

# Appendix A2 – Network Requirements

2025

An appendix to the Transition Plan for  
System Security





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

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

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

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

## Important notice

### Purpose

The purpose of this publication is to report on:

- the system strength nodes and system strength standards (minimum and efficient levels) for the coming decade for the National Electricity Market;
- the boundaries of the inertia sub-networks, the inertia requirements for each inertia sub-network for the coming 10-year period for the National Electricity Market, the assumptions, considerations and matters that AEMO has taken into account to determine the inertia requirements and the binding inertia requirements; and
- the Network Support and Control Ancillary Service gaps identified by AEMO over a five-year outlook period.

AEMO publishes this publication in accordance with clauses 5.20.3, 5.20.5, 5.20.7 and 11.143.14(f) of the National Electricity Rules. This publication is generally based on information available to AEMO as at October 2025 unless otherwise indicated.

### Disclaimer

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### Version control

Version	Release date	Changes
1.0	1 December 2025	First release

# Summary

AEMO has a range of operational system security needs and capabilities to be planned and delivered across the NEM over the coming five years. Declining minimum operational demand, reduced operation of synchronous generators, and rapid uptake of VRE resources have combined to create an increased need for essential power system services.

This appendix is part of a broader *Transition Plan for System Security* (TPSS) and fulfills AEMO's obligation to publish the annual system strength, inertia and network support control ancillary service (NSCAS) reports. The *Transition Plan for System Security* works to ensure the power system can continue to operate securely and reliably as the energy transition continues at pace. While network businesses can already act through their existing planning processes, AEMO's work to declare NSCAS gaps remains an important safety net for power system security.

## AEMO has explored a broad range of power system needs in the NSCAS assessments

To capture these emerging needs, this appendix explores a range of potential power system requirements over the next five years. It includes a regional assessment of the system's ability to stay within thermal and voltage control limits, maintain adequate reactive margins, limit rapid voltage changes, and to provide sufficient options to return to a secure operating state following a credible contingency event. This appendix also contains an assessment of system strength and inertia deficits in the near term, as these two core system security requirements continue to grow in importance and significance for the power system.

These 2025 system strength and inertia assessments have confirmed the importance of delivering system strength and inertia solutions in tandem, as both these requirements become increasingly onerous.

## AEMO has assessed risks, shortfalls and NSCAS gaps across all regions

Based on the 2025 NSCAS studies, AEMO has identified system strength and inertia deficits, along with voltage control gaps and emerging risks across several regions. While most of these identified risks have solutions underway, interim measures such as contracting synchronous plant are likely to be required until permanent solutions are installed.






A summary of regional findings is presented in **Table 1**, and AEMO will continue to work closely with the relevant network businesses to track the magnitