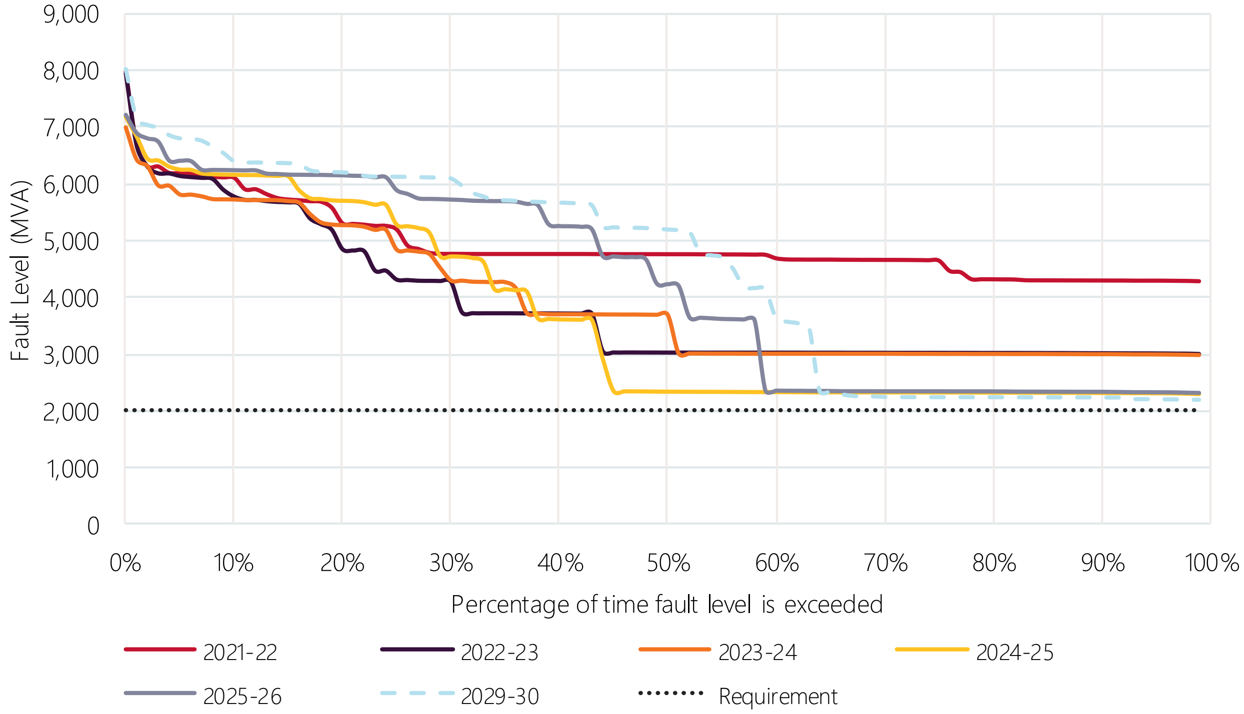
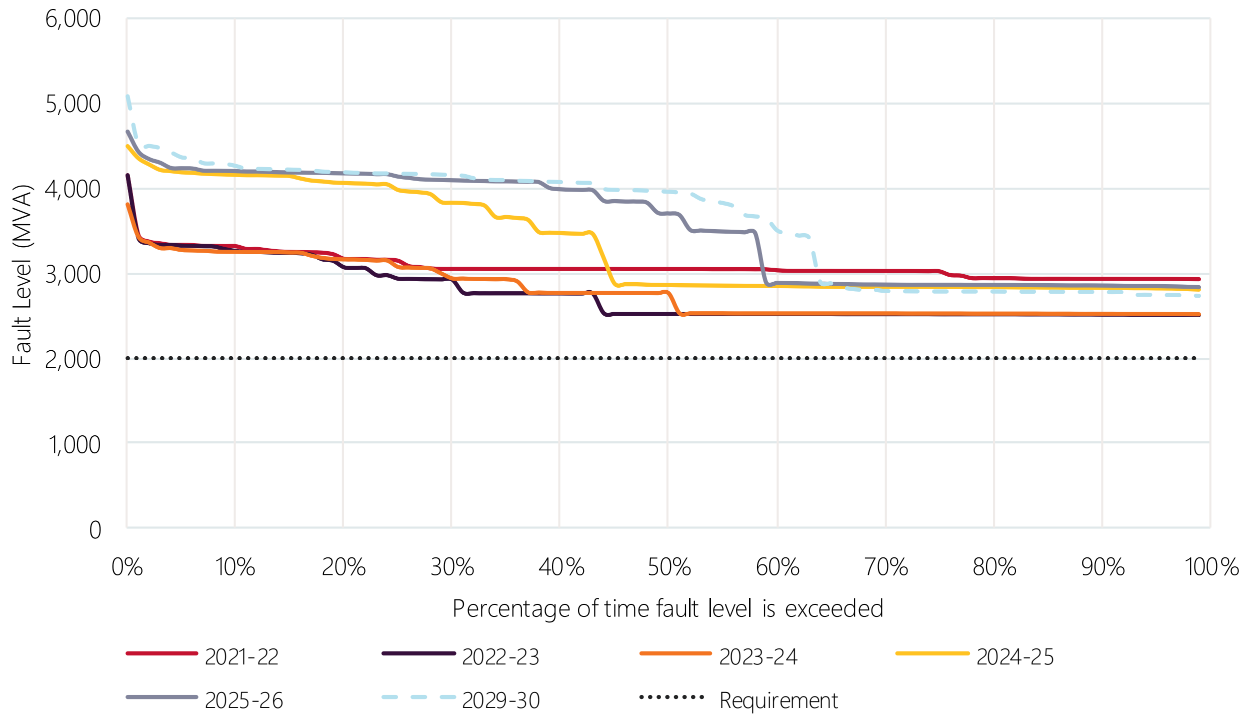


Figure 24 System strength outlook for Robertstown under the high renewable projection



2.6.3 South Australia inertia outlook

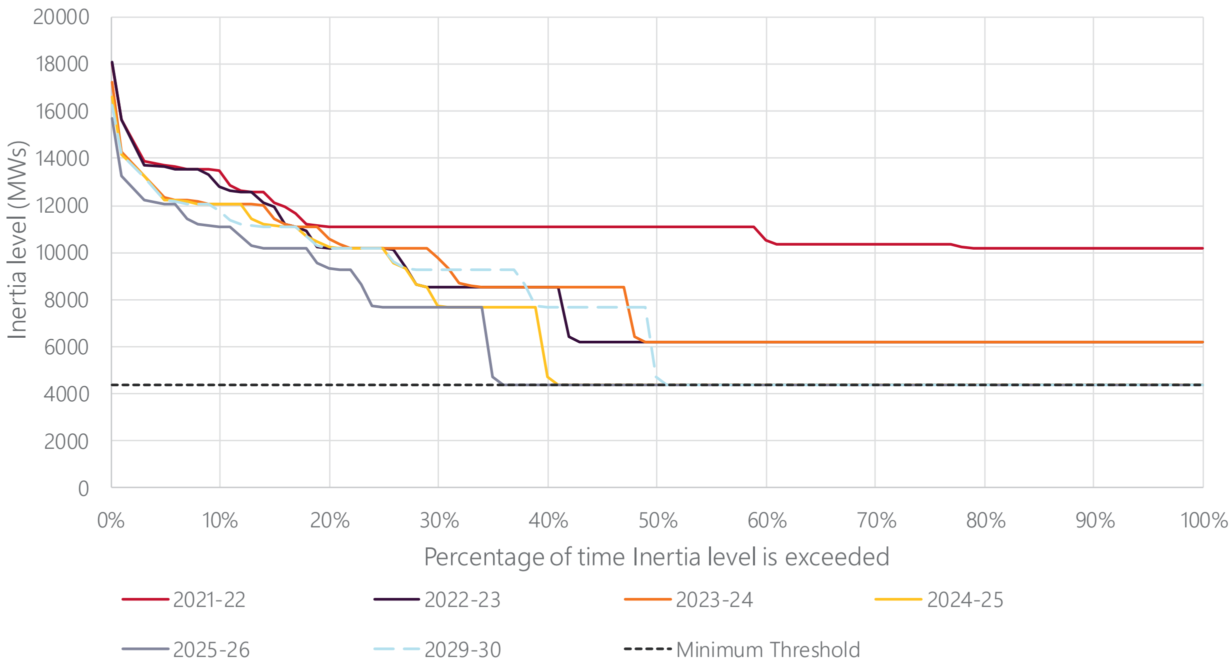
Using the inertia requirements and the shortfall projection and assessment methods described in Section A2.2 and Section A2.4, AEMO has assessed whether there is likely to be an inertia shortfall in the South Australia region, consistent with clause 5.20B.2 of the NER.

AEMO's assessment has been made by using inertia projections derived from the traditional operations and high renewable energy projections as outlined in Section A2.5 to calculate when the expected inertia online will not meet the inertia requirements for more than 99% of the time. In addition, in accordance with the NER requirements, AEMO's assessment includes consideration of the likelihood of islanding. Consistent with AEMO's 2018 Inertia Requirements and Shortfall publication[34], islanding of South Australia remains non-remote. This finding is largely driven by South Australia having only one double circuit AC interconnection to Victoria via the Heywood interconnector.

Figure 25 shows the projected inertia in South Australia for the five-year outlook under the traditional operations projection, against the minimum threshold level of inertia (4,400 MWs). The secure operating level of inertia is not represented as a fixed inertia level for South Australia for the 2020 assessment, but rather as a function of the amount of fast frequency response (FFR) made available in the South Australian region (see Figure 26). Previous analysis conducted in the Notice of South Australia Inertia Requirements and Shortfall[35] outlined how the increasing provision of FFR, predominantly from battery energy storage systems, helped reduce the requirements for synchronous inertia in the secure operating levels of inertia within the South Australia region.

For the period to 2025-26, AEMO has assessed that the minimum threshold level of inertia (4,400 MWs) will be met. However, a shortfall is projected for the secure operating level of inertia in South Australia (see Table 8). For further details regarding the inertia analysis undertaken, please refer to Appendix A5.

Figure 25 Inertia outlook for South Australia under traditional operations projection



[34] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[35] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en.

Projection for meeting minimum threshold level of inertia

AEMO declared a system strength shortfall for South Australia in 2017[36], resulting in ElectraNet procuring four synchronous condensers for installation in the South Australian region. Following this, in 2018 AEMO declared an inertia shortfall for the South Australian region as part of the 2018 National Transmission Network Development Plan (NTNDP)[37]. To meet this gap, high inertia flywheels were included in the design of the synchronous condensers being procured by ElectraNet. This will meet the minimum threshold component of the inertia gap (4,400 MWs) declared by AEMO.

Projection for meeting secure operating level of inertia

In the Notice of South Australia Inertia Requirements and Shortfall [38] published in August 2020, inertia shortfall projections were not declared beyond 2021-22, because of high levels of uncertainty regarding the potential net distributed PV disconnection in future years following contingency events. At the time, AEMO was working with the South Australian Government to determine interim measures and mechanisms to address emerging problems posed by distributed PV generation while new standards for inverter based distributed generation were being developed.

This work is now complete, and has led to the South Australian Government's Regulatory Changes for Smarter Homes rule implementations[39]. Effective application of the South Australian Government's new rules should ensure that the net distributed generation loss can no longer grow with the installation of new PV generating systems. Hence, the levels of net generation PV loss forecast for the 2021-22 period can be carried forward to future planning years with greater certainty. Combining this with the deteriorating inertia outlook from 2021-22 to 2022-23 (as seen in Figure 25) implies that the shortfall in the secure operating level of inertia which was previously declared to 2021-22 can now be carried forward to 2022-23.

Uncertainty remains in projections beyond 2022-23, due to future network augmentations, in particular Project EnergyConnect, which is a new AC interconnector between South Australia and New South Wales being jointly developed by ElectraNet and TransGrid. It is currently pending regulatory assessment as a contingent project, with possible commissioning from late 2023. It is likely that no inertia shortfalls will be declared for the South Australia region following the commissioning of a second double circuit AC interconnector, as the likelihood of the South Australia region islanding would be significantly reduced.

Fast frequency response services recommended to address shortfall

In the August 2020 Notice of South Australia Inertia Requirements and Shortfall, AEMO recommends FFR from batteries (or another appropriate technology) needs to be incorporated as part of the solution to meet the secure operating level of inertia in South Australia. Depending on the amount of FFR that can be made available, through inertia support activities or otherwise, there may also be a need to increase the amount of synchronous generation online during islanded operation.

Figure 26 shows the inertia requirements for secure operating levels of inertia adjusted for assumed inertia support activities including FFR, in the period after the four synchronous condensers are commissioned in South Australia.

Areas greyed out in the figure highlight the likely boundaries of secure operation, by removing areas where:

(a) Minimum demand conditions may prevent the addition of inertia[40].

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[36] AEMO. Update to the 2016 NTNDP, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Second_Update_to_the_2016_NTNDP.pdf.

[37] AEMO. National Transmission Network Development Plan, December 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

[38] AEMO, Notice of South Australia Inertia Requirements and Shortfall, August 2020, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en.

[39] Government of South Australia, Regulatory Changes for Smarter Homes, September 2020, at https://energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes.

[40] The sum of the minimum generator stable generation levels sets a maximum inertia from synchronous generation. The level shown is approximate and will also depend on factors such as synchronous generator availability and Murraylink capacity. As the synchronous condensers provide inertia with no minimum generation output, the total inertia that can be placed online increases by 4,400 MWs.

(b) Inertia is already assumed to be available for system security purposes, with at least two synchronous generating units to be online[41].

(c) The limit of capacity of existing/committed installed utility-scale batteries is reached[42].

It is expected that each point along the line would be a secure operating point for the studied contingencies, with each point made up of a combination of synchronous inertia (MWs) and fast frequency response (MW). The more FFR is available, the lower the required inertia response. The new synchronous condensers will provide 4,400 MWs of synchronous inertia, and this sets the minimum threshold of inertia.

Daytime requirements are taken as operating levels of inertia adjusted for FFR, as they are greater than the night-time requirements.

Figure 26 South Australia secure operating level of inertia adjusted for inertia support activities, with four synchronous condensers with flywheels

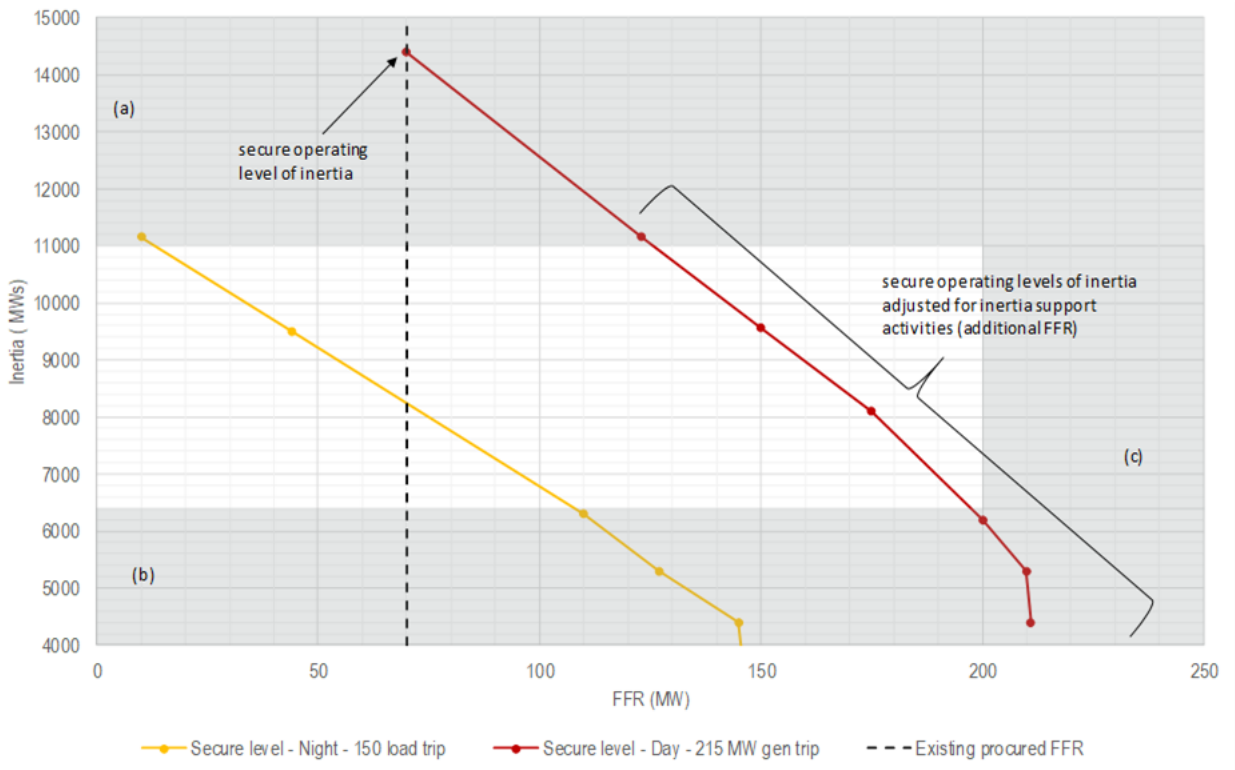

Table 7 reports FFR/inertia combinations of secure operating levels of inertia for South Australia after the four synchronous condensers are commissioned, and compares them against the projected 99th percentile inertia for the relevant year. Combinations of FFR and inertia for which an inertia shortfall exists are shown in red; those where there is no shortfall are shown in green. This table identifies combinations for which there would likely be a shortfall, and also the level of FFR that could reduce or remove the shortfall. For example, Table 7 shows that with 175 MW of FFR contracted, the required level of synchronous inertia would be 8,100 MWs. This is greater than the 99th percentile inertia of 6,200 MWs, therefore a shortfall would exist. By contrast, with 200 MW of FFR contracted, the 99th percentile inertia is equal to the required synchronous inertia and there is no shortfall.

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[41] Minimum of 6,400 MWs of inertia is assumed for planning purposes to be online due to system security requirements for at least two synchronous generating units online when all four synchronous condensers are online.

[42] Includes the Hornsdale Power Reserve 50 MW extension.

Alternatively, in Table 8, secure operating levels of inertia adjusted for inertia support activities have been subtracted from the 99th percentile projected inertia, showing the shortfall in synchronous inertia for a given fast frequency response level that would need to be filled.

The FFR values in Table 7 and Table 8 include the existing 70 MW of available FFR reserves, so the quantity of FFR needing to be procured would be 70 MW lower than any value in these tables.

Table 7 Comparison of 99th percentile projected inertia after four synchronous condensers installed in South Australia, adjusted for inertia support activities

Year	Projected 99th percentile inertia (MWs)	Secure operating level of inertia (SOLI) adjusted for inertia support activities, fast frequency response (FFR)/inertia combinations							
		SOLI FFR (MW)	70	123	150	175	200	210	211
2022-23	6,200	SOLI Inertia (MWs)	14,390	11,150	9,560	8,100	6,200	5,300	4,400

Table 8 Inertia shortfalls at different levels of FFR for Stage 2 secure operating level of inertia, adjusted for inertia support activities

Year	Secure operating level of inertia (SOLI) adjusted for inertia support activities, FFR/inertia combinations							
	SOLI FFR MW)	70	123	150	175	200	210	211
2022-23	Inertia shortfall MWs)	-8,190	-4,950	-3,360	-1,900	No shortfall	No shortfall	No shortfall

Figure 26, Table 7 and Table 8 were taken from the 2020 Notice of South Australia Inertia Requirements and Shortfall and represented a range of possible secure operating points for different combinations of installed synchronous inertia (MWs) and fast frequency response (MW) to address the shortfall declared for the 2021-22 period. These results are applicable for the shortfall now being declared for the 2022-23 period, as the 99th percentile forecast level of inertia (6,200 MWs) is the same as that previously projected for the 2021-22 period in the 2020 Notice of South Australia Inertia Requirements and Shortfall.

Extension of South Australia inertia shortfall

ElectraNet is the Inertia Service Provider in South Australia. AEMO had requested from ElectraNet that the required services for Stage 1 be made available from 1 October 2020. On 30 September 2020, Hornsdale Power Reserve (HPR) and the South Australian Government agreed to increase the capacity reservation for HPR to 130 MW (and 32.5 MWh of energy storage) during any South Australia islanding event. AEMO is satisfied that these changes are sufficient to address the Stage 1 South Australian region inertia shortfall for secure operating level of inertia, as declared in August 2020.

AEMO has agreed with ElectraNet that the required services for Stage 2 will be made available from 31 July 2021. This declaration extends stage 2 shortfall declaration (as detailed in Table 8) to also cover 2022-23.

2.7 Tasmania outlook

The Tasmania outlook system strength and inertia will continue to rely on the services procured for the 2019 shortfall declaration. AEMO notes that the shortfall will re-emerge when the existing contract concludes, and that updated projections are highlighting the risk of larger and earlier shortfalls than previously declared.

The system strength and inertia outcomes for Tasmania are complex, due to the number of small hydro machines coupled with increasing penetration of inverter-connected (predominantly) wind generation.

Table 10 provides a summary of the possible system strength projections for the Tasmania fault level nodes. The remainder of this section provides commentary on the market and general network outlook for Tasmania, then gives details for system strength and inertia projections.

2.7.1 Inertia and fault level shortfalls in Tasmania

In November 2019, AEMO declared shortfalls for both inertia and system strength in Tasmania[43]. This set out the requirements to maintain the power system security and system standards in Tasmania. These shortfalls have been addressed through TasNetworks entering into a commercial agreement with Hydro Tasmania for the provision of system strength and inertia services, which expires in 2024.

Where the system strength and inertia requirements are not met in Tasmania, it is expected that the agreement with Hydro Tasmania will continue to be utilised out to 2024.

AEMO considers that beyond the end of that agreement, the operation of generation in the market in Tasmania will be insufficient to meet the requirements for system strength and inertia in Tasmania from May 2024.

The updated projections for this 2020 SSI Report are now showing larger shortfall amounts and durations for both system strength and inertia than previously declared for the Tasmanian region in November 2019. Contributing factors for this outcome in the updated projections are the forecast of an increase in Basslink flows from Victoria to Tasmania as more VRE is installed in Victoria, reducing the need for hydro generation from the larger storages to be online as often. AEMO will continue to work with TasNetworks to further explore the modelling outcomes in early 2021, to refine and assess impacts on existing system strength and inertia services, and the shortfall projected from 2024.

As a result, AEMO has assessed that:

- The shortfall declared in 2019 for system strength and inertia may need to be re-declared. AEMO will work with TasNetworks in early 2021 to review and assess impacts of the new projections on the services already procured, and will announce any re-declaration by the end of March 2021.
- The previous shortfall for inertia will re-emerge in Tasmania from May 2024 following the end of the procurement of the existing services. In addition, the previous shortfall for system strength will re-emerge at the fault level nodes of George Town, Burnie, Waddamana and Risdon from May 2024 following the end of the procurement of the existing services.

Burnie fault level node recalculation

In August 2020, TasNetworks wrote to AEMO requesting a review of the requirements for the Burnie fault level node as a result of updated EMT models becoming available for the wind farms in the vicinity of Burnie.

[43] Notice of Inertia and Fault Level Shortfalls in Tasmania, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

Table 9 Updated requirements for Burnie node (MVA)

Condition	2019	Updated 2020
Pre-contingent	750A	850
Post-contingent	600*	560

* Maintaining the post-contingent levels at 600 MVA results in the pre-contingent levels being maintained at over 900 MVA.

Increasing the pre-contingent level from 750 megavolt-amperes (MVA) to 850 MVA is not expected to result in increased operation of system strength services in the area. To maintain the existing post-contingent level of 600 MVA at Burnie, it is necessary to maintain a pre-contingent level of greater than 900 MVA much of the time.

AEMO has reviewed the proposal and is satisfied that amending the levels for the Burnie node to 850 MVA pre-contingent and 560 MVA post-contingent is prudent and not likely to result in instability of plant or generation in the area.

Further information on the assessment methodology for Burnie is available in Appendix A3.3.

2.7.2 Tasmania system strength outlook

The system strength outlook for Tasmania is shown in Table 10. Each node includes information on the fault level node class, relevant duration curves, whether the requirements are met now and at the end of the outlook period, and comments regarding the requirements. Note that no post-contingent level is currently defined for the nodes at George Town, Waddamana and Risdon.

Figure 27 to Figure 30 show that, based on the modelling carried out by AEMO, there will be insufficient units online to meet the minimum requirements for significant periods of time. This does not take account of the system strength and inertia services agreement that TasNetworks has entered into.

For further details regarding the system strength analysis undertaken, please refer to Appendices A2 and A4.

Table 10 Tasmania system strength outlook

Fault level node	Fault level node class	Duration curves	2020 minimum three phase fault level (MVA)		2020 minimum three phase fault level (MVA)		Comments
			Pre-contingency	Post-contingency	Current	Up to 2025-26	
Burnie 110 kV	Remote from synchronous generation	Figure 27	850	560	Yes^	Shortfall of 200 to 300 MVA	Shortfall currently met by commercial agreement for system strength and inertia services.
George Town 220 kV	High IBR	Figure 28	1,450	-	Yes^	Shortfall of 800 to 1,100 MVA	
Risdon 110 kV	Metropolitan load centre	Figure 29	1,330	-	Yes^	Shortfall of 550 to 850 MVA	
Waddamana 220 kV	Synchronous generation centre	Figure 30	1,400	-	Yes^	Shortfall of 600 to 950 MVA	

^ Results in this report highlight the risk of new shortfalls emerging from 2021. AEMO will work with TasNetworks in early 2021 to review and assess impacts on the services previously procured. AEMO will announce whether a new shortfall is declared by end of March 2021.

Figure 27 System strength outlook for Burnie under the traditional operations projections

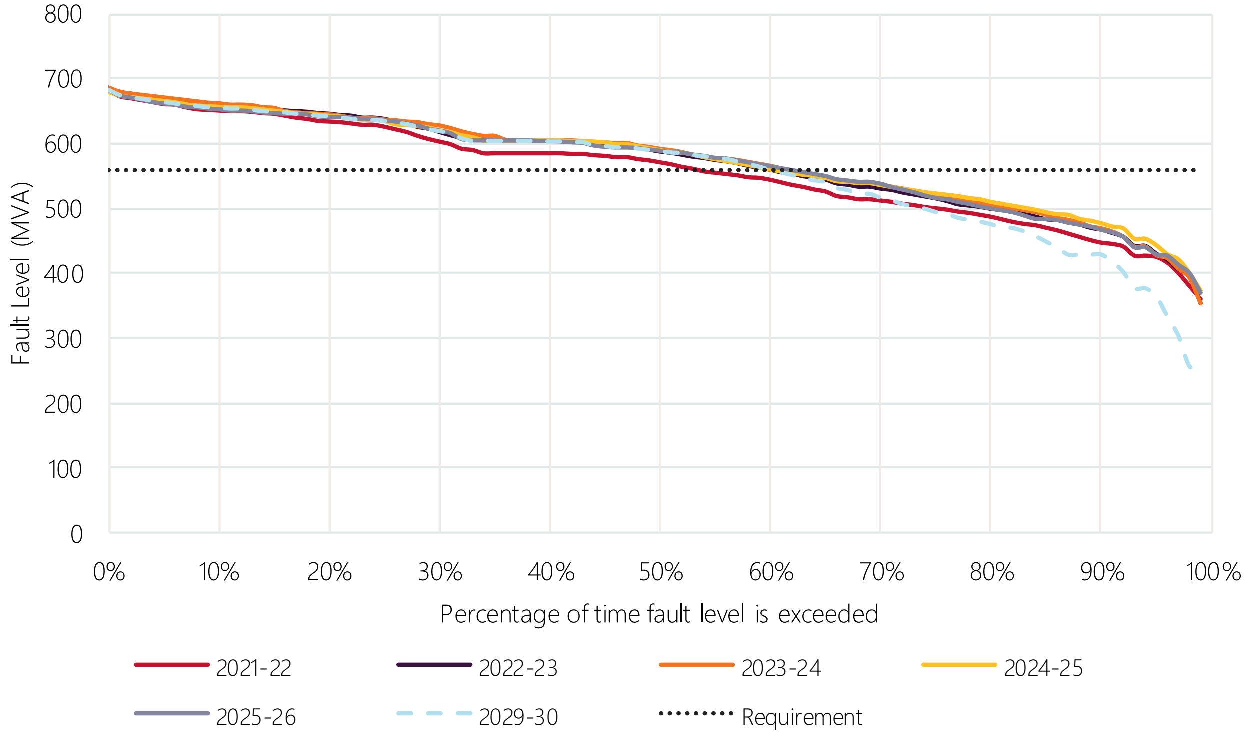


Figure 28 System strength outlook for George Town under the traditional operations projection

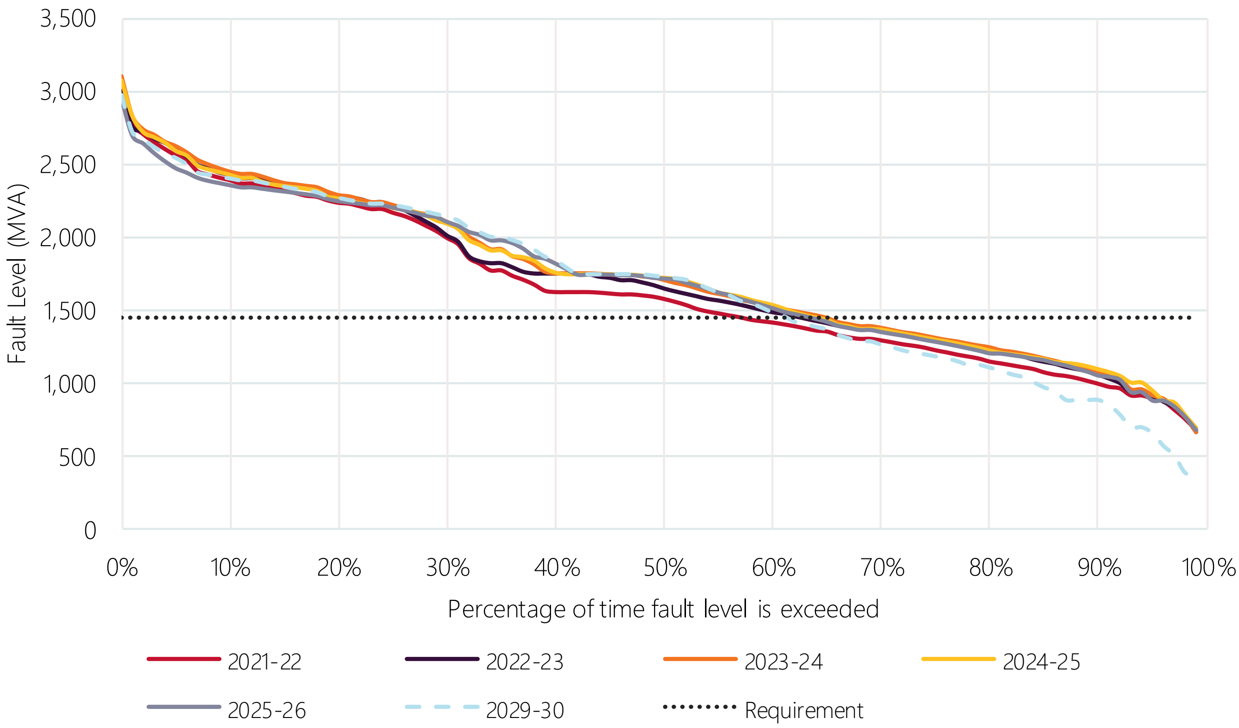


Figure 29 System strength outlook for Risdon under the traditional operations projection

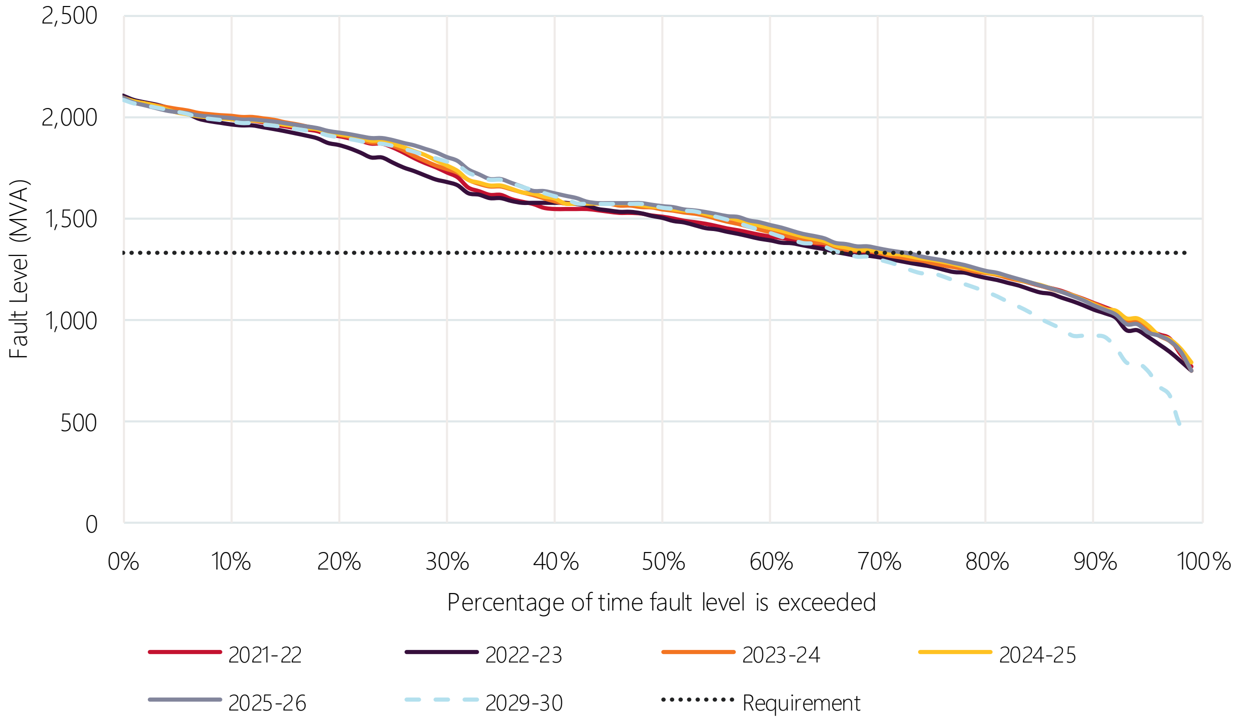
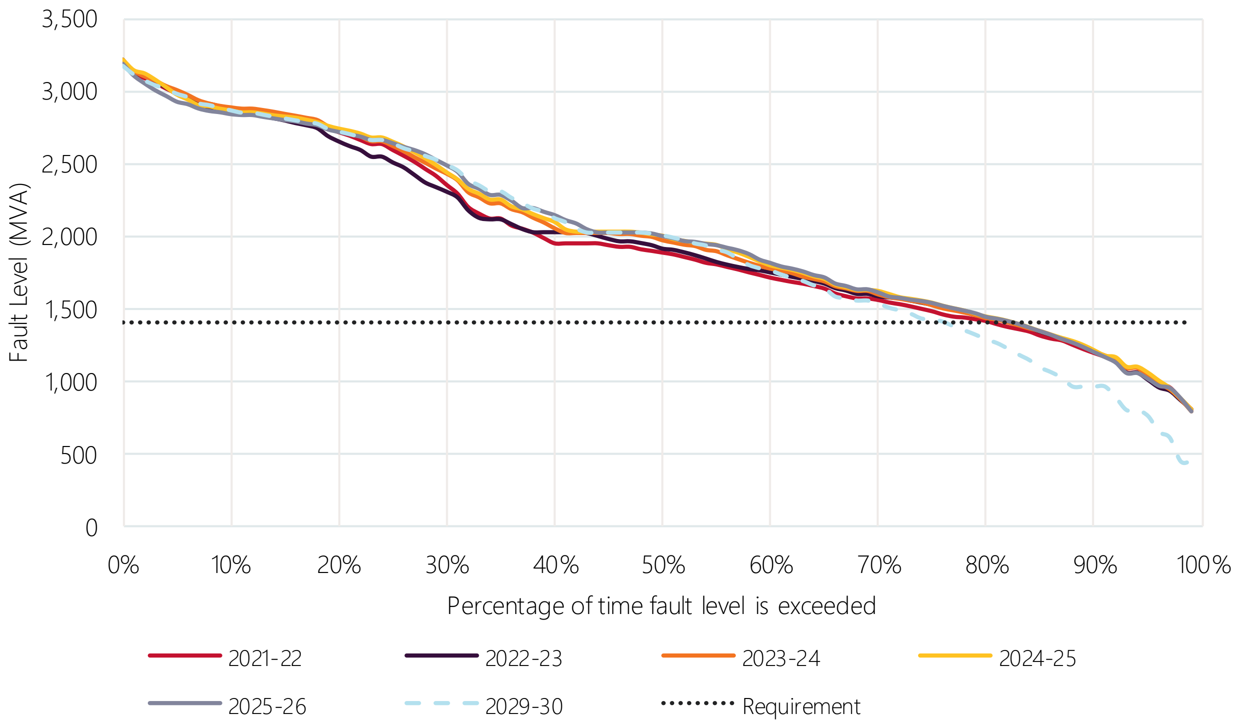


Figure 30 System strength outlook for Waddamana under the traditional operations projection



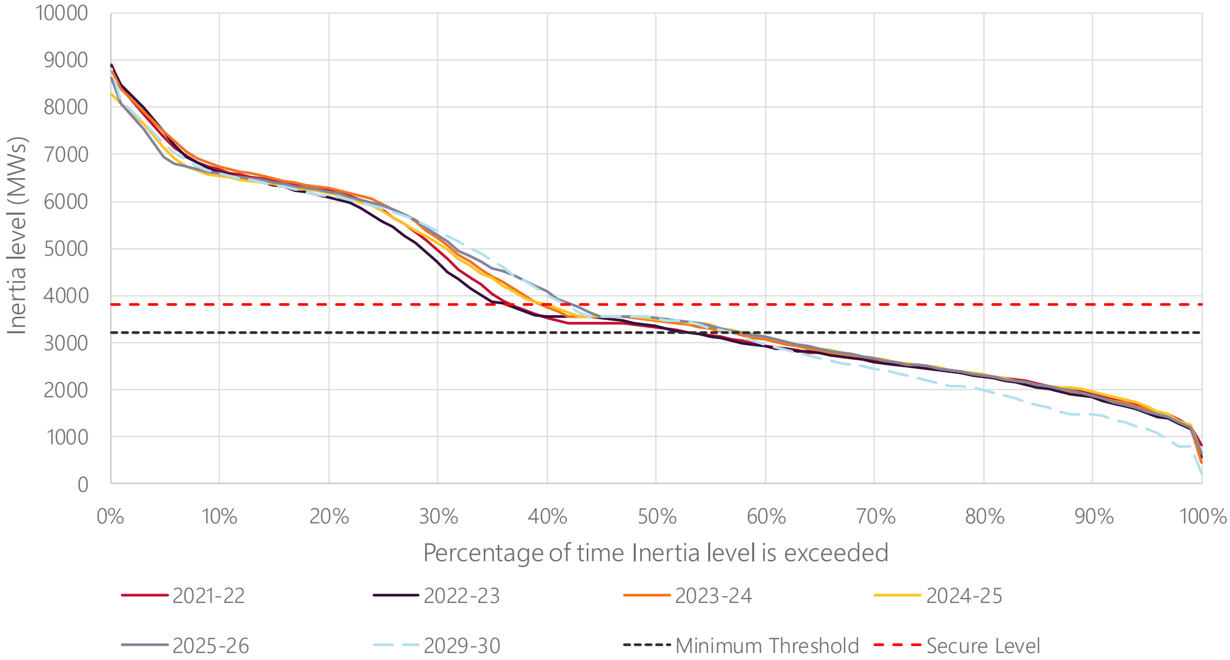
2.7.3 Tasmania inertia outlook

Using the inertia requirements and shortfall projection and assessment methods described in Section A2.2 and Section A.2.4, AEMO has assessed whether there is likely to be an inertia shortfall in the Tasmania region of the NEM, consistent with clause 5.20B.2 of the NER.

AEMO's assessment has been made by using inertia projections derived from the traditional operations and high renewable energy projections as outlined in Section A2.5 to calculate when the expected inertia online will not meet the inertia requirements for more than 99% of the time. In addition, in accordance with the NER requirements, AEMO's assessment includes consideration of the likelihood of islanding. Consistent with AEMO's 2018 Inertia Requirements and Shortfall publication[44], islanding of Tasmania remains non-remote. This finding is due to Tasmania having only a direct current (DC) interconnection to Victoria via Basslink.

Figure 31 shows projected inertia in Tasmania for the five-year outlook under the traditional operations projection, against the minimum threshold level of inertia and the secure operating level of inertia (3,200 MWs and 3,800 MWs respectively).

Figure 31 Inertia outlook for Tasmania under the traditional operations projection



Without continuation of the system strength and inertia services contracts (or other sources of services) for the period to 2025-26, AEMO projects a shortfall in the minimum threshold level of inertia and the secure operating level of inertia in Tasmania. AEMO previously identified a shortfall in inertia of 2,350 MWs in the Notice of Inertia and Fault Level Shortfalls in Tasmania published in November 2019[45], compared to the 2,600 MWs in these updated projections.

As noted in the system strength section above, the updated projections for this 2020 SSI Report are now showing larger shortfall amounts and durations for both system strength and inertia than previously declared for the Tasmanian region in November 2019. AEMO will continue to work with TasNetworks to further explore the modelling outcomes in early 2021, to refine and assess impacts on existing system strength and inertia services, and the shortfall projected from 2024.

[44] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[45] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

For further details regarding the inertia analysis undertaken, please refer to Appendix A5.

Projection for meeting the minimum and secure levels of inertia

AEMO declared an inertia and system strength shortfall for Tasmania in 2019, resulting in TasNetworks contracting Hydro Tasmania to provide inertia network services and system strength services in sufficient quantity to meet the declared shortfall volumes[46]. These services were contracted for four years, and at the expiration of this contract in May 2024, a shortfall of 2,000 MWs is projected for the minimum threshold level of inertia and 2,600 MWs in the secure operating level of inertia. Shortfalls for both the minimum threshold and secure operating levels of inertia are projected for the remainder of the five-year outlook. The projected 99th percentile results are listed in Table 11, which highlights the magnitude of shortfall projected for both minimum threshold and secure operating levels of inertia.

Table 11 Summary of inertia shortfall assessment for Tasmania under traditional operations projection

Inertia (MWs)	2023-24	2024-25	2025-26
Minimum inertia requirement	3,200	3,200	3,200
Secure inertia requirement*	3,800	3,800	3,800
Available 99% of time	1,200	1,200	1,200
Shortfall minimum threshold level of inertia	2,000	2,000	2,000
Shortfall secure operating level of inertia	2,600	2,600	2,600

* 3,800 MWs is the secure operating level of inertia assuming a loss of the largest hydro generation unit in Tasmania.

At all times, the inertia required to meet the secure operating level of inertia (3,800 MWs) must only be sourced from within the Tasmania region. This requirement arises because AEMO always considers Tasmania an electrical island with respect to the NEM due to Tasmania having only a sole DC interconnection (Basslink) to the NEM. While the Basslink interconnector does provide frequency control, it does not transport synchronous inertia in the same way that an AC link does. In effect this means Tasmania is always operated as an island with respect to inertia.

2.8 Victoria outlook

The system strength shortfall identified at Red Cliffs in Victoria has been met until at least 2022 by AEMO (as the Victorian system strength service provider) procuring system strength services in the local area. Analysis is underway to confirm the scale of the system strength shortfall at the Red Cliffs node beyond 2022.

No other system strength or inertia shortfalls are currently projected for Victoria in the next five years, but shortfall risks are increasing. There is growing evidence that changes in operation of major power stations may lead to system strength shortfalls in the centre of the state. AEMO will analyse future system strength and inertia requirements and support the transition of the Victorian energy system.

The system strength and inertia outcomes for Victoria are heavily influenced by the reduction in the number of coal-fired machines online when considering the high renewables projection.

[46] TasNetworks, Annual Planning Report 2020, at https://www.tasnetworks.com.au/config/getattachment/4a3679b2-d65a-4c8e-b2f6-34920dbb2045/tasnetworks-annual-planning-report-2020.pdf.

In the case of system strength, reduction in the number of units online due to withdrawal of units or flexible operation would be expected to lead to system strength shortfalls at Thomastown, Hazelwood and Moorabool for the Victoria region after 2025-26. In the case of inertia, AEMO has assessed the risk of electrical islanding of the Victoria region as unlikely, meaning no shortfall is declared.

The timing, magnitude and likelihood of additional system strength shortfalls for Victoria is uncertain. Before AEMO can form an assessment that a shortfall is reasonably likely, as required by the NER, more work is required to increase:

- Technical certainty about the size and scale of the potential shortfalls and their solutions. More detailed steady state and EMT analysis is required to understand the potential shortfalls, and allocation of appropriate future fault level nodes as the power system transitions.
- Certainty around imminent withdrawal of synchronous generating units from the market at times of low demand. As more renewable generation is commissioned, there is growing evidence that synchronous generators are decommitting more often and operating more flexibly, reducing provision of system services. The Victorian government's newly announced policies to support a number of REZs across the state[47] is intended to accelerate the introduction of new renewable generation.

In December 2019, AEMO declared a fault level shortfall at Red Cliffs which required that system strength services be in place to address the shortfall by 1 January 2021. On 6 August 2020, AEMO issued a notice of change to the system strength requirement and shortfall at Red Cliffs[48]. At that time AEMO assessed the post-contingency minimum fault level requirement at Red Cliffs as 1,000 MVA, subject to operating conditions, and in its role as System Strength Service Provider for the Victorian region AEMO secured sufficient services from facilities in the West Murray area to meet the assessed requirement for two years from August 2020. This 2020 SSI Report provides more detail about the changes underlying the updated minimum fault level requirement, and analysis is underway to confirm the scale of the shortfall beyond 2022.

AEMO will continue to work with stakeholders on the Victorian system strength and inertia outcomes. This includes considering new information as it becomes available, updating assessments and providing notices as necessary.

The remainder of this section provides an update to the Red Cliffs minimum fault level requirement and fault level shortfall, provides commentary on the market and general network outlook for Victoria, and gives details for system strength and inertia projections.

2.8.1 Update to the Red Cliffs minimum fault level requirement and fault level shortfall

In December 2019, AEMO declared a fault level shortfall at Red Cliffs which required that system strength services be in place to address the shortfall by 1 January 2021. AEMO is the System Strength Service Provider for the Victorian region.

In August 2020, AEMO issued a notice of change to the system strength requirement at Red Cliffs[49], with the post-contingency minimum fault level requirement at Red Cliffs being assessed as 1,000 MVA, subject to operating conditions. This assessment incorporated the impact of changes to the expected operation of existing and new power system equipment on the determination of system strength requirements, including:

- Revision of the number of online synchronous generation units assumed to be needed in Victoria (more details are available in Appendix A3).

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[47] See https://www.premier.vic.gov.au/backing-new-energy-breakthroughs-and-victorian-jobs.

[48] AEMO, Notice of change to system strength requirement and shortfall at Red Cliffs, 6 August 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en&hash=5C3EDDABDF81891B3989F6FF0466C486.

[49] AEMO, Notice of change to system strength requirement and shortfall at Red Cliffs, 6 August 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/notice-of-change-to-red-cliffs-220kv-minimum-fault-level-requirement-and-shortfall.pdf?la=en&hash=5C3EDDABDF81891B3989F6FF0466C486.

- Revisions to detailed model information for a number of inverter-based generators in the broader West Murray region, reflecting changes including retuning of five previously constrained generating systems successfully completed in April 2020[50].
- Accounting for system strength remediation schemes agreed with newly connecting generators.

Additional information on the inputs, assumptions and methodology for the calculation of the Red Cliffs minimum fault level requirement is provided in Appendix A3.2.

AEMO secured sufficient services from facilities in the West Murray area (spanning north-west Victoria and south-west New South Wales) to address the assessed fault level shortfall, effective for two years from August 2020.

As shown in Figure 36, the projected fault levels at the Red Cliffs node indicate this shortfall will continue beyond August 2022 until the completion of the proposed Project EnergyConnect network upgrade. As Project EnergyConnect is not a committed project, however, the duration of the fault level shortfall remains uncertain. Further information on Project EnergyConnect can be found in Section A2.8.

AEMO has conducted an expression of interest process for a longer-term system strength solution[51] to this shortfall.

Analysis is ongoing to confirm the scale of the system strength shortfall at Red Cliffs beyond 2022.

Further studies are underway to validate the minimum fault level requirement for Red Cliffs.

2.8.2 Victoria market and network outlook

Market modelling projects that the annual cumulative ramping requirements from Victoria's brown coal-fired generation fleet will increase beyond ramping observed in recent history[52]. While this forecast ramping behaviour is within the bounds of the technical limitations of the Victorian units, it may place further strain on the ageing brown coal-fired generation fleet which has historically operated predominantly as a baseload technology.

Ramping requirements are also exacerbated by AEMO's latest minimum demand projections, which outline a faster decline relative to previous AEMO forecasts, this trend combined with the large amount of renewables uptake in the high renewable energy projection could challenge traditional operating regimes in the short to medium term.

Latrobe Valley coal generation retirement implications for Melbourne region

The number of units projected to be online in the Latrobe Valley area reduces by 2030-31 in the high renewable energy projection. The resultant change in generation would result in reduction in flows over the Latrobe Valley to Rowville 220 kV networks, and increased loading on the 500 kV network would also increase loading on 500/220 kV and 330/220 kV transformers in the Greater Melbourne area under high demand conditions.

Figure 32 shows the number of synchronous units dispatched in Victoria under traditional operation and flexible operation sensitivities. The acceptable minimum synchronous machine combination is also shown.

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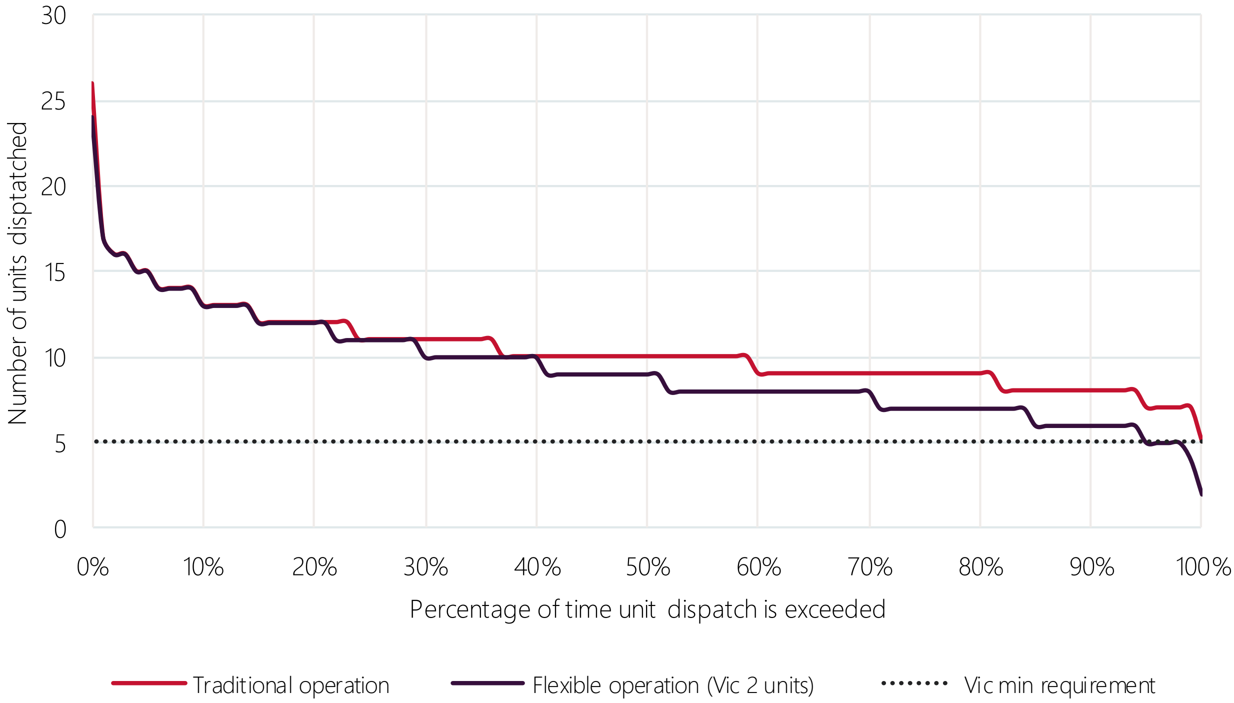
[50] AEMO, Market Notice 75470, UPDATE: Maintain the power system in a secure operating state in the Victoria and New South Wales regions.

[51] At https://aemo.com.au/consultations/tenders/victorian-transmission/call-for-expressions-of-interest-victorian-system-strength.

[52] For more details, see Appendix A2.5 of this report, and Appendix 5. Future Power System Operability of the 2020 ISP, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

Figure 32 Number of synchronous machines dispatched in Victoria



Possible augmentations to reinforce supply to Greater Melbourne area

Possible solutions to reinforce supply to Greater Melbourne area could combine network re-configuration, new transmission elements, or non-network solutions. Detailed cost benefit assessment of network and non-network options would identify staging of reinforcement and take into account any system strength or inertia mitigation.

2.8.3 Victoria system strength outlook

The system strength outlook for Victoria is shown in Table 12. Each node includes information on the fault level node class, relevant duration curves, whether the requirements are met now and at the end of the outlook period, and comments regarding the requirements.

The results in Figure 33 to Figure 37 show that no new shortfalls are expected to occur in Victoria in the five-year outlook period to 2025-26. The previously declared shortfall at Red Cliffs will, without extension of existing services, continue until the commissioning of the proposed Project EnergyConnect, subject to ongoing analysis to confirm the scale of the system strength shortfall at Red Cliffs beyond 2022.

For further details regarding the system strength analysis undertaken, please refer to Appendices A3 and A4.

Table 12 Victoria system strength outlook

Fault level node	Fault level node class	Duration curves	2020 minimum three phase fault level (MVA)		Requirements met		Comments
			Pre-contingency	Post-contingency	Current	Up to 2025-26	
Dederang 220 kV	• Remote from synchronous generation	Figure 33	3,500	3,300	Yes	Yes	
Hazelwood 500 kV	• Synchronous generation centre. • Close to Basslink DC link.	Figure 34	7,700	7,150	Yes	Yes	
Moorabool 220 kV	• High IBR	Figure 35	4,600	4,050	Yes	Yes	
Red Cliffs 220 kV	• High IBR • Remote from synchronous generation	Figure 36	1,700	1,000	Yes^	Yes, subject to validation^	^Refer to Section 2.8.1 for more details on the Red Cliffs node
Thomastown 220 kV	• Metropolitan load centre	Figure 37	4,700	4,500	Yes	Yes	

Figure 33 System strength outlook for Dederang under the high renewable projection

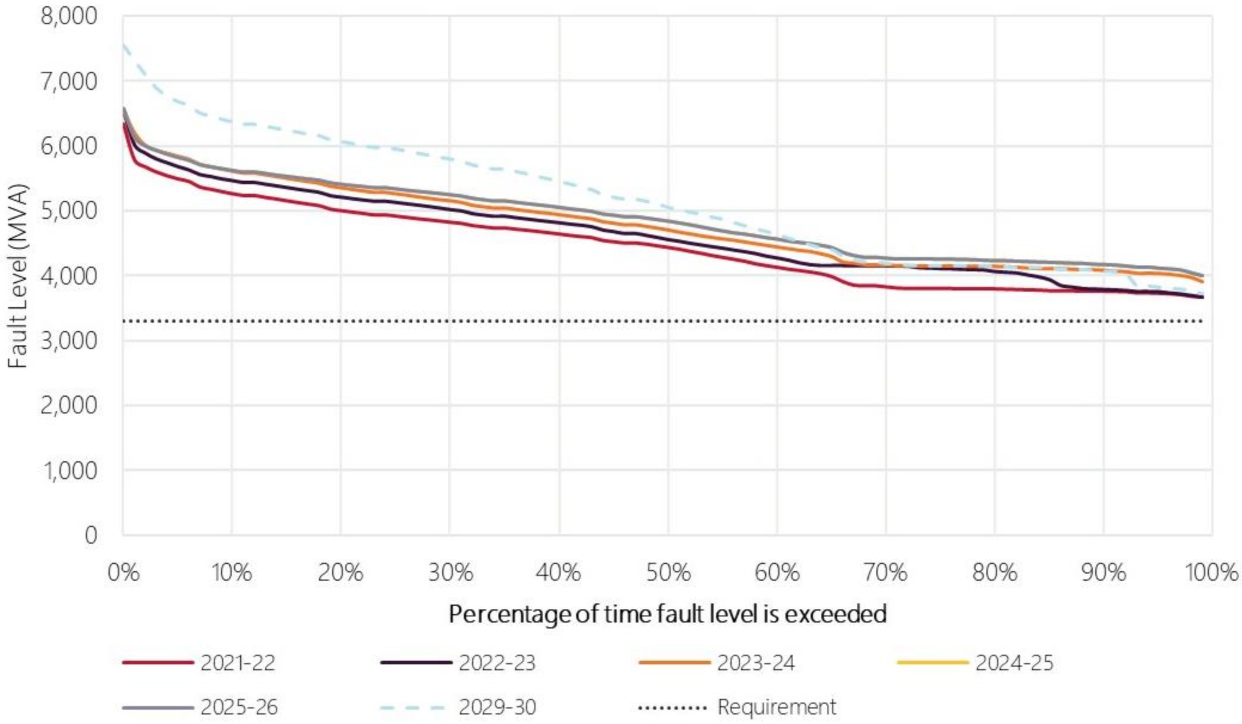


Figure 34 System strength outlook for Hazelwood under the high renewable projection

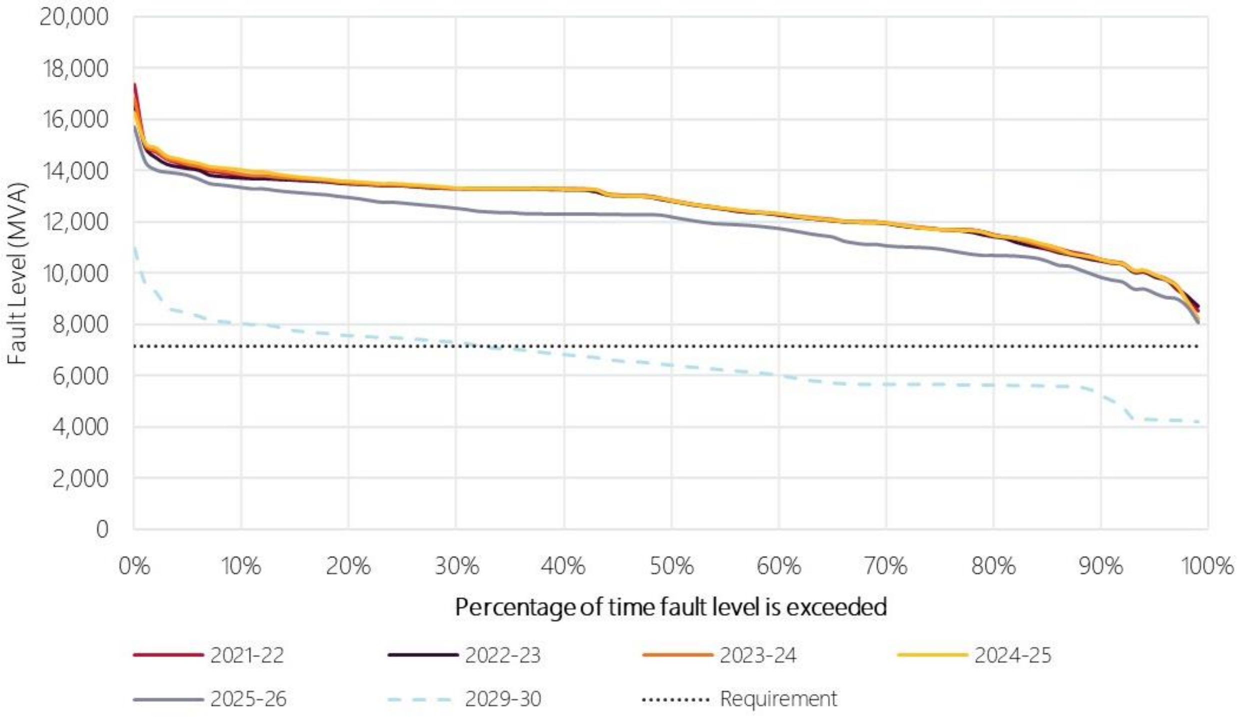


Figure 35 System strength outlook for Moorabool under the high renewable projection

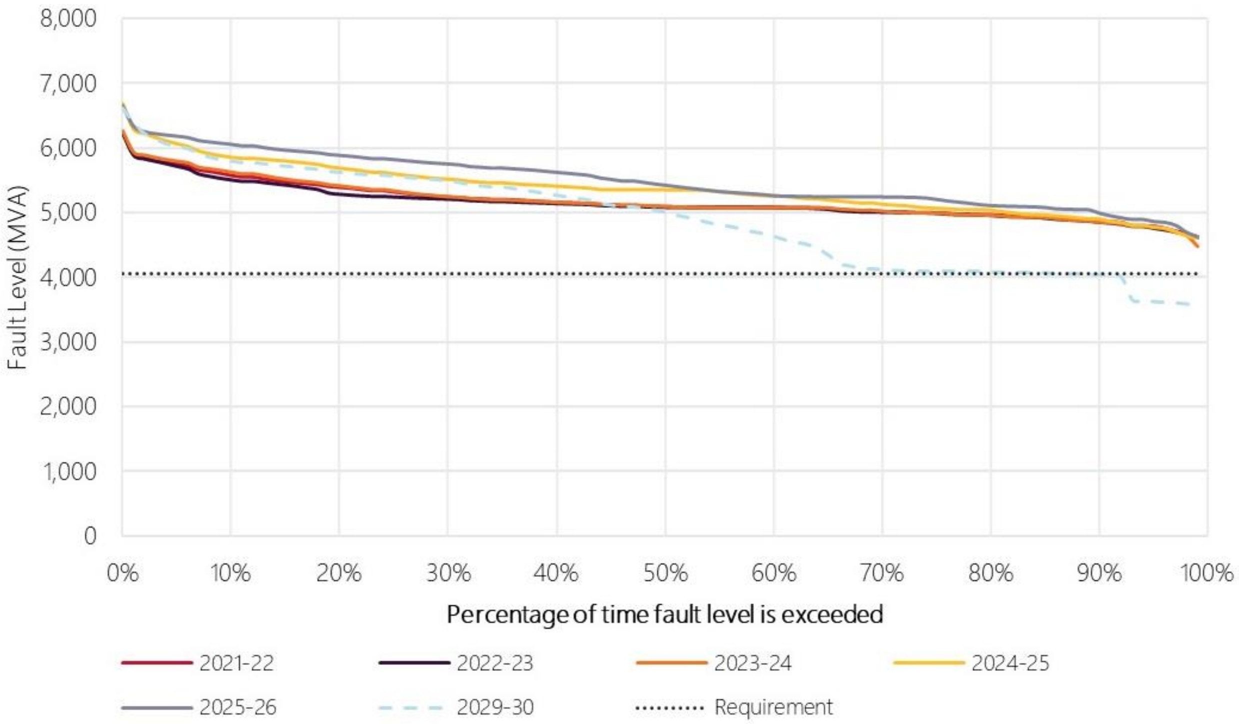


Figure 36 System strength outlook for Red Cliffs under the high renewable projection

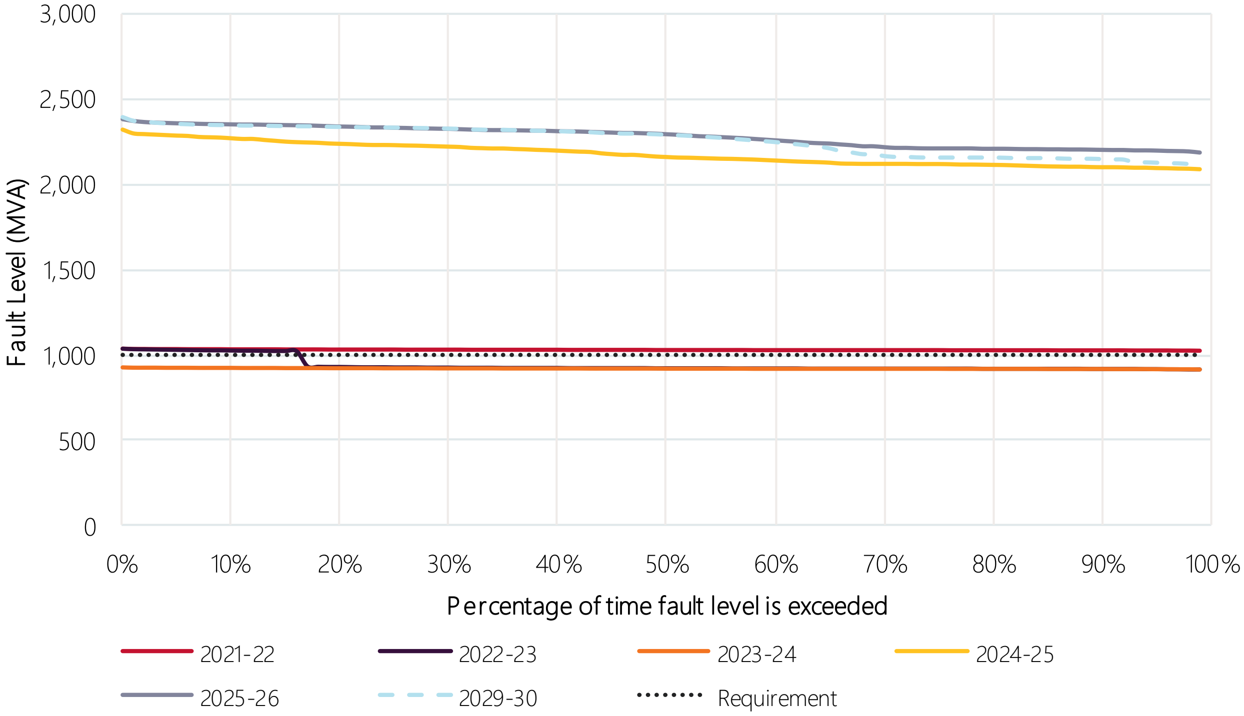
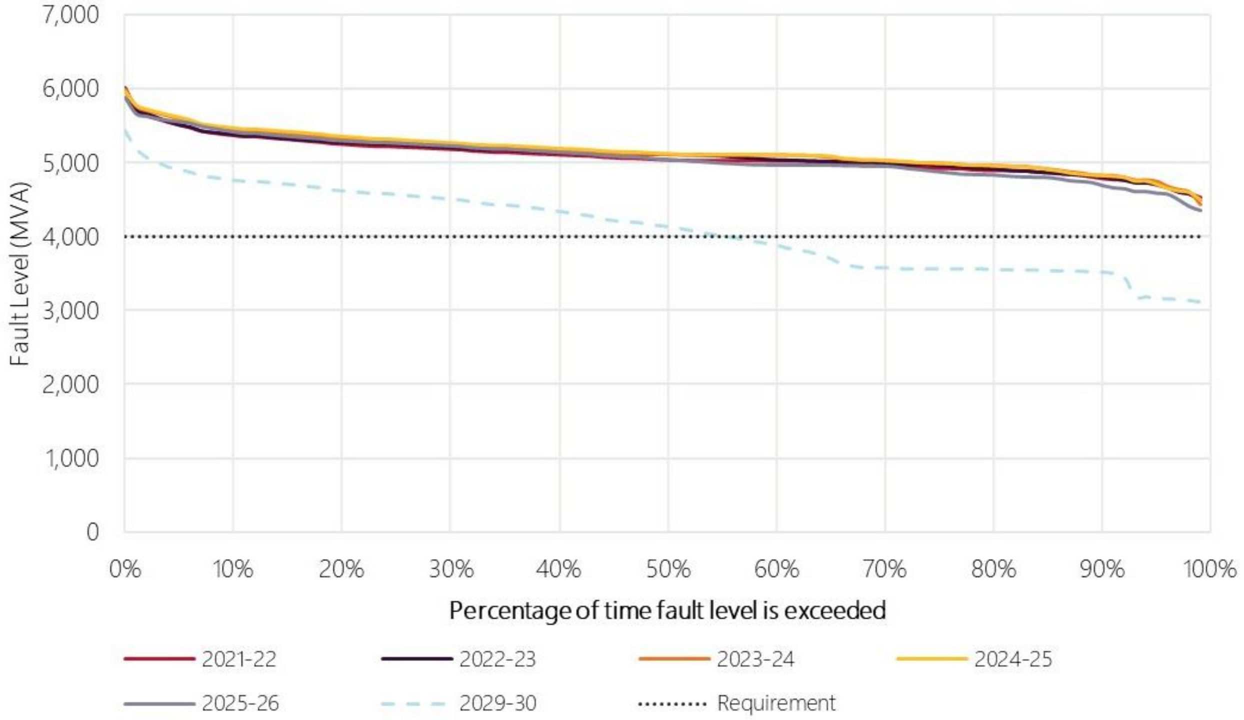


Figure 36 shows that the current system strength mitigation measures in place until August 2022 are sufficient to meet the fault level requirements for Red Cliffs until that time. Analysis is underway to confirm the scale of the system strength shortfall at Red Cliffs beyond 2022 and prior to the commissioning of Project EnergyConnect.

Figure 37 System strength outlook for Thomastown under high the renewable projection

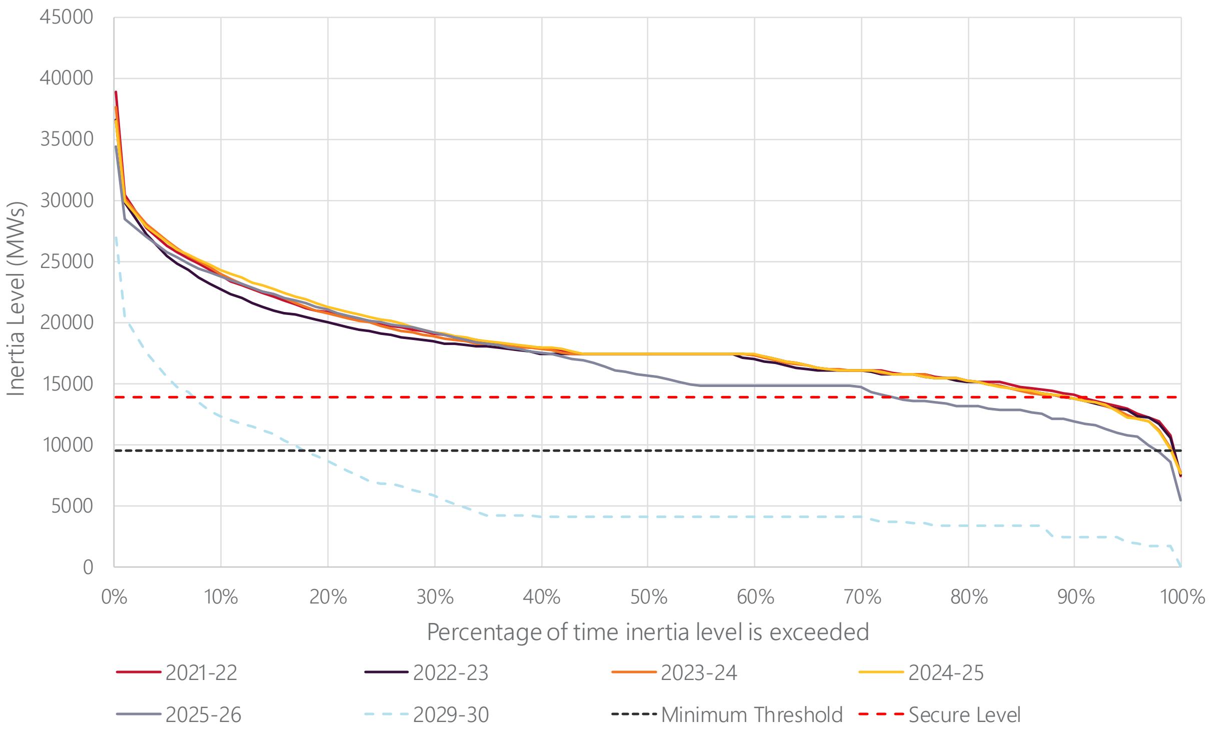


2.8.4 Victoria inertia outlook

Using the inertia requirements and the shortfall projection and assessment methods described in Section A2.2 and Section A2.4, AEMO has assessed whether there is likely to be an inertia shortfall in the Victoria region of the NEM, consistent with clause 5.20B.2 of the NER. AEMO's assessment has been made by using inertia projections derived from the traditional operations and high renewable energy uptake projections as outlined in Section A2.5 to calculate when the expected inertia online will not meet the inertia requirements for more than 99% of the time. In addition, in accordance with the NER requirements, AEMO's assessment includes consideration of the likelihood of islanding. Consistent with AEMO's 2018 Inertia Requirements and Shortfall publication[53], the likelihood of islanding of Victoria remains remote. This finding is largely driven by the diversity and number of AC interconnectors that exist between Victoria and the adjacent regions.

Figure 38 shows the projected inertia in Victoria for the five-year outlook under the high renewable energy uptake projection, against the minimum threshold level of inertia and the secure operating level of inertia (9,500 MWs and 13,900 MWs respectively). For the period to 2025-26 and beyond, AEMO projects a shortfall in both the minimum threshold level of inertia and the secure operating level of inertia. However, as the likelihood of islanding is remote, no shortfall is declared for Victoria.

Figure 38 Inertia outlook for Victoria under the high renewable projection



Inclusion of the FFR services provided by the planned 300 MW Moorabool battery[54] has been modelled from 2022 onwards. Allowance for this project ensures the secure operating level of inertia remains unchanged for the five-year outlook. In the absence of this project, the secure operating level of inertia requirement almost doubles (24,000 MWs without Moorabool battery)[55]. This demonstrates the significant role FFR services can play in offsetting synchronous inertia requirements and potential shortfalls for a region.

For further details regarding the inertia analysis undertaken, please refer to Appendix A5.

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53 See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

54 NEOEN, News, Nov 2020, at https://www.neoen.com/var/fichiers/20201104-neoen-mr-vbb-announcement.pdf.

55 The doubling of the secure operating level of inertia with the Moorabool battery modelled assumes the distributed PV contingency remains constant from 2022 (see Section A2.2).

3. Next steps

The operability of the NEM over the next decade is expected to become increasingly complex, especially during periods of minimum demand. Coupled with the increasing uptake of IBR across the NEM, system strength and inertia from online machines is anticipated to reduce.

The NER place the responsibility to procure services to address shortfalls in system strength and inertia on the local Service Provider, subject to AEMO determining the requirements and declaring a shortfall. This report constitutes AEMO's notice of these assessments and formal declaration of shortfalls under the NER.

Extension of South Australia inertia shortfall

ElectraNet is the Inertia Service Provider in South Australia. AEMO previously requested ElectraNet to make available inertia services, in two separate stages, to address a forecast shortfall in the secure operating level of inertia up to 2021-22. This declaration extends the requirement for the stage 2 services (as detailed in Table 8) to now include 2022-23.

Re-emergence of Tasmania system strength and inertia shortfall at end of existing contract, and potentially earlier

TasNetworks is the Inertia and System Strength Service Provider in Tasmania. AEMO previously requested TasNetworks make available system strength and inertia services to address identified shortfalls. Updated projections now show larger shortfalls than previously projected, and AEMO will work in collaboration with TasNetworks to further review and understand the modelling outcomes, and the impact on the requirements on the existing system strength and inertia contracted services with any new shortfall declaration to be declared by the end March 2021. In addition, with the existing contract to expire in May 2024, AEMO requests that TasNetworks make available System Strength and Inertia services (as detailed in Sections 2.7.2 and 2.5.3 and Tables 10 and 11), by 31 May 2024.

Red Cliffs system strength shortfall

AEMO, in its role as the Jurisdictional Planning Body, is the System Strength Service Provider for the Victorian region and has delivered services to address the fault level shortfall declared at Red Cliffs in 2019. At present, assessment of the requirements at Red Cliffs for the period post-August 2022 is ongoing.

Ross system strength shortfall

Powerlink is continuing with studies to confirm its proposed solution to address the system strength shortfall declared in April 2020 for the Ross fault level node in Queensland. Powerlink is required to make services available by August 2021.

Future assessments

This assessment found the risk of shortfalls in system strength was increasing but shortfalls are not yet declared for New South Wales, Victoria and Queensland, as they were not yet considered likely. Similarly, there is increasing risk of an inertia shortfall in Queensland, but a shortfall is not yet declared due to uncertainty. Apart from those mentioned above, no declaration has been made for these regions, due to a combination of technical uncertainty surrounding the scale of potential shortfalls and uncertainty regarding changing operation of synchronous generating units at times of minimum demand.

AEMO will continue to work with the respective network service providers and market participants to assess the requirement for these regions, and may declare shortfalls ahead of the publication of the 2021 System Strength and Inertia Report/s.

Potential regulatory changes

In parallel to the assessments completed for this SSI Report, the market institutions are considering major changes to the regulatory frameworks governing the operability and security of the power system.

The Australian Energy Market Commission's (AEMC's) system strength frameworks review[56] was completed in October 2020. The AEMC recommended measures to evolve the existing system strength framework, including introduction of a standard against which TNSPs, working with AEMO, would need to provide system strength to meet both system security needs and to facilitate the connection of new IBR. The recommendations from this review are being developed further through the 'efficient management of system strength on the power system' rule change process[57], which is one of the ongoing synchronous services rule changes[58].

The Energy Security Board's (ESB's) post-2025 NEM market design work program is also considering system strength as part of its essential system services initiative which is intended to develop a reform path for maintaining the NEM in a secure, resilient state. The September 2020 consultation paper for the work program[59] considers a range of options for procuring services, ranging from real-time markets to structured procurements, with a focus on structured procurements for system strength services.

AEMO is working with the other market institutions on these regulatory reviews. AEMO considers it important to ensure that any changes to the regulatory frameworks acknowledge the degree of uncertainty affecting assessment of system strength requirements in the NEM, as noted in this report, as well as ensuring that changes to the frameworks include consideration of efficient outcomes for electricity consumers.

Further feedback and consultation

AEMO welcomes feedback on the material provided in this report, and any related matters, no later than two months from the date of publication. Feedback should be provided to **planning@aemo.com.au**.

[56] AEMC, Investigation into system strength frameworks in the NEM, Final report, 15 October 2020 at https://www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem.

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

[58] AEMC, Consultation begins on new ways to deliver system services as the power system evolves, at https://www.aemc.gov.au/news-centre/media-releases/consultation-begins-new-ways-deliver-system-services-power-system.

[59] See https://esb-post2025-market-design.aemc.gov.au/32572/1599208730-final-p2025-market-design-consultation-paper.pdf.

A1. Summary of shortfall projections

Table 13 is a summary of the system strength and inertia shortfalls identified in the traditional operations and high renewable energy projections, and the high renewable with flexible operation sensitivities.

System strength is the comparison of the post-contingency fault level against the post-contingency requirement for each node, calculated in MVA. Inertia is the projection of online inertia against the secure operating level of inertia, calculated in MWs.

Table 13 Summary of possible system strength and inertia shortfalls assessments under different projections

Region / Node	Measure	Traditional Operations					High Renewable Energy					+ Flexible operation	Notes
		2021-22	2022-23	2023-24	2024-25	2025-26	2021-22	2022-23	2023-24	2024-25	2025-26	2025-26	
New South Wales	SOLI (MWs)	-	-	-	-	-	-	-	-	-	-	-	
Armidale 330 kV	Fault level (MVA)	-	-	-	-	-	-	-	-	-	-	-	
Wellington 330 kV		-	-	-	-	-	-	-	-	-	-	-	
Newcastle 330 kV		-	-	-	-	-	-	-	-	-	450	1,600	Note 1
Sydney West 330 kV		-	-	-	-	-	-	-	-	-	250	1,150	Note 2
Darlington Point 330 kV		-	-	-	-	-	-	-	-	-	-	-	
Queensland	SOLI (MWs)	-	-	-	-	-	-	-	-	-	400	2,600	Note 3
Ross 275 kV	Fault level (MVA)	Note 4	Note 4	Note 4	Note 4	Note 4	Note 4	Note 4	Note 4	Note 4	Note 4	Note 4	
Gin Gin 275 kV		-	-	-	-	-	-	-	-	50	50	50	Note 3
Lilyvale 132 kV		-	-	-	-	-	-	-	-	-	-	-	
Greenbank 275 kV		-	-	-	-	-	-	-	-	-	-	-	
Western Downs 275 kV		-	-	-	-	-	-	-	-	-	25	25	Note 3

Region / Node	Measure	Traditional Operations					High Renewable Energy					+ Flexible operation	Notes
		2021-22	2022-23	2023-24	2024-25	2025-26	2021-22	2022-23	2023-24	2024-25	2025-26	2025-26	
South Australia	**SOLI (MWs)**	Note 5	Note 5	Note 5	Note 5	Note 5	Note 5	Note 5	Note 5	Note 5	Note 5	Note 6	
Davenport 275kV	**Fault level (MVA)**	Solution	-	-	-	-	Solution	-	-	-	-	Note 6	
Robertstown 275 kV		Solution	-	-	-	-	Solution	-	-	-	-	Note 6	
Para 275 kV		Solution	-	-	-	-	Solution	-	-	-	-	Note 6	
Tasmania	**SOLI (MWs)**	Note 7	Note 7	2,600	2,600	2,600	Note 7	Note 7	2,600	2,900	3,000	Note 6	
George Town 220 kV	**Fault level (MVA)**	Note 7	Note 7	550	500	550	Note 7	Note 7	950	1,000	1,000	Note 6	
Burnie 110 kV		Note 7	Note 7	200	200	200	Note 7	Note 7	250	300	300	Note 6	
Waddamana 220 kV		Note 7	Note 7	600	600	600	Note 7	Note 7	850	950	950	Note 6	
Risdon 110 kV		Note 7	Note 7	550	500	550	Note 7	Note 7	700	800	800	Note 6	
Victoria	**SOLI (MWs)**	2,100	2,600	3,200	3,300	3,300	3,100	3,400	4,200	4,300	5,400	5,400	
Red Cliffs 220 kV	**Fault level (MVA)**	-	-	100	100	-	-	-	100	100	-	-	Note 8
Dederang 220 kV		-	-	-	-	-	-	-	-	-	-	-	
Hazelwood 500 kV		-	-	-	-	-	-	-	-	-	-	-	
Thomastown 220 kV		-	-	-	-	-	-	-	-	-	-	-	
Moorabool 220 kV		-	-	-	-	-	-	-	-	-	-	-	

Notes

1. Unit withdrawal sensitivity, considering 2 units each in Victoria, New South Wales and Queensland.
2. Unit withdrawal sensitivity, considering only 2 units in Victoria.
3. Intra-day decommitment sensitivity, considering 4 units in Queensland and 2 units in New South Wales.
4. The shortfall at Ross is under review. Refer to Section 2.5.1.
5. The Secure Operating Level of Inertia for South Australia is dependent on the amount of FFR available. Refer to Section 2.6.3.
6. Flexible operations sensitivities were considered for units in Queensland, New South Wales and Victoria only, and do not impact the minimums in South Australia and Tasmania.
7. Results in this report highlight the risk of new shortfalls emerging from 2021. AEMO will work with TasNetworks in early 2021 to review and assess impacts on the services previously procured.
8. The shortfall at Red Cliffs after the end of the existing system strength contract and prior to the commissioning of Project EnergyConnect is subject to ongoing analysis. Refer to Section 2.8.1.

A2. Assessment methods and assumptions

This 2020 SSI Report has been prepared by:

- Assessing the requirements for each region.
- Projecting the available system strength and inertia for the next five years, using market assessment and power system analysis.
- Identifying any shortfalls between the requirements and the projections.

Supporting analysis has been completed to understand the broader power system implications of the changing market in addition to consideration of system strength and inertia.

This section provides the methods and inputs used to complete the assessment:

- Sections A2.1 and A2.2 describe the assessment of system strength and inertia requirements.
- Sections A2.3 and A2.4 explain the process applied to project available system strength and inertia and determine shortfalls.
- Section A2.5 outlines the market modelling methodology and assumptions for this report as well as noting prevailing market conditions and projections.
- Section A2.6 lists the future electricity demand assumptions applied. The factors impacting future electricity generation are noted in Section A2.7.
- Section A2.8 records the major transmission network upgrade projects assumed in this report.

A2.1 Assessment of system strength requirements

AEMO applies the System Strength Requirements Methodology[60] to determine the system strength requirements for each region of the NEM by selecting fault level nodes and then assessing the minimum three phase fault level required at each node.

The requirements are prepared assuming normal operating conditions. These requirements do not necessarily have to be met at all times operationally, for example under reduced IBR output conditions, or for planned outages of network elements, providing that system security can still be maintained.

The requirements take into account the stability of the region following any credible contingency event or protected event when determining system strength requirements.

The requirements consider the system strength services which must be made available by TNSPs but exclude the system strength remediation which must be delivered by new or modified generation connections.

The system strength assessment methods are described at a high level in this section, as well as key assumptions. This report includes a combination of new determinations of requirements as well as noting requirements made previously for some regions, with the comprehensive list of current system strength requirements summarised in Section 3.1. Appendix A2 provides details of the model setup for the EMT analysis, and Appendix A4 provides details of the model setup for the steady state fault level analysis.

[60] AEMO, System Strength Requirements Methodology, July 2018, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

Selection of fault level nodes

AEMO must select points in the electricity network to be 'fault level nodes' where minimum levels of system strength need to be maintained for each region[61]. Figure 39 notes the four categories of fault level nodes and their properties. AEMO, in consultation with the relevant TNSP or jurisdictional planning body, selects at least one fault level node from each category for each region of the NEM to ensure holistic representation of system strength needs.

AEMO may reallocate fault level nodes over time as the electricity system transforms. For example, in April 2020, AEMO substituted the Nebo node[62] in Queensland with the Ross node. The Ross 275 kV bus is in an area with high levels of inverter-connected generation, and is electrically remote from large synchronous generation in South and Central Queensland but close to the gas-fired and hydro-powered generation in North Queensland, so it was determined that the fault level at the Ross 275 kV bus better represented the system strength conditions in North Queensland than the more southerly Nebo 275 kV bus.

Figure 39 Categories of fault level nodes

Metropolitan load centres	Synchronous generation centres	High inverter-based resource penetration	Electrically remote from synchronous generation
• High load concentrations • Impact on stabilising reactive plant • Changing consumer patterns (distributed PV)	• Represent net fault levels from traditional generation • Early warning of potential system strength issues in the region	• Instability issues • Sharing of fault level across many individual resources	• Inherently low system strength • May also have high inverter-based resource penetration

Determination of minimum three phase fault level requirements

AEMO takes three main steps to determine the minimum three phase fault level requirements at each fault level node, as explained in the System Strength Requirements Methodology[63] and summarised in Figure 40[64]:

- Given the importance of fault level contribution from synchronous generators and synchronous condensers for overall system strength, the first step is to determine the minimum synchronous machine dispatch conditions needed to satisfy power system stability criteria in each region[65].
- The second step is to assess the fault level requirements in each region using these minimum combinations.
- The final step is to analyse any resultant short-term power system stability issues in close detail. The final step often requires modelling of potential solutions to meet any shortfalls in order to fully understand the nature of the problem and the benefit of possible solutions. Often the final step is only studied in detail for nodes where stability issues are seen, in order to quantify shortfalls. For other nodes, using minimum synchronous machine combinations can result in fault level requirements that are not strictly the absolute

[61] NER Clause 5.20C.1

[62] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-queensland-system-strength-requirements-and-ross-node-fault-level-shortfall.pdf?la=en#:~:text=Fault%20levels%20at%20Ross%20are,operation%20of%20inverter%2Dconnected%20resources.

[63] Full detail on the calculation method can be found in AEMO's System Strength Requirements Methodology, July 2018, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

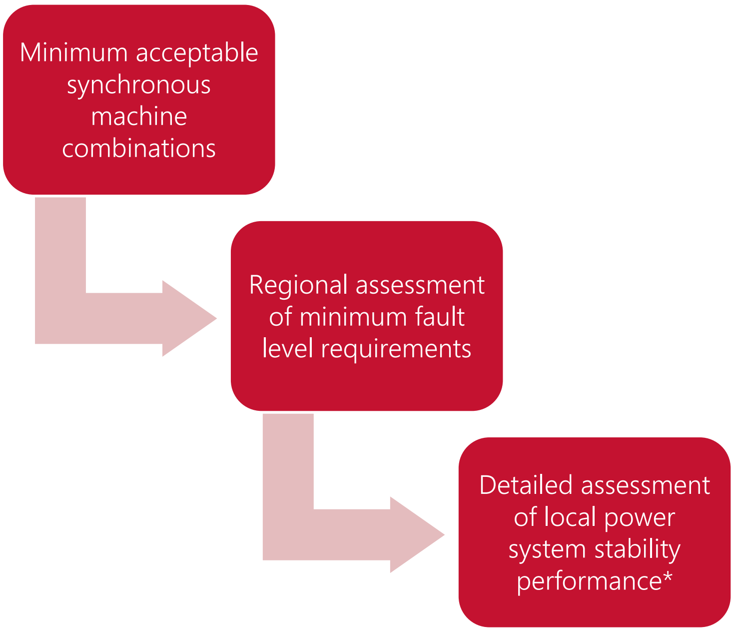
[64] Although the 2018 release of the requirements methodology also noted an initial stage calculating minimum fault level requirements using only steady state analysis and historical values, this approach has now been superseded as AEMO has progressively used EMT analysis to understand the fault levels in more detail for each region.

[65] See Section 9.1.1 in AEMO's System Strength Requirements Methodology July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

technical minimum fault level. If more IBR connects in close proximity to these nodes, then any fault level headroom will progressively be reduced.

As discussed in Section 1.3, AEMO expects that as the understanding of system strength matures, the calculation of the minimum three phase fault levels will continue to evolve as technology changes. For periods towards the end of the five-year outlook, where future network and generator characteristics are less certain, less detailed steps can be applied in order to determine requirements and shortfalls, as permitted in the System Strength Requirements Methodology.

Figure 40 Steps for calculating minimum three phase fault levels



* In cases where future network and generator characteristics are more uncertain, this step may be performed in parallel with transmission network service provider assessment of system strength services to be made available to meet the requirements.

Assumptions for and application of the minimum three phase fault level requirements

The minimum three phase fault levels are calculated as the minimum amount needed to allow the power system to be operated during normal operating conditions as well as allowing for credible contingency events[66]. These levels have been set to ensure generators remain stable and connected, system protection schemes are able to operate as designed, and power quality and voltage stability is maintained.

When interpreting the levels, it is important to note the following assumptions and applications of the requirements:

- **New and modified generator connections** are required to mitigate their own impact on system strength and their impact is not remediated through the setting of these minimum levels, in accordance with the division of responsibilities discussed below. The 2020 ISP[67] provides some information about opportunities for coordinated delivery of system strength for new generators as the electricity system transitions, but the NER currently require that the impact of new generators must be addressed separate to the regional requirements.

[66] A credible contingency event is the unexpected outage of an element of the transmission system. NER 4.2.3 has more information on credible contingencies.

[67] AEMO, 2020 ISP, Appendix 7, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

- AEMO is providing both **pre-contingency and post-contingency minimum fault level requirements** for each node in this 2020 SSI Report[68]. Both the pre-contingent values, representing the normal operating conditions secure level of system strength required to be available, as well as the corresponding post-contingency requirement[69] in most cases, are defined. Appendix A4 provides details for the contingency events considered in this analysis.
- Application of the minimum three phase fault levels in the AEMO and transmission network service providers' real time operations is **subject to operating conditions** and the levels are converted to appropriate operating instructions before they are used[70]. For example, in some regions such as Victoria the post-contingency minimum fault level requirement is a key factor used to develop constraint equations applied in market dispatch by the AEMO control room when necessary, whereas in Tasmania the pre-contingency minimum fault level requirements are used to guide the use of contracted system strength and inertia services (and constraints, where necessary). This decision is made by AEMO and the transmission network operating rooms based on the unique network and generator configurations for each region and fault level node, accounting for relevant operational and limit advice.
- These levels apply for **normal operating conditions allowing for a credible contingency** and are not designed to address the impact of planned outages for network infrastructure. Under network outage conditions, additional actions can be taken to ensure the secure operating state of the power system is maintained. This could include limitations on generator output, temporary protection settings, network re-arrangement, restrictions on reactive device switching, and other market interventions within AEMO's powers. AEMO understands that it is increasingly difficult for maintenance outages to be taken in shoulder periods which coincide with minimum demand and therefore with potential system strength issues, and hopes to work with industry, TNSPs, and other market institutions on an appropriate solution to manage this emerging issue.
- Fault level is the currently accepted metric for **system strength** requirements. Assumptions used in the calculation of these fault level requirements are intended to allow this proxy to represent power system requirements as accurately as possible but are not intended to be appropriate for the full range of transmission system design and operation purposes – for example, different analysis is required when reviewing the effective settings for network protection.
- Where generators have delivered their own system strength remediation measures which can impact system strength levels, such as dedicated synchronous condensers, the assumed operation of these is noted in AEMO's assessment methodology for each region or node. Appendix A3 and Appendix A4 provide further details.

Division of responsibilities between AEMO, transmission network service providers, and generators

In the NEM, the present division of responsibilities for the provision of system strength is as follows:

- AEMO, in consultation with the TNSP or jurisdictional planning body[71], is required to determine the location of fault level nodes.

[68] With the exception of some fault level nodes in the Tasmania region, which will be subject to future assessment.

[69] 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 and being able to be restored to a secure operating state within 30 minutes, i.e. they are not secure fault level requirements for a network outage condition.

[70] For example, the application of the South Australia system strength requirements is described in AEMO's Transfer Limit Advice – System Strength in South Australia and Victoria, updated October 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

[71] The jurisdictional planning body is the entity having responsibility of planning the transmission system in a region.

- AEMO is required to determine the system strength requirements of fault level nodes across the NEM and identify whether a shortfall is likely to exist at any node in the future. For each fault level node, the minimum three phase fault level is determined and used as the basis for assessing system strength.
- The regional TNSP or jurisdictional planning body is required to ensure that system strength services are available to address any fault level shortfall declared by AEMO at a fault level node. In declaring a shortfall, AEMO nominates the date for which the network should make adequate system strength services available.
- Generators subject to the system strength remediation requirements must implement or fund system strength remediation, if necessary, to ensure that the connection (or altered connection) of the generator does not have an adverse system strength impact.

This report considers the regional system strength requirements in accordance with NER 5.20.7. Although some broader commentary is provided about the possibility for coordinated delivery of system strength for new generators, the impact of new generators is not included in the system strength requirements, projections or shortfall assessments in this report.

A2.2 Assessment of inertia requirements

AEMO applies the Inertia Requirements Methodology[72] to determine the inertia sub-networks of the NEM and then calculate the minimum threshold and secure operating levels of inertia for each inertia sub-network.

The minimum level is prepared for when the sub-network is islanded or at credible risk of being separated. The secure operating level is for when the sub-network is islanded.

AEMO has previously noted an intention to explore the concept of a NEM-wide inertia safety net in future (see Figure 41), with work is anticipated to start from March 2021, as detailed in the frequency control workplan.[73]

This section describes the inertia assessment methods at a high level, as well as key assumptions.

Section A5 provides details of the model setup for the Victoria and Queensland analyses.

Figure 41 Relationship between system condition and inertia levels

[72] AEMO, 2018 Inertia Methodology and Inertia Requirements, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2018/inertia_requirements_methodology_published.pdf?la=en&hash=392D87D6279F3DB21D7FA41C2283ABF6.

[73] AEMO, Frequency Control Work Plan, September 2020, at https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

Inertia sub-regions and assessment of likelihood of islanding

Consistent with the 2018 assessment[74] and clause 5.20B.1(b) of the NER, AEMO defines the inertia sub-networks of the NEM as aligning with the NEM regions.

AEMO must consider the likelihood of an inertia sub-network becoming islanded when determining whether there are inertia shortfalls for the sub-network, as required in NER clause 5.20B.3(b)(2). Table 14 provides the 2020 assessment of likelihood of any inertia sub-networks becoming islanded.

Table 14 2020 Assessment of likelihood of islanding of each inertia sub-network in the NEM

Inertia sub-networks	Interconnections	Likelihood of islanding
Queensland	• One 330 kV AC double-circuit to New South Wales. • One DC link to New South Wales.	Likely
New South Wales	• One 220 kV and three 330 kV AC connections to Victoria. • One 330 kV AC double-circuit and one DC link connection to Queensland.	Unlikely
Victoria	• One 220 kV and three 330 kV AC connections to New South Wales. • One double-circuit 275 kV AC and one DC link connection to South Australia. • One DC link to Tasmania.	Unlikely
Tasmania	• One DC link to Victoria.	No synchronous AC links, therefore, always islanded for purposes of inertia assessment.
South Australia	• One 275 kV AC double-circuit to Victoria. • One DC link to Victoria.	Likely

Assessment of minimum threshold level of inertia and secure operating level of inertia

AEMO must assess the minimum threshold level of inertia for each inertia sub-network for when it is either islanded[75] or at credible risk of being islanded[76] from the NEM, as well as the secure operating level of inertia for when the sub-network is islanded.

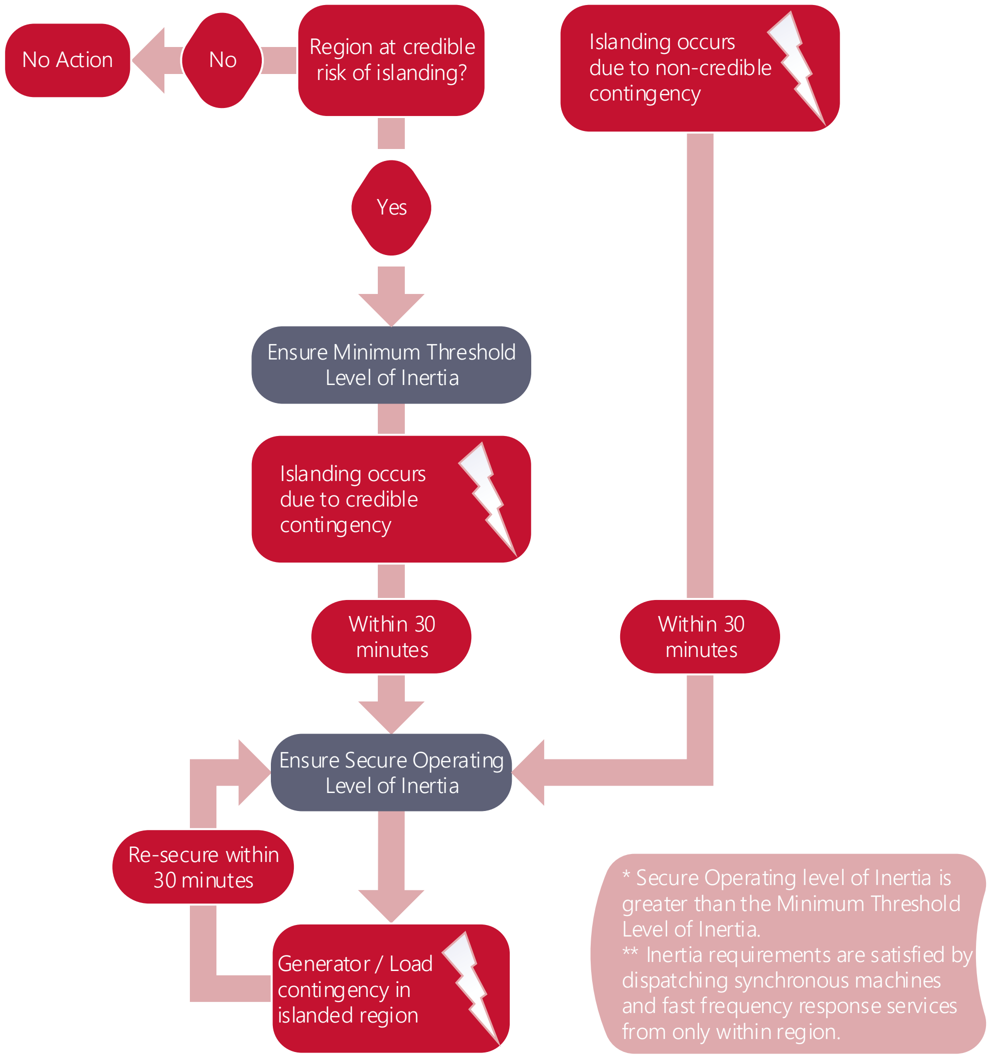
The relationship between the minimum threshold level of inertia and the secure operating level of inertia and how they are called into operation is demonstrated in Figure 42.

[74] AEMO, Inertia Requirements and Shortfall, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[75] AEMO's Frequency Operating Standards note the different frequency requirements that apply for different system conditions, including when a region is islanded (separated). The standards are available at https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d36f5a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf.

[76] This can include being due to network outages, when double circuit contingencies are declared credible (for example, due to lightning or bushfire), or if an interconnector has a non-credible contingency declared as a protected event.

Figure 42 Relationship between minimum threshold level of inertia and secure operating level of inertia



Defining the inertia requirements

Clause 5.20B.2(b) of the NER requires AEMO to calculate the inertia requirements for each inertia subnetwork in accordance with the inertia requirements methodology[77]. The inertia requirements are specified as:

- The minimum threshold level of inertia is the minimum level of inertia required to operate the inertia sub-network in a satisfactory operating state when islanded[78], or is at risk of islanding[79].
- The secure operating level of inertia, being the minimum level of inertia required to operate the inertia sub-network in a secure operating state when islanded[80]. AEMO considers an islanded region is in a secure operating state if the following conditions are met:
  - The islanded region is in a secure operating state prior to a contingency.

[77] AEMO, Inertia Requirements Methodology, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[78] Clause 5.20B.2(b)(1) of the NER

[79] Clause 4.4.4 of the NER

[80] Clause 5.20B.2(b)(2) of the NER

– The islanded region lands in a satisfactory state following the occurrence of any credible contingency and be able to be restored to a secure operating state within 30 minutes[81].

One of the key considerations in determining if an inertia sub-network, while islanded, is in a satisfactory operating state is whether frequency within the island is being maintained within an acceptable frequency range. An acceptable frequency range is achieved if the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band[82].

The minimum threshold level of inertia and secure operating level of inertia are inherently linked via whatever credible contingency event has the greatest impact on frequency control and rate of change of frequency (RoCoF)[83]. The Frequency Operating Standard (FOS)[84] summarises the different frequency bands applicable in the NEM.

Minimum threshold level of inertia

AEMO models an islanded region, then simulates a generation dispatch based on the minimum system strength requirements for that region. Provided the difference between this dispatch model and the secure operating level of inertia can met by fast-start generation within 30 minutes, then the minimum threshold level of inertia is determined by this outcome. If this condition cannot be met, the minimum level of inertia is increased until this condition is satisfied.

Secure operating level of inertia

To calculate the secure operating level of inertia, AEMO models an islanded region, then simulates a range of credible contingencies, including disconnection of generators and large loads. Operating as an island requires all necessary services to be sourced from only within the region. The generation dispatch is iteratively adjusted until the islanded region is in a satisfactory operating state after the worst credible contingency. From this state, the total inertia required is calculated based on which generators (or other providers of synchronous inertia or fast frequency response) have been dispatched.

Both the minimum threshold level of inertia and the secure operating level of inertia are expressed in units of synchronous inertia (megawatt-seconds). Inertia shortfalls can be addressed using inertia network services from synchronous inertia sources. Inertia support activities can provide a complementary service to synchronous inertia sources as they allow the inertia sub-network to remain in a satisfactory operating state or a secure operating state at lower levels of synchronous inertia. Inertia support activities can be provided by non-synchronous sources, for example FFR from battery energy storage systems (BESS)[85].

Assumptions for 2020 assessment of Queensland, Victoria and South Australia

This 2020 assessment includes a combination of updated requirements for the Queensland, Victoria and South Australia regions, as well as noting requirements assessed previously for New South Wales and Tasmania regions.

For the updated requirements provided in this report, key updated assumptions are listed below and discussed in the following sections.

- Credible contingency events have been updated, particularly with inclusion of unintended disconnection of distributed PV generation in disturbances.

[81] Clause 4.2.6 of the NER

[82] Clause 4.2.2(a) of the NER

[83] Although maintenance of frequency within an acceptable range forms the focus for a satisfactory operating state, consideration is also given to the oscillatory stability of all generators in an islanded region as well as voltages returning to nominal levels following a credible contingency.

[84] AEMC, Reliability Panel AEMO, January 2020, at https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

[85] Clause 5.20B.5 of the NER

- Modelling of primary frequency response (PFR) in the Victoria region as a result of the mandatory primary frequency response rule[86].
- Reduced 'load relief' due to observations of the South Australia islanding event in February 2020.
- Modelling of FFR capability for utility-scale batteries and other sources, as an alternative to synchronous inertial response.
- Frequency control ancillary services (FCAS) modelled for generators and large loads.

Unintended distributed PV disconnection resulting from credible contingency events

Credible contingency events which result in the most onerous frequency disturbance conditions within an islanded region have been updated in this assessment and now account for the coincident unintended loss of distributed PV. The coincident loss of distributed PV adds to the total contingency size for a given study. The necessity of modelling this coincident generation loss is driven by the considerable evidence of distributed PV disconnecting from the grid in response to short-duration voltage dips caused by faults on the network[87].

AEMO has applied a dynamic power system model prepared using recent distributed PV and behind-the-meter load observations to project this unintended undervoltage disconnection behaviour. This model was used in the 2020 ESOO[88] to forecast a range of net loss of distributed PV that would likely result from the most severe credible contingency[89]. Table 15 shows the outcomes of this model, listing the largest net loss of distributed PV which has been applied in this 2020 SSI Report.

For the Victoria and Queensland regions, the maximum possible net distributed PV losses modelled for each year have been selected from within the 2020 ESOO forecast ranges, as summarised in Table 16. Beyond 2021-22, it is assumed that these additional losses will not increase, as it is assumed that distributed PV units installed after the end of 2021 will have improved disturbance ride-through capabilities from the updated AS/NZS 4777.2 standard[90]. Should there be any delay in implementation of the new standard, these assumptions will need to be revisited in future inertia requirement assessments. The largest net loss of distributed PV has only been applied to a subset of the credible contingency events studied for each region. This is due to either little or no distributed PV being online for a particular study, or a contingency event not resulting in a severe enough voltage depression to trip off distributed PV.

For the South Australia region, the maximum possible net distributed PV loss modelled for each year has been taken from 2020 Notice of South Australia Inertia Requirements and Shortfall[91] assessment. Additionally, the loss is assumed constant for the five-year outlook due to the recent enactment of the South Australian Government's Regulatory Changes for Smarter Homes[92] rules that came into effect from September 2020. These rules ensure that the net distributed PV loss can no longer increase, as newly installed PV generating systems must now comply with new voltage ride-through standards developed by AEMO[93]. AEMO anticipates the revised AS/NZS 4777.2 standard will supersede South Australia's Regulatory Changes for Smarter Homes rules when implemented.

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[86] AEMC, Mandatory Primary Frequency Response, June 2020, at https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

[87] ARENA, Technical Integration of DER Report, at https://arena.gov.au/projects/enhanced-reliability-through-shorttime-resolution-data-around-voltage-disturbances/ and https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

[88] AEMO, 2020 ESOO August 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en.

[89] The most severe credible contingency in each region was that which resulted in the largest disconnection of net distributed PV and was not necessarily associated with a contingency of the largest online generator in the region.

[90] AEMO, AS/NZS 4777.2 – Inverter Requirements Standard, 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.

[91] AEMO, 2020 Notice of South Australia Inertia Requirements and Shortfall, August 2020, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en.

[92] Government of South Australia, Regulatory Changes for Smarter Homes, September 2020, at https://www.energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes.

[93] AEMO, Short duration undervoltage response test, July 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/der/2020/vdrt-test-procedure.pdf.

Table 15 Net distributed PV disconnection (in MW) for most severe credible fault during the most severe period

Year	Victoria*	Queensland*	South Australia
2021	90	50	150
2022	250	130	150
2023	250	130	150
2024	250	130	150
2025	250	130	150

* The maximum net loss of distributed PV has only been applied to a subset of the credible contingency events studied for each region. This is due to either little or no distributed PV being online for a particular study, or a contingency event not resulting in a severe enough voltage depression to trip off distributed PV. For further details on the specific contingency events considered refer to Appendix A5.

Mandatory primary frequency response from generators

PFR provided by generators can help reduce the RoCoF following frequency disturbances[94] on the power system and can reduce the total minimum threshold and secure operating levels of synchronous inertia required in a region.

Scheduled and semi-scheduled generators are required, under the Interim Primary Frequency Response Requirements (PFRR)[95], to provide a self-assessment of their ability to meet the Interim PFRR. These requirements came into effect on 4 June 2020 and are expected to be progressively enabled in tranches across all scheduled and semi-scheduled generator units capable of operating in frequency response mode. The Interim PFRR are due to sunset 4 June 2023 as the AEMC anticipates implementation of further reforms with respect to provision of frequency control services prior to June 2023.

Under the interim requirements target, generators will have to provide frequency response within a narrow dead band, and to disable any control features that act to suppress a generating unit's active power response to a frequency disturbance within the range that the plant is capable of safely and stably operating. However, the requirements do not oblige a generator to reserve headroom (or foot room) to provide a frequency response. This will continue to be procured through the FCAS market.

The final submission date for generators' self-assessments is 17 February 2021, with AEMO only receiving a subset of PFR models at the time of undertaking the analysis for this report. Taking into consideration the ongoing implementation of the interim PFR process, AEMO has only modelled a generator's PFR where the models are available for this report.

Reduced load relief

Reduced load relief change assumed in this analysis reflects the changing behaviour of loads in response to contingencies with the increasing penetration of power electronics-based equipment[96]. Load relief is an observed change in electricity demanded from the system when the frequency level changes. Load relief can reduce the severity of the impact of contingency events, and so can directly impact the determination of inertia requirements.

[94] The ability to reduce the RoCoF is highly dependent on the type of synchronous generation (i.e. gas, coal, hydro etc) online and its corresponding speed of frequency response to frequency deviations.

[95] AEMO, Interim Primary Frequency Response Requirements, June 2020, at https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf?la=en.

[96] AEMO, Review of NEM load relief, November 2019, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/load-relief/update-on-contingency-fcas-nov-2019.pdf.

Emerging need to consider fast frequency response services

FFR services provided by inertia support activities have been modelled for the South Australia and Victoria regions, as the inclusion of these services reduces the total required synchronous inertia provided by synchronous machines. Although synchronous inertia services can address the inertia requirements, some form of fast active power response, such as FFR, is increasingly considered to be an effective alternative. This became evident during the recent prolonged operation of the South Australia region as an island, when utility-scale batteries were dispatched to provide frequency control to maintain system security[97].

Frequency control ancillary services (FCAS) from generators and large loads

FCAS has been modelled for generators and large loads based on typical bidding practices for each registered participant in the FCAS markets. FCAS provided by generators and loads function to arrest and restore frequency deviations, and thus have a direct impact in determining inertia requirements for a region.

NEM-wide inertia safety net

AEMO assesses requirements for inertia within each NEM region boundary (an inertia sub-network), and defines a minimum level of inertia for the region (or sub-set of a region) when the region is at risk of islanding as well as a secure level for when the region is islanded. As outlined in AEMO's Renewable Integration Study (RIS) Phase 1 Report[98], the framework does not allow AEMO to define minimum or secure levels for a region if there is no islanding or risk of island for that region. There are also there are no provisions to allow AEMO to set minimum inertia requirements for operating two or more regions islanded together.

For regions such as Victoria and New South Wales, the number of inter-regional interconnections means the risk of regional islanding is deemed to be remote; as synchronous generation decommits into the future, the amount of inertia seen across the whole NEM will therefore continue to decrease. This could result in reduced frequency control, higher RoCoF events, increase in amounts of FCAS being needed, and an overall reduction in system reliability.

For these reasons, AEMO's RIS Stage 1 Report initially recommended investigation of a NEM-wide inertia safety net for system intact conditions, which was explored in detail in the report's Appendix B[99]. AEMO provided an initial projection of when this safety net may be required in Appendix 7 of the 2020 ISP[100], and further work is anticipated to start from March 2021, as detailed in the frequency control workplan[101].

A2.3 System strength and inertia shortfall projection method

The 2020 SSI Report uses the calculation method below to project available system strength and inertia in the NEM. This is the same methodology and requirements as used in the 2020 ISP[102].

The three phase fault level is calculated as follows:

- A projection for output from synchronous units for each half-hour interval period is taken from market modelling results, based on typical synchronous machine dispatch patterns and informed projections of future operations.

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[97] AEMO, Preliminary Report – Victoria and South Australia Separation Event 31 January 2020, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/preliminary-report-31-jan-2020.pdf?la=en.

[98] AEMO, Renewable Integration Study, April 2020, at https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris.

[99] AEMO, RIS Stage 1 Report, Appendix B, March 2020, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en.

[100] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[101] AEMO, Frequency Control Work Plan, September 2020, at https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

[102] AEMO, 2020 ISP, Appendix 7, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp. Note that while the system strength and inertia projections in the 2020 ISP align with the process aligned above, the 2020 ISP also separately includes a different process for considering potential system strength requirements within each of the REZs.

- The status is applied to the steady state network model. The model assumes typical parameters for projected new synchronous plant such as gas peaking, closed-cycle gas turbines, and pumped hydro. For pumped hydro the plant is assumed to be synchronous, apart from Snowy 2.0 units where half are assumed to be inverter-connected units[103].
- The model includes TNSPs' committed synchronous condensers and network upgrades.
- The model calculates fault level contribution from synchronous sources only, with no contribution from IBR.
- The model includes synchronous condensers included in committed projects to meet Generator Performance Standards.
- This model takes into account certain generators ability to typically operate in synchronous condenser mode at times. This is taken into consideration in the post-processing of the fault calculation results.
- The model does not assume any contribution from system strength mitigation with future inverter-based resources.
- All IBR including BESS are switched off.
- The fault level is then calculated at each fault level node.
- The fault level is calculated for intact system conditions, and for outage of single network or generation elements.
- The network model used in the calculations is updated in a time sequential manner to account for future ISP network upgrades.
- The process is repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

The process for calculating the inertia is as follows:

- The status of all synchronous units is extracted from the market modelling outputs for each half-hour interval.
- The inertia coefficient of in-service machines in each region is summated for each half-hour interval.
- The inertia coefficient of TNSPs' committed synchronous condensers is added to the results, as these are not set by the market modelling outputs.
- The process is repeated for each half-hour market modelling interval to produce annual inertia duration curves.

A2.4 Shortfall declaration assessment

Declaration of a system strength shortfall

To declare a system strength shortfall (a fault level shortfall), AEMO must assess whether, in AEMO's reasonable opinion, there is or is likely to be a fault level shortfall in the region, and assess AEMO's forecast of the period over which the fault level shortfall will exist[104].

To complete this, AEMO:

- Selects one or more scenarios or projections from market modelling results (see Section A2.5) and applies them in a power system model to project the fault level at each of the fault level nodes over the five-year outlook period (see Section A2.3).

[103] Modelling Snowy 2.0 in the NEM, Snowy Hydro, at https://www.snowyhydro.com.au/wp-content/uploads/2020/04/MJA-NEM-Study-Public-Report-3Dec2018.pdf.

[104] NER 5.20C.2

- Compares the fault level projection results against the requirements for each node (see Section A2.1) and identifies potential system strength shortfalls where the synchronous three phase fault level at a node falls below the minimum fault level requirements for more than 1% of the year over the coming five-year period.
- Where a potential system strength shortfall is identified, considers the potential drivers of the shortfall and forms a reasonable opinion of the likelihood of the shortfall existing. AEMO considers many factors in forming this reasonable opinion, including but not limited to market modelling results, market trends and insights, and relevant government policy announcements.

Details about the shortfall assessment are provided in the System Strength Requirements Methodology[105]. Arrangements for how AEMO requires that TNSPs or jurisdictional planning bodies make services available to address the shortfall are covered in NER clauses 5.20C.3 and 5.20C.4.

Declaration of an inertia shortfall

To declare an inertia shortfall, AEMO must assess whether, in AEMO's reasonable opinion, there is or is likely to be an inertia shortfall in the region, and assess AEMO's forecast of the period over which the inertia shortfall will exist[106].

To effect this, AEMO:

- Selects one or more scenarios or projections from market modelling results (see Section A2.5) and extracts the information needed to project inertia for each inertia sub-region of the NEM over the five-year outlook period (see Section A2.3).
- Compares the inertia projection results against the requirements for each inertia sub-network (see Section A2.2) and identifies potential inertia shortfalls where the available inertia falls below the minimum requirements for more than 1% of the period over the coming five-year period.
- Where a potential inertia shortfall is identified, considers the potential drivers of the shortfall and forms a reasonable opinion of the likelihood of the shortfall existing. AEMO considers many factors in forming this reasonable opinion, including but not limited to market modelling results, specific system security aspects that may apply during islanded operation, market trends and insights, and relevant government policy announcements.

Details about the shortfall assessment are provided in the Inertia Requirements Methodology[107]. Arrangements for how AEMO requires that TNSPs or jurisdictional planning bodies make services available to address the shortfall are covered in NER clauses 5.20B.4, 5.2B.5 and 5.20B.6.

A2.5 Market modelling methodology and assumptions

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

Market modelling projections prepared for the 2020 SSI Report

To project generation dispatch over the coming decade and therefore derive any potential shortfalls for the 2020 SSI report, AEMO built on the 2020 ISP outcomes and undertook further market modelling to reflect recent trends and emerging market conditions. While the 2020 SSI Report shares all the fundamental assumptions used in the 2020 ISP, the latest minimum and maximum demand projections from the 2020 ESOO have also been incorporated.

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105 AEMO, System Strength Requirements Methodology, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

106 NER 5.20B.3

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

Using these updated forecasts, AEMO has leveraged a time-sequential model to simulate three different projections relevant for system strength and inertia:

- A **traditional operations** projection, applying announced retirement dates for synchronous generators in the NEM, or technical end-of-life dates where retirement dates are not announced. Changes to unit commitment profiles of existing thermal generation units are not considered.
- A **high renewable energy** projection, with increased uptake of both utility-scale and distributed IBR that also incorporates earlier-than-announced unavailability of thermal generation[108]. This primary purpose of this projection is to identify future risks to the power system.
- A set of **high renewable energy with flexible operation** sensitivities, simulated for the financial year 2025-26 and 2029-30 with additional analysis of the potential impact of low market prices incentivising seasonal withdrawal or intra-day decommitment of synchronous generation units. Similarly, the primary purpose of this projection is to identify future risks to the power system.

Observation of recent market trends in the NEM

Preparation of the market modelling for the 2020 SSI Report includes incorporation of recent spot price trends and acknowledgment of current futures prices:

- NEM wholesale energy spot prices have been in decline across most NEM regions over the past year, with a key driver being increased supply from new inverter-based generation connections and continued uptake of distributed PV. Average time of day prices are close to the estimated short run marginal cost for many coal-fired power stations during the middle of the day, particularly in the Queensland region.
- Market expectations of electricity market prices, reflected in Sydney Futures Exchange prices for calendar years 2021, 2022 and 2023, have dropped significantly (by between 22% and 35%) across New South Wales, Victoria and Queensland in the past year[109], and reflect an expectation that current, relatively subdued market prices will continue.

Outcomes from market modelling projections for the 2020 SSI Report

Market modelling results completed for this 2020 SSI Report forecast a decrease in dispatch of coal-fired generation in the next decade, including within the next five years. Under the projections completed with increased uptake in IBR and including modelling consideration of the possibility of unit decommitment, the reduction in forecast generation from synchronous generating units is more prominent.

Beyond new committed generation capacity, high volumes of additional renewables capacity (both behind the meter and utility-scale) is projected to be installed by 2029-30 in the traditional operations projection and in the high renewable energy uptake projection respectively, driving a risk of further reduced spot prices, thus impacting on operational decisions of existing assets and potentially influencing unit commitment of synchronous generating units.

All projections were prepared using the bidding behaviour model described in AEMO's Market Modelling Methodology[110].

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108 In this projection existing generators are assumed to become unavailable earlier than announced if this minimises total system costs. The capacity outlook model co-optimises for an early unavailability by avoiding the overhead cost of keeping the unit in service.

109 Source: ASX, comparing futures prices at 12 November 2019 and 11 November 2020.

110 AEMO, August 2020, Market modelling methodologies, see https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

A2.6 Future electricity demand

The analysis conducted for this SSI Report has been prepared for the coming decade by applying the minimum and maximum electricity demand forecasts[111] in the 2020 ESOO released in August 2020. These forecasts can be reviewed in full by referring to the 2020 ESOO on AEMO's website[112].

The 2020 ESOO projected a marked decline in minimum demand forecasts, principally driven by the continued strong uptake of distributed PV (including residential, commercial, and larger embedded and PV non-scheduled generation systems[113]). The 2020 ESOO forecasts include an upwards revision of distributed PV uptake assumptions driven by strong sale figures in 2019 with no apparent slackening throughout 2020 (despite COVID-19), leading to approximately 2.1 gigawatts (GW) of new installations over the 2019 calendar year, and a total capacity of distributed PV systems in the NEM of about 10.7 GW[114].

Moreover, calendar year 2020 has seen new records set for minimum demand in multiple regions. In Q3 2020, NEM-average operational demand decreased by 313 MW (1.4%) compared to Q3 2019, due to increased distributed PV (218 MW) and reduced underlying demand. On 7 November 2020, South Australia experienced a new daytime minimum demand record of 270 MW. This was 109 MW lower than the previous record set on 13 September 2020. A Victorian minimum demand record of 3,073 MW was achieved on 6 September, 144 MW lower than the previous record set during Q4 2017, with distributed PV accounting for 31% of underlying demand. Queensland also experienced a record minimum demand of 3,712 MW on 27 September 2020.

The minimum demand forecasts are particularly important for assessing system strength and inertia requirements and projections, because when there is less demand on the network, less generation is needed and so fewer synchronous generators (and their associated system strength and inertia services) can be assumed to be available.

Observed minimum demands in the NEM are now approaching thresholds where challenges will be encountered in managing voltage, system strength, and inertia. Due to the declining minimum demand forecasts, by 2024-25 all regions are expected to experience minimum operational demand during daytime. In South Australia, minimum demand is forecast to reach close to zero by 2022-23 (before potentially going negative towards the end of the next decade).

In addition, minimum demand is now associated with higher distributed PV generation, which is understood to be increasing credible contingency assumptions in the NEM (refer to Section A2.2 for more information).

A comparison of the 2019 distributed PV forecasts[115] and 2020 distributed PV forecasts[116] is shown in Figure 43.

Figure 44 shows the minimum demand forecasts applied in this report for the traditional operations and high renewable energy projections.

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[111] Both the Central scenario and the Step Change scenario forecasts were tested in this analysis. Results for 'traditional' operations are based on Central scenario forecasts and results for 'high renewable energy and 'high renewable energy with flexible operation' are based on Step Change scenario projections.

[112] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en.

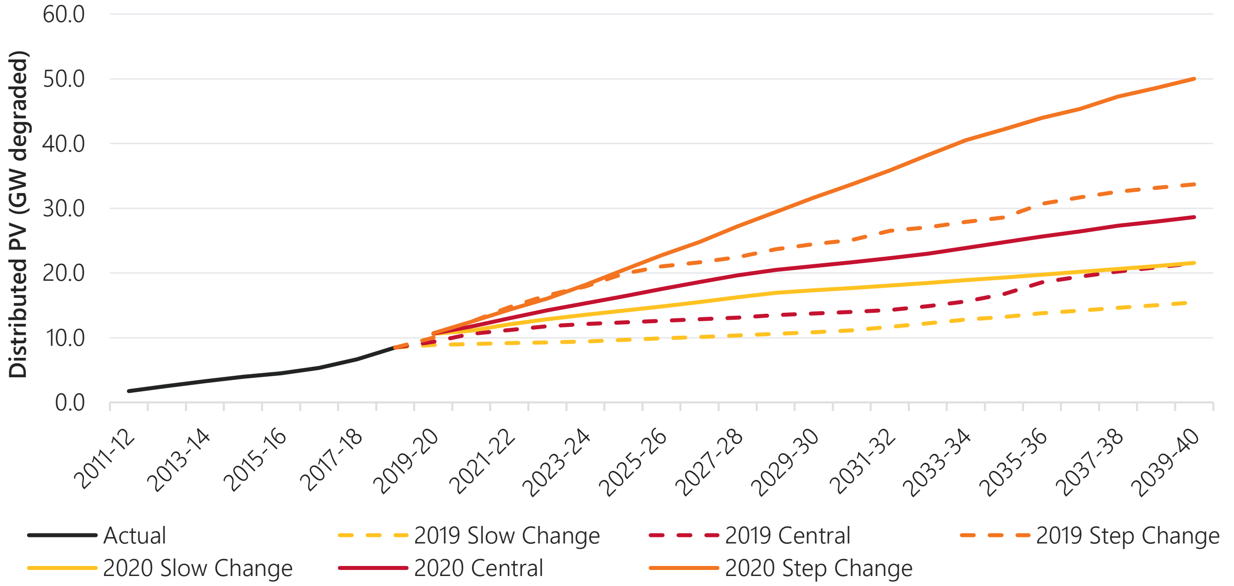
[113] Residential and commercial systems are defined as systems smaller than or equal to 100 kilowatts (kW). PV non-scheduled generation is defined as systems greater than 100 kW, up to 30 MW. Distributed PV covers all residential, commercial, and non-scheduled systems.

[114] Installed capacity estimate as at 30 June 2020, unadjusted for degradation.

[115] Used in the 2020 ISP and 2019 ESOO.

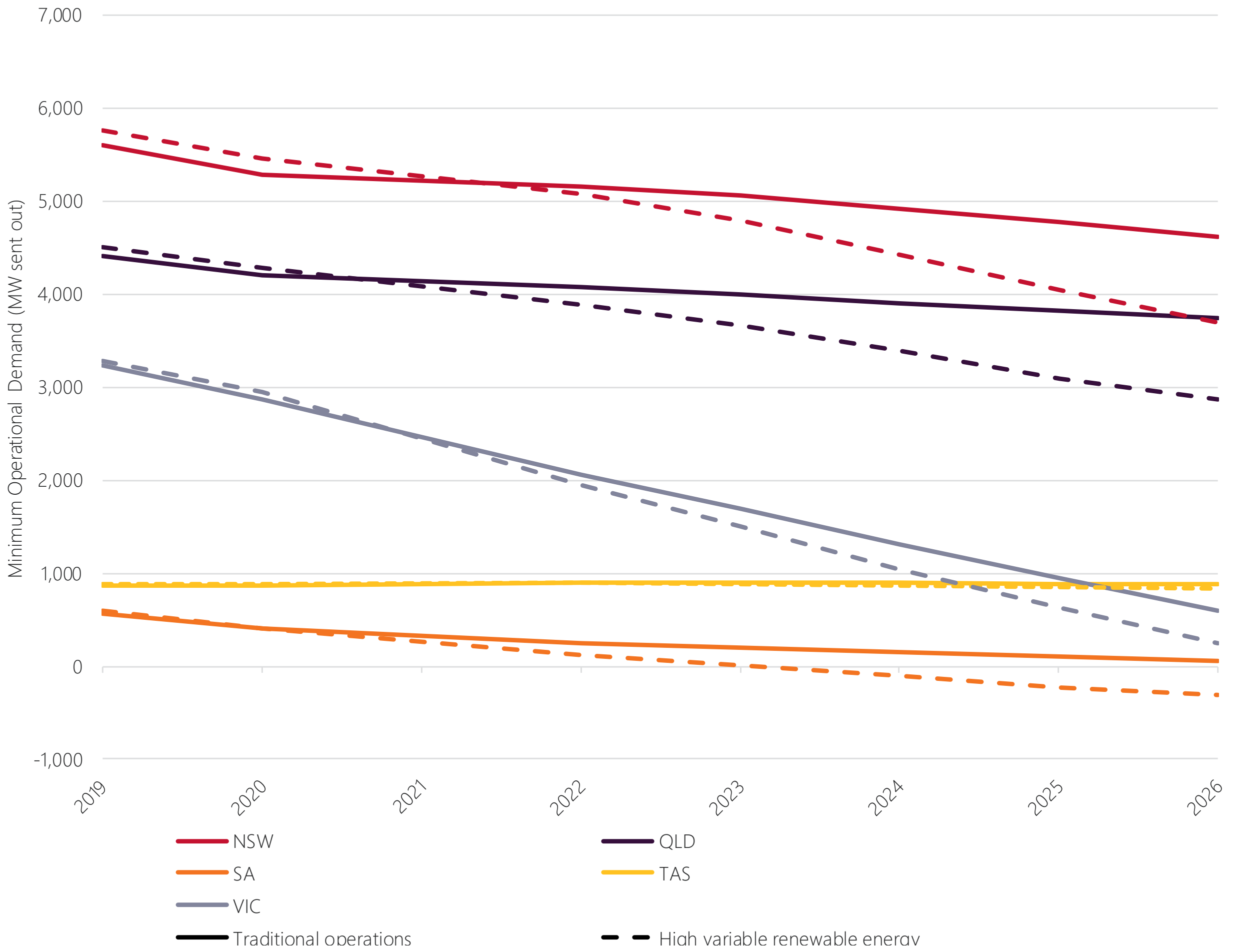
[116] Used in the 2020 ESOO.

Figure 43 Comparison of 2020 and 2019 ESOO projections for distributed PV installed capacity in the NEM



Note: this figure shows 2020 ESOO results and refers to the central and slow change scenario results in that report. Information about the scenarios is available on AEMO's website at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

Figure 44 Minimum demand projections for traditional operations and high renewable energy projections



A2.7 Future electricity generation

The analysis conducted for this SSI Report has been prepared for the coming decade by applying the 2020 ISP modelling and network assumptions but with the application of the updated minimum and maximum electricity demand forecasts provided in the 2020 ESOO[117] released in August 2020[118].

As such, the future generation mix modelled for this report for the system strength and inertia projections reflects the existing and committed generation projects as well as new generation and transmission augmentations projected over the 10-year outlook.

For the purposes of assessing the present minimum system strength and inertia requirements, more precise near-term assumptions are required, and these are covered in these Appendices.

Future uptake of inverter-based resources can be expected across the NEM

Recent years have seen high volumes of new inverter-based generation investment in the NEM. AEMO's 2020 ISP projects significant changes in the electricity supply mix over the next 20 years, including uptake of inverter-based resources and several coal-fired power stations reaching their stated end-of-life over the next 20 years[119].

The current generation project pipeline[120] has over 50 GW of potential projects.

Further supporting future generation investments, new government policies indicate strong likelihood of more utility-scale and distributed renewable energy generation and storage projects in the NEM. AEMO has not explicitly included the following three new government policies in the analysis for this SSI Report due to short timing between policy announcement and publication requirements, but AEMO is currently considering how best to incorporate these in future power system planning and forecasting publications:

- The New South Wales Government announced its Energy Infrastructure Roadmap[121] and passed supporting legislation through the New South Wales Parliament in November 2020. The roadmap is intended to deliver approximately 12 GW of new transmission capacity through the Central-West Orana, New England and South West REZs by 2030, and support an estimated 3 GW of new 'firm capacity' in the New South Wales grid.
- In November 2020, the Victorian Government announced significant financial support to develop six REZs across the region[122]. These zones align closely with the REZs outlined in AEMO's 2020 ISP.
- Also in November 2020, the Queensland Government announced funding for the development of three new REZs[123] that extend from Far North Queensland to the Darling Downs west of Brisbane, and encompass most of the eight Queensland REZs identified in AEMO's 2020 ISP.

However, this report does take into account the Tasmania Renewable Energy Target[124] that was announced in March 2020, and subsequently legislated[125] by the Tasmanian Government in November 2020. The target

117 At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

118 Both the Central scenario and the Step Change scenario were tested in this analysis. Results for 'traditional' operations are based on Central scenario forecasts, and results for 'high renewable uptake' and 'high renewable uptake with flexible operation' are based on Step Change scenario forecasts.

119 See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

120 See AEMO's Generation Information publication for further details at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. This pipeline includes projects at various stages of certainty of progression.

121 See https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap.

122 See https://www.premier.vic.gov.au/backing-new-energy-breakthroughs-and-victorian-jobs.

123 See https://www.dnrme.qld.gov.au/energy/initiatives/queensland-renewable-energy-zones/about.

124 See http://www.premier.tas.gov.au/site_resources_2015/additional_releases/renewable_energy_target_to_deliver_for_tasmania.

125 See http://www.premier.tas.gov.au/site_resources_2015/additional_releases/improving_the_playing_field_across_tasmania/forging_a_manufacturing_future/renewable_energy_target_passes_parliament.

calls for the Tasmania region of the NEM to achieve 200% renewable generation by 2040 and has been incorporated into the high renewable energy projection.

Assumptions for end of life for thermal power stations

Table 16 lists existing thermal power stations in New South Wales, Victoria and Queensland, and their announced retirement dates[126] under the continued traditional operations projection used in the analysis for the 2020 SSI Report. In the lead up to these closures, the 2020 ISP projects a decline in coal-fired electricity generation volumes across Queensland, New South Wales and Victoria, as does the modelling undertaken for this 2020 SSI Report.

Table 16 Announced coal-fired power plant retirement dates, or technical end-of-life dates

Generator Name	Region	Expected closure (calendar year)**
Bayswater	NSW	2035
Eraring	NSW	2032
Liddell	NSW	2023
Mount Piper	NSW	2042
Vales Point	NSW	2029
Callide B	QLD	2028
Callide C*	QLD	2051
Gladstone	QLD	2035
Kogan Creek	QLD	2042
Millmerran	QLD	2051
Stanwell	QLD	2046
Tarong	QLD	2037
Tarong North	QLD	2037
Loy Yang B	VIC	2047
Loy Yang A	VIC	2048
Yallourn W	VIC	2032

* CS Energy has not submitted retirement dates. Instead, this table lists the end-of-technical life assumptions from the 2018 ISP assumptions book.
** Where closures of power stations are staged, the year shown is the final year of operation of the last unit at that station.

A2.8 Major transmission network upgrades

The power system analysis completed for this report models the transmission network as it currently exists and includes selected major transmission network upgrade projects over the five-year outlook. These projects have been taken from the 2020 ISP[127], which proposed a dynamic whole of system optimal pathway for the transition of the NEM for the next 20 years.

[126] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

[127] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

Table 17 lists committed, actionable or future ISP projects[128] included in the analysis for this 2020 SSI Report.

Table 17 Transmission network upgrades included in analysis

Network Project	Augmentation Detail
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 are expected to be commissioned by mid-2021.
Western Victoria transmission network	The Western Victoria transmission network project includes two stages. The first stage includes installation of wind monitoring equipment along with the upgrade of substation limiting transmission plant on to uprate the Moorabool-Terang-Ballarat 220 kV lines and the 220 kV network between Bendigo and Red Cliffs. The second stage includes a new terminal station north of Ballarat with two 1,000 MVA 500/220 kV transformers, and 220 kV double circuit transmission lines from the new terminal station to Bulgana (via Waubra), and a new 500 kV double circuit transmission lines from the new terminal station to Sydenham.
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.
VNI Minor	VNI Minor is the proposed 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 NSW to manage the overload of transmission lines.
Project EnergyConnect	Project EnergyConnect is a proposed new double circuit 330 kV transmission line between Robertstown in South Australia and Buronga, Dinawan and Wagga Wagga in New South Wales, as well as an additional 220 kV line between Red Cliffs and Buronga. Included are additional transformers at Robertstown and Buronga, reactive plant, and special protection schemes[129].
HumeLink	HumeLink is a proposed new 500 kV network triangle linking Bannaby, Wagga Wagga and Maragle in New South Wales.
Central-West Orana renewable energy zone (REZ) Transmission Link	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[130].
Gladstone grid reinforcement	The Gladstone Grid reinforcement includes rebuilding and reconfiguring the 275 kV transmission network between Calliope River and Bouldercombe, as well as a new 275 kV transmission line between Calvale and Larcom Creek. A third 132/275 kV Calliope River transformer is also required.

[128] In the ISP, committed projects are underway and have already received regulatory approval, actionable projects are already progressing or are to commence immediately after the publication of the 2020 ISP, and future ISP projects are not yet actionable but are expected to be in the future ISPs.

[129] See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-and-electranet-%E2%80%93-project-energyconnect-contingent-project.

[130] See https://energy.nsw.gov.au/renewables/renewable-energy-zones.

A3. EMT model setup for system strength

This Appendix provides additional detail regarding the system strength assessment methodology.

A3.1 Assessment methodology

AEMO carries out EMT studies to determine the minimum synchronous machine dispatch patterns for the Queensland, Victoria and Tasmania regions, using the EMT model of all regions in the NEM. This modelling includes detailed models of synchronous generators from major coal-fired, gas-fired, and hydro power stations in the relevant regions. Only inverter-based plants not subject to the system strength remediation requirements were considered in this assessment.

A3.1.1 Determination of minimum synchronous generation

To determine the fault level requirement, and therefore the fault level shortfall, different synchronous machine dispatches are considered in the relevant regions assessed as to whether they meet the success criteria. Subsequent sections of this appendix show the minimum synchronous dispatches for regions of the NEM, however for the regions not specifically mentioned (such as New South Wales and South Australia) the information below details their assumed dispatches.

A3.1.2 Successful synchronous machine scenarios

The study was set up to include different combinations of synchronous generation in each relevant region, comprising units dispatched for most of the year. For each scenario, a range of contingencies were tested to assess fault level impact or using EMT studies to assess system strength stability. Where the success criteria are not met, credible scenarios are developed which model additional synchronous machine options. The size and location of the additional synchronous machine options is based on practical considerations and verified in modelling to ensure stable operation for the same range of contingencies. The successful synchronous dispatches are then reflected in steady state analysis to determine the minimum three phase fault levels.

Success criteria

The success criteria used in the system strength assessment studies are outlined below.

- Generators, as well as relevant regional interconnectors, remain online.
- 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 acceptable range (0.95-1.05 p.u.).
- Post fault voltage oscillations are adequately damped[131].

[131] Notice of Queensland system strength requirements and Ross node fault level shortfall, AEMO, April 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-queensland-system-strength-requirements-and-ross-node-fault-level-shortfall.pdf?la=en.

South Australia – minimum synchronous generation

The system strength assessment for the South Australia power system was completed in 2017[132], and minimum synchronous machine dispatch patterns were identified. The published list of minimum synchronous machine dispatch patterns[6] was updated in February 2020 following commissioning of additional inverter-connected generators in South Australia.

Following a fault level shortfall declaration by AEMO in South Australia, ElectraNet, as the local TNSP and System Strength Service Provider, is currently installing four synchronous condensers to rectify the shortfall. AEMO performed detailed EMT analysis, which confirmed that the four synchronous condensers will meet system strength requirements without the need for additional synchronous generators under system intact conditions. These case studies included the synchronous inertia available from the four synchronous condensers fitted with flywheels, as well as the inertia provided by two synchronous generators assumed to be online at all times, in line with current planning assumptions around minimum unit commitment in South Australia[133].

New South Wales – minimum synchronous generation

EMT studies were conducted in 2019-20 to determine the acceptable minimum number of synchronous machines required to ensure system security can be maintained in the New South Wales power system[134].

The minimum acceptable synchronous machine dispatch identified following EMT studies resulted in lower minimum three phase fault levels at all fault level nodes, compared with the levels published in 2018. This is because the EMT studies have identified dispatch patterns with fewer synchronous machines than identified in 2018 are able to meet the success criteria.

AEMO examined the performance of the New South Wales power system and inverter-connected generators which are currently going through system strength impact assessment, to investigate whether reducing the number of minimum acceptable synchronous generators by one would result in any notable degradation of performance. The results indicated that with one fewer large synchronous machine dispatched, New South Wales power system performance is not degraded.

The system strength requirements were revised based on the findings of EMT studies, to include a minimum of seven large synchronous units in the New South Wales region.

A3.2 EMT model setup – Victoria

A3.2.1 Determination of minimum synchronous generation

To date, 33 different synchronous generator dispatch combinations have been tested. The selection of these combinations has considered both short- and medium-term availability and reliability of each synchronous generating unit at major power stations in Victoria. Among these 33 combinations, 19 are successful, meaning they provide sufficient system strength to each of the nodes in Victoria.

Many successful dispatch combinations consist of only units from large power stations, including Loy Yang A, Yallourn and Newport power stations. Each successful dispatch combination includes five large synchronous generating units. Hence, five synchronous units became the base case.

The minimum fault level requirement at the Hazelwood 500 kV node includes the need to ensure the nearby Basslink DC converter is able to operates in a stable manner. Minimum fault levels outcomes for the Victorian studies also consider minimum fault levels at the Tasmanian end of the DC link, and vice versa.

[132] AEMO, Second update to the to the 2016 National Transmission Network Development Plan, October 2017, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2017/second_update_to_the_2016_ntndp.pdf?la=en&hash=A9EE910B7DA3C1D88927871630C02B48.

[133] AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, at https://www.aer.gov.au/system/files/AEMO%20-%20Assumptions%20for%20South%20Australian%20GPG%20in%20the%202018%20ISP%20-%20August%202019.pdf.

[134] In compliance with Stage 1 of AEMO's System Strength Assessment Guidelines process.

Synchronous condensers installed by generators as part of their own system strength mitigation requirements were modelled online only when the associated solar farms were online.

Table 18 is taken from AEMO's Transfer Limit Advice – System Strength in South Australia and Victoria[135]. It summarises the combinations of synchronous generating units that provide sufficient system strength in Victoria to withstand a credible contingency, including the loss of a synchronous unit.

The four dispatch cases that utilise the five synchronous unit minimum dispatch in the EMT base case are highlighted in red in Table 18.

Table 18 Victoria system strength successful generator combinations

Combination	Loy Yang (A or B)	Yallourn W	Newport	Dartmouth	Bogong	Murray2	Mortlake	Jeeralang (A or B)	Valley Power
VIC_1	3	2							
VIC_2	4		1						
VIC_3	4	1							
VIC_4	3		1			2			
VIC_5	3		1	1	1				
VIC_6	3	1							3
VIC_7	3	1						3	
VIC_8	3		1					3	
VIC_9	3		1						3
VIC_10	3	1	1						
VIC_11	3					2		3	
VIC_12	3			1	1	2			
VIC_13	4							2	
VIC_14	4								2
VIC_15	4			1	1				
VIC_16	4						1		

A3.2.2 Contingencies considered

EMT analysis identified that system stability requirements in the West Murray area of Victoria would determine the minimum system strength requirements for the rest of the region. Screening of credible contingencies for the West Murray area was undertaken. From this screening, the following were the worst-case contingencies and were the focus of the system strength assessment of the West-Murray network:

- Contingency 1 – Two phase to ground fault and disconnection of Kerang – Bendigo 220 kV line, cleared within primary protection time requirements.

[135] Published December 2020, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice.

- Contingency 2 – Two phase to ground fault and disconnection of Ararat – Waubra – Ballarat 220 kV line, cleared within primary protection time, followed by inter-tripping of Ararat Wind Farm, Bulgana Wind Farm, Crowlands Wind Farm, Murra Warra 1 Wind Farm, and Waubra Wind Farm.
- Contingency 3 – Two phase to ground fault and disconnection of Red Cliffs – Buronga 220 kV line (OX1), cleared within primary protection time, followed by inter-trip of Broken Hill Solar Farm, Silverton Wind Farm, Limondale1 Solar Farm, Limondale2 Solar Farm, and Sunraysia Solar Farm.
- Contingency 4 – Two phase to ground fault and disconnection of Balranald – Darlington Point 220 kV line (X5), cleared within primary protection time, followed by inter-trip of Broken Hill Solar Farm, Silverton Wind Farm, Limondale1 Solar Farm, Limondale2 Solar Farm, and Sunraysia Solar Farm.
- Contingency 5 – Two phase to ground fault and disconnection of Darlington Point – Wagga 330 kV line (Line-63), cleared within primary protection time, followed by inter-trip of Broken Hill Solar Farm, Silverton Wind Farm, Limondale1 Solar Farm, Darlington-Point Solar Farm, and Sunraysia Solar Farm, and opening the Darlington Point end of Balranald – Darlington Point 220 kV line.
- Contingency 6 – Two phase to ground fault and disconnection of Kiamal1 Solar Farm, Kiamal2 Solar Farm, and Kiamal synchronous condenser, cleared within primary protection time.

A full-scale EMT model of the entire Victorian network was developed and used to study the Western Victoria system strength. As some network phenomena can propagate significant distances, the south west New South Wales network and generation was also represented.

A3.2.3 Prior outages modelled

The following 500 kV transmission circuits are considered out of service during these system strength study combinations:

- Hazelwood – South Morang 500 kV line 1.
- Hazelwood – Rowville 500 kV line 3.

These two circuits are normally switched off during low loading conditions for voltage control. Usually this coincides with a lower number of synchronous generators online, hence realistic low system strength conditions reflecting onerous operating scenarios.

A3.3 EMT model setup – Tasmania

A full-scale EMT model of the entire Tasmanian network was developed and used to study the Burnie system strength requirements. In all case studies, the following operational assumptions were considered:

- Studland Bay and Bluff Point Wind Farms were generating their maximum active power, 140 MW.
- The fault level at George Town as the nearest adjacent node to the Burnie node was maintained at its requirement of 1,450 MVA in the case studies. This ensured the region remained connected to the rest of the NEM.

A3.3.1 Determination of minimum synchronous generation

It was impractical to publish a list of minimum synchronous machine dispatch for the Tasmania power system, like those published for other regions. This is because the hydro synchronous machines are smaller in size than the large coal-fired synchronous machines on the mainland, and there are countless possible synchronous machine dispatch patterns which can meet the system strength requirements in Tasmania.

For this reason, AEMO modelled a subset of possible synchronous generating scenarios. To analyse the minimum fault level requirement for system strength at the Burnie node, synchronous machine dispatch scenarios were selected that provided different fault levels for system normal and post-contingency. However, for all case studies, the fault level at the George Town node as the nearest adjacent node to Burnie was maintained above the minimum of 1,450 MVA.

A3.3.2 Contingencies considered

Screening of the Burnie area credible contingencies for transmission lines was performed. From this screening, the following were the worst-case contingencies and were the focus of the system strength assessment of the Burnie area:

- Contingency 1 – One phase to ground and two phase to ground fault and disconnection of Burnie-Sheffield 220 kV line, cleared within primary protection time.
- Contingency 2 – One phase to ground and two phase to ground fault and disconnection of Transformer at the Burnie 220 kV bus, cleared within primary protection time.
- Contingency 3 – One phase to ground and two phase to ground fault and disconnection of Burnie-Sheffield 110 kV line, cleared within primary protection time.
- Contingency 4 – Two phase to ground fault on the Smithton 110 kV bus and disconnection of Burnie-Smithton 110 kV line, cleared within primary protection time.

A3.4 EMT model setup – Queensland

A3.4.1 Determination of acceptable minimum synchronous generation combinations

Most fault level requirements at Queensland nodes were determined by Stage 1 analysis, however, due to the system strength issues experienced in North Queensland, Stage 2 analysis was completed at the Ross node.

For Stage 1 analysis, different synchronous machine options were considered in North Queensland, in addition to a combination of synchronous generators in Central Queensland. The base case system scenario was set up to include different combinations of synchronous generation in Central and North Queensland, comprising units dispatched more than 99% annually.

For the Stage 2 analysis, a number of synchronous generation dispatch combinations were tested in PSCAD. In order to meet the success criteria following credible contingencies the minimum synchronous unit combinations consist of seven Central Queensland units and at least two hydro generation units in North Queensland. Hence, seven CQ + two hydro units became the base case for analysis in North Queensland.

Table 19 is taken from AEMO's Transfer Limit Advice – System Strength Constraints in North Queensland[136]. The minimum synchronous dispatch scenarios that were studied in EMT are highlighted in red.

[136] Published November 2020, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice.

Table 19 Central and Northern Queensland Synchronous Dispatches studied in EMT

Combination	Stanwell	Callide B	Callide C	Callide B+C	Gladstone	Kareeya	Barron Gorge	NQ Load (MW)
5a	3			2	3	0	0	550
5b	3			2	3	0	0	640
5c	3			2	3	0	0	740
5d	3	1	1		3	0	0	450
5e	3	1	1		3	0	1	650
7c	3	1	1		3	0	0	550
7d	3	1	1		3	0	0	650
8a	2	1	1		3	0	0	450
8a.1	2	1	1		3	0	0	550
8a.2	2	1	1		3	0	0	650
9a	2			1	3	2	0	-
9b	2			1	3	0	0	450
10a	3			2	3	2	0	450
11a	2			2	3	2	1	450
11b	2			2	3	2	0	450
12a	2			1	3	2	0	450
12b	2			1	3	2	0	450

A3.4.2 Contingencies considered

Screening of North and Central Queensland credible contingencies for transmission lines, generators and flexible AC transmission devices (FACTS) was performed. From this screen, it was identified that the worst-case contingency could vary, dependent on synchronous machine dispatch. As such, the fault screening was repeated periodically, but the following were the most frequent worst-case contingencies and were the focus of the system strength assessment of the North Queensland network:

- Contingency 1 – Two phase to ground fault and disconnection of Broadsound – Stanwell 275 kV line, cleared within primary protection time.
- Contingency 2 – Two phase to ground fault and disconnection of Nebo – Strathmore 275 kV line, cleared within primary protection time.
- Contingency 3 – Two phase to ground fault and disconnection of Ross SVC, cleared within primary protection time.
- Contingency 4 – Two phase to ground fault and disconnection of Strathmore SVC, cleared within primary protection time.
- Contingency 5 – Two phase to ground fault and disconnection of Kareeya Power Station units 2 and 4 due to 132 kV transformer trip, cleared within primary protection time.
- Contingency 6 – Two phase to ground fault and disconnection of Townsville Power Station line, if Townsville Power Station is in service, cleared within primary protection time.

- Contingency 7 – Two phase to ground fault and disconnection of Mount Stuart Power Station line, if Mount Stuart Power Station is in service, cleared within primary protection time.

An EMT model of the Queensland region network was benchmarked against AEMO's full four-state EMT model of the NEM network (excluding Tasmania) and was then used to study the North Queensland system strength. As the power system is a complex, dynamic, interconnected system and the configuration and operational conditions in one region impact performance and stability in other regions, South and Central Queensland network and generation was also represented. This revealed that Central Queensland synchronous generators have a significant impact on system strength and required fault levels at the Ross node.

A4. Steady state model setup for system strength

Appendix A4 shows how steady state analysis was completed to assess short-circuit (fault) levels. Once synchronous fault level dispatches are determined for a particular fault level node using the EMT model, steady state analysis is used to determine the requirements for the nodes in each region by applying those dispatches and credible contingencies in the steady state model[137]. The appendix explains how AEMO set up model parameters, lists contingencies considered in the studies, and notes treatment of prior outages.

A4.1 Steady state fault level parameters setup

AEMO is required to assess the system strength requirements across the NEM. Currently, the NER consider fault levels, given in MVA, as the metric for system strength. Fault level is used as a proxy for system strength services in any area of the network for a power system in which the majority of system stabilising services come from synchronous machine technology, as they have a high level of fault current contribution. Thus, when fault level requirements are applied, they are used as a reference for system strength rather than an accurate quantification of the fault level experienced at that particular area of the network.

For this reason, AEMO has established a fault level calculation standard for the purposes of assessing system strength requirements in the NEM. This standard is kept consistent across all regions and is detailed below. AEMO uses a steady state solution to calculate the three phase fault levels, using the following parameters:

- The MVA levels are calculated using the ASCC function. The ASCC method calculates initial AC RMS fault current after the fault inception.
- Flat (1.0 pu) network voltages are applied.
- DC lines and FACTS[138] devices are represented as load.
- Only fault level from synchronous machines is considered.
- Subtransient machine impedance is used rather than transient machine impedance. This is because the overall accuracy compared with the EMT model at 100 ms after the fault inception is quite good when the fault currents are calculated with the generator subtransient reactance. The fault current contribution from synchronous machines will decay, and the decayed fault current can be calculated using generator transient reactance. However, due to different machine characteristics, the timeframe for transient reactance to take effect is not the same for all generating units. Thus, using transient reactance to assess system strength requirements could introduce inconsistencies.
- P and Q of synchronous machines are set to zero, as fault current contribution should remain independent of a machine's output for a certain dispatch.
- Inverter-based generators are set to out of service.
- Transformer tap ratios are set to unity and phase angle is set to zero.
- Line charging, shunt and load values are set to zero.

[137] Note the continency that results in the lowest fault level in these steady state studies is not always the same as the critical contingency in the EMT studies.

[138] FACTS – Flexible AC Transmission System

The studies have been undertaken to 2030, utilising the outcomes of the time-sequential short-term market modelling. Further information on the market modelling assumptions is available in Appendix A2.5.

A4.2 Contingencies considered in the studies

In assessing the requirements for each node in the EMT model, AEMO considers multiple contingencies and generation combinations to determine the minimum acceptable generation combinations that meet the success criteria. These combinations are then applied in steady state analysis, and short-circuit analysis is undertaken to identify the critical credible contingency which gives the minimum fault level at the fault level node utilising the parameters detailed above. Contingencies in Table 20 have been identified as worst-case contingencies for the respective nodes, so return the system strength minimum fault level requirement.

Table 20 Identified critical contingencies for fault level nodes in each region

Region	Fault level node	Worst case contingency
New South Wales	Armidale 330 kV	Armidale – Tamworth 330 kV feeder
	Darlington Point 330 kV	Darlington Point to Wagga 330 kV feeder
	Newcastle 330 kV	Newcastle -Liddell 330 kV feeder
	Sydney West 330 kV	Sydney West – Sydney North 330 kV feeder
	Wellington 330 kV	Wellington – Wollar 330 kV feeder
Queensland	Greenbank 275 kV	Millmerran generating unit
	Gin Gin 275 kV	Calliope River – Woolooga tee Gin Gin 275 kV feeder
	Lilyvale 132 kV	Lilyvale 275/132 kV transformer
	Ross 275 kV	Ross – Strathmore 275 kV feeder
	Western Downs 275 kV	Braemar 330/275 kV transformer
South Australia	Davenport 275 kV	Davenport synchronous condenser
	Para 275 kV	Robertstown synchronous condenser
	Robertstown 275 kV	Robertstown synchronous condenser
Tasmania	Burnie 110 kV	Burnie – Sheffield 220 kV feeder
	George Town 220 kV	System intact
	Risdon 110 kV	System intact
	Waddamana 220 kV	System intact
Victoria	Dederang 220 kV	South Morang 500/220 kV transformer
	Hazelwood 500 kV	Hazelwood – South Morang 500 kV feeder*
	Moorabool 220 kV	Moorabool 500/220 kV transformer
	Red Cliffs 220 kV	Red Cliffs to Buronga and Red Cliffs to Carpwarp 220 kV feeders
	Thomastown 220 kV	Thomastown – Keilor 220 kV feeder

* Consideration has also been given to operational switching of one Hazelwood – Rowville 500 kV for the purposes of voltage control

A4.3 Prior outages modelled

Operational switching is used in some regions to manage high system voltages, with this often coinciding with a lower number of synchronous generators online. AEMO has considered where operational switching is likely to impact on the system strength conditions.

In December 2019, AEMO, in its role as the Victorian jurisdictional planning body, published the Victorian Reactive Power Support Project Assessment and Conclusions Report (PACR). The PACR identified the preferred option as the installation of 1 x 220 kV 100 MVAr shunt reactor at Keilor and 2 x 220 kV 100 MVAr shunt reactors at Moorabool.

The installation of these reactors is expected to reduce the number of lines required to be switched during low demand periods, and as a result, in these studies only the Hazelwood – South Morang 500 kV line 1 is switched for voltage control during light loading conditions.

A5. EMT model setup for inertia

This appendix notes the assessment methodology applied for the EMT studies used to perform the inertia requirements declared in this report, and the specific model set-up parameters for Queensland and Victoria.

A5.1 Assessment methodology

AEMO conducted 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. 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.

Assumptions

Assumptions for the EMT model include:

- Output from online generation can be reduced to limit the size of the contingency. However, this reduction should not compromise lower frequency control capability of the generator. The generator should have sufficient range to reduce their generation in response to high frequency events.
- Registered FCAS for large generators and loads is modelled in accordance with their individual registrations[139]. Additionally, when a generator is online, it must provide at least its registered FCAS[140].
- Disconnection of DER, predominantly distributed PV, as a result of a nearby disturbance is modelled as an increase in the size of the contingency. The amount of DER disconnection outlined in the sections below is currently determined by PSS/E studies, rather than being determined natively in PSCAD. The levels of DER disconnection have been taken from the 2020 ESOO[141]. It is noted that DER disconnection is assumed to not to increase beyond 2021 as updated inverter requirement standards under AS4777.2[142] will allow for remote disconnection of newly connected DER.
- Generators online and not registered for providing frequency control services are assumed to provide some amount of frequency control with a 5% droop. This is as a result of the primary frequency response rule change[143].
- Utility-scale battery systems dispatched do not provide inertia. However, they are able to provide FFR that may reduce the inertia requirement in a region, and this capability is modelled in this assessment.

Determination of inertia requirements

EMT analysis was completed to determine the minimum generation dispatch that provides sufficient frequency control and inertia within a region. The minimum generation dispatch would need to ensure that the system remains in a satisfactory operating state following a credible contingency.

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[139] AEMO, NEM Registration and Exemption List, November 2020, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration.

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

[141] 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.

[142] Australian Standards, Grid Connection of energy system via inverters, Part 2, Inverter requirements AS/NZS 4777.2:2015 - Standards Australia.

[143] AEMC, Mandatory Primary Frequency Response, March 2020, at https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

Several contingencies are studied per islanded region and the secure level of inertia is determined based on the worst-case contingency identified throughout the modelling process. The minimum operating level of inertia is equivalent to the inertia associated with a generation dispatch based on the minimum system strength requirements for a region. Provided the difference between this dispatch model and the secure level of inertia can met by fast start generation within 30 minutes, then the minimum threshold level of inertia is determined by this dispatch model. If this condition cannot be met the minimum threshold level of inertia is increased until this condition is satisfied.

Success criteria

The success criteria for determining if an islanded region returns to a satisfactory operating state[144] following a credible contingency includes:

- Frequency is maintained within the relevant frequency bands for each specific operating condition studied[145].
- Occurrence of a credible contingency does not result in activation of automatic load or generation shedding schemes and consequent load or generation loss[146].
- The high voltage transmission network voltages across the region return to nominal voltages[147].
- All online generators return to steady-state conditions following fault clearance, unless they are intentionally tripped as a part of the contingency.

Regions assessed in this report

For this report, the inertia requirements for Victoria and Queensland have been assessed. The following sections of this appendix document the contingencies studied and the associated assumed levels of DER disconnection and FCAS response for these regions. For the other regions the following is noted:

- South Australia – in August 2020, AEMO published the Notice of South Australia Inertia Requirements and Shortfall[148] which employed a similar EMT study process to determine the minimum and secure operating levels of inertia. Due to the immediacy of the secure operating level of inertia identified in the notice, a spectrum of fast frequency response and synchronous inertia combinations were proposed to address the shortfall up to 2021-22. Shortfall projections beyond this period were not declared due to the uncertainty in the size of coincident distributed PV and load tripping in response to credible contingencies. The outcomes of this analysis have been reported in the main body of this report.
- Tasmania – in November 2019, AEMO published the Notice of Inertia and Fault Level Shortfalls in Tasmania[149]. AEMO used dynamic power system analysis in determining the minimum and secure operating levels of inertia. Following this declaration, TasNetworks (as the responsible TNSP) contracted Hydro Tasmania to provide inertia network services and system strength services in sufficient quantity to meet the declared shortfall volumes for a four-year period. These services were made available to AEMO on 15 April 2020[150]. The outcomes of this analysis have been reported in the main body of this report.
- New South Wales – the likelihood of New South Wales islanding is considered remote, and currently it hosts a large amount of synchronous generation. Based on these two factors, no EMT simulation was carried out for New South Wales for this assessment. Rather, the inertia requirements for New South

[144] Clause 4.2.2 of the NER

[145] For the purpose of this work only arresting band is considered which is in line with 2018 Inertia Requirements.

[146] AEMO, Inertia Requirements Methodology, July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

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

[148] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en.

[149] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

[150] TasNetworks, Annual Planning Report 2020, at https://www.tasnetworks.com.au/config/getattachment/4a3679b2-d65a-4c8e-b2f6-34920dbb2045/tasnetworks-annual-planning-report-2020.pdf.

Wales are taken from the 2018 Inertia Requirements and Shortfalls[151] assessment used a single mass model (SMM) to determine the specific requirements.

A5.2 EMT model setup and requirements – Queensland

The specific model setups for Queensland and contingencies studied are detailed in this section.

Net maximum DER disconnection

The maximum net generation loss of distributed DER modelled for each year in the five-year outlook in the Queensland region is shown in Table 21.

Table 21 Size of DER disconnection for the Queensland region

Year	DER disconnection (MW)*
2021	50
2022	130
2023	130
2024	130
2025	130

* Note the maximum net DER disconnection figures indicated above only apply to a subset of contingencies studied as indicated in the following sections.

Registered 6 second FCAS for Queensland

The registered 6 second FCAS modelled for generators and loads in the Queensland region is in accordance with the NEM Registration and Exemption List[152].

Contingencies and inertia requirements

The generation combinations and contingencies, including DER contingency size, considered for the Queensland region and resulting inertia requirements are shown in Table 22 for 2021 and Table 23 for 2022 onwards. As the DER contingency size is not expected to grow beyond 2022, the requirements are expected to remain the same.

Table 22 2021 Queensland inertia requirements

Synchronous Generator Dispatch	Contingency	Total contingency (MW)	F_min / F_max	Secure level of inertia (MWs)
3GLA+3STA+2TAR+1CALB+TARN+KOG+MIL+3KAR	Kogan	320	49.10	14,800
3GLA+3STA+2TAR+1CALB+TARN+KOG+MIL+3KAR	Millmerran	300	49.00	14,800
3GLA+3STA+2TAR+1CALB+TARN+KOG+MIL+3KAR	Stanwell	240	49.09	14,800
3GLA+3STA+2TAR+1CALB+TARN+KOG+MIL+3KAR	Tarong	270	49.23	14,800
3GLA+3STA+2TAR+1CALB+TARN+KOG+MIL+3KAR	Tarong	320	49.00	14,800

151 At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

152 At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration.

Synchronous Generator Dispatch	Contingency	Total contingency (MW)	F_min / F_max	Secure level of inertia (MWs)
3GLA+3STA+2TAR+1CALB+TARN+KOG+MIL+3KAR	Boyne Island	390	50.90	14,800
3GLA+3STA+2TAR+1CALB+TARN+KOG+2KAR	Stanwell	240	49.07	13,600
3GLA+3STA+2TAR+1CALB+TARN+KOG+2KAR	Kogan	320	49.08	13,600
3GLA+3STA+3TAR+1CALB+KOG+2KAR	Stanwell	240	49.10	13,000
3GLA+3STA+3TAR+1CALB+KOG+2KAR	Kogan	320	49.07	13,000
3GLA+3STA+3TAR+1CALB+KOG+2KAR	Tarong	260	49.20	13,000
3GLA+3STA+3TAR+1CALB+KOG+2KAR	Tarong	310	49.05	13,000
4GLA+2STA+2TAR+1CALB+TARN+KOG+2KAR	Stanwell	215	40.12	13,700
4GLA+2STA+2TAR+1CALB+TARN+KOG+2KAR	Kogan	320	49.13	13,700
4GLA+2STA+2TAR+1CALB+TARN+KOG+2KAR	Tarong	290	49.10	13,000
4GLA+2STA+2TAR+1CALB+TARN+KOG+2KAR	Boyne Island	390	50.95	13,000
4GLA+1STA+3TAR+2CALB+TARN+KOG+2KAR	Tarong	280	49.05	14,700
4GLA+1STA+3TAR+2CALB+TARN+KOG+2KAR	Kogan	280	49.07	14,700
4GLA+1STA+3TAR+2CALB+TARN+KOG+2KAR	Stanwell	190	49.10	14,700
4GLA+1STA+3TAR+2CALB+TARN+KOG+2KAR	QNI-Import	270	49.05	14,700
4GLA+1STA+3TAR+2CALB+TARN+KOG+2KAR	Boyne Island	390	50.99	14,700
4GLA+1STA+3TAR+2CALB+TARN+KOG+2KAR	QNI-Export	320	50.95	14,700

Table 23 2022 Queensland inertia requirements

Synchronous Generator Dispatch	Contingency	Total contingency (MW)	F_min/ F_max	Secure level of inertia (MWs)
3GLA+3STA+2TAR+1CALB+TAR**N+KOG+MIL+3KAR**	Tarong	305	49.05	14,800
4GL+1ST+3TR+2CB+TN+KG+2KA	Tarong	290	49.10	14,700

Note from 2022 onwards the DER contingency size does not grow. Assuming no significant changes in network such as major generator retirements, new interconnectors developed, then the inertia requirements for the remainder of the five-year outlook (from 2022 onwards) are derived from this table.

A5.3 EMT model setup and requirements – Victoria

The specific model setup for Victoria and contingencies studied are detailed within this section.

Net maximum DER disconnection

The maximum net generation loss of distributed DER modelled for each year in the five-year outlook in the Victoria region is shown in Table 24.

Table 24 Size of DER disconnection for the Victoria region

Year	DER disconnection (MW)*
2021	90
2022	250
2023	250
2024	250
2025	250

* Note the maximum net DER generation loss figures indicated above only apply to a subset of contingencies studied as indicated in the following sections.

Registered 6 second FCAS for Victoria

The registered 6 second FCAS modelled for generators and loads in the Victoria region is modelled in accordance with NEM Registration and Exemption List[153]. Additionally, the following assumptions have been made in this assessment:

- The plant is not registered to provide frequency control services. Droop of 5% is assumed considering the preliminary Primary Frequency Response Rule[154] change.
- 60 MW of 6 sec FCAS is assumed available from loads, based on historical information.

Contingencies and inertia requirements

The contingencies considered for the Victoria region and resulting inertia requirements are shown in Table 25 for 2021 and Table 26 for 2022 onwards. As the DER contingency size is not expected to grow beyond 2022, the requirements are expected to remain the same.

Table 25 2021 Victoria inertia requirements

Synchronous Generator Dispatch	Contingency	Total contingency (MW)	F_min/ F_max	Secure level of Inertia (MWs)
2xLYB + 3xYPS	Loy-Yang B	230	48.75 Hz	7,750
2xLYB + 3xYPS	Loy-Yang B	410	40.00 Hz	7,750
2xLYB + 3xYPS + NPS	Loy-Yang B	370	47.50 Hz	10,550
2xLYB + 3xYPS + NPS	Loy-Yang B	290	48.50 Hz	10,550
2xLYB + 3xYPS + NPS	Loy-Yang B	410	47.20 Hz	10,550
2xLYB + 3xYPS + NPS + 1xLYA	Loy-Yang B	390	48.30 Hz	12,520
2xLYB + 3xYPS + NPS + 1xLYA	Loy-Yang B	410	48.63 Hz	12,520
2xLYB + 3xYPS + NPS + 2xLYA	Loy-Yang B	410	47.40 Hz	12,520
2xLYB + 3xYPS + NPS + 2xLYA	Loy-Yang B	410	48.90 Hz	14,490
2xLYB + 3xYPS + NPS + 2xLYA	Loy-Yang B	410	49.02 Hz	14,490
2xLYB + 3xYPS + NPS + 2xLYA	Loy-Yang B	410	49.17 Hz	14,490

[153] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration.

[154] AEMO, Primary Frequency Response Requirements (proposed), August 2019, at https://www.aemc.gov.au/sites/default/files/2019-10/AEMO%20-%20Primary%20frequency%20response%20requirements%20V1.1%20-%20clean.PDF.

Synchronous Generator Dispatch	Contingency	Total contingency (MW)	F_min/ F_max	Secure level of Inertia (MWs)
2xLYB + 3xYPS + NPS + 2xLYA	Loy-Yang B	410	49.10 Hz	14,490
2xLYB + 3xYPS + NPS + 2xLYA	Loy-Yang A	460	49.07 Hz	14,490
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	510	48.24 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	510	48.51 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	510	49.00 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	510	49.10 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	470	48.97 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	470	49.09 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	460	49.10 Hz	13,890
2xLYB + 3xYPS + NPS + 1xMOPS + 2BOG + 2McKay	Loy-Yang B	460	48.90 Hz	13,270
2xLYB + 3xYPS + NPS + 1xMOPS + 2BOG + 2McKay	Loy-Yang B	460	49.10 Hz	13,270
2xLYB + 3xYPS + NPS + 1xMOPS + 2BOG + 2MK + DM	Loy-Yang B	460	49.08 Hz	13,930
2xLYB + 2xYPS + NPS + 2xMOPS	Loy-Yang B	470	48.67 Hz	12,700
2xLYB + 2xYPS + NPS + 2xMOPS	Loy-Yang B	460	49.10 Hz	12,700
2xLYB + 3xYPS + 2xBOG + 2xMckay +2xMOPS	Loy-Yang B	460	49.08 Hz	12,200
2xLYB + 3xYPS + NPS + 2xLYA	APD	470	50.70 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	APD	470	50.95 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	APD	470	50.85 Hz	13,890

Table 26 2022 Victoria inertia requirements

Synchronous Generator Dispatch	Contingency	Total contingency (MW)	F_min/ F_max	Secure level of Inertia (MWs)
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	680	48.97 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	670	48.80 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	630	48.86 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	630	48.94 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	630	49.02 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	642	49.06 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	635	49.10 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	625	49.10 Hz	13,890

Synchronous Generator Dispatch	Contingency	Total contingency (MW)	F_min/ F_max	Secure level of Inertia (MWs)
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	620	49.10 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	620	49.14 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	620	49.10 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	620	49.03 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	620	49.08 Hz	13,890
2xLYB + 3xYPS + NPS + 2xMOPS	Loy-Yang B	620	49.05 Hz	13,890
6xLYB + 4xYPS + NPS + 2xMOPS	Loy-Yang B	620	48.92 Hz	23,500
6xLYB + 4xYPS + NPS + 2xMOPS	Loy-Yang B	620	49.04 Hz	23,500

Notes:

- In the cases #01 to #09 a 0.15 Hz dead-band has been used for Moorabool BESS, while in the cases #10 to #14 a 0.015 Hz dead-band is used for Moorabool BESS. Also, in cases #15 and #16 Moorabool BESS has not been considered.
- In cases #12, #13, #14, the fast frequency response capability of Moorabool BESS has been limited to 220 MW, 250 MW, and 200 MW, respectively.
- From 2022 onwards the DER contingency size does not grow. Assuming no significant changes in network such as major generator retirements, new interconnectors developed, then the inertia requirements for the remainder of the five-year outlook (from 2022 onwards) are derived from this table.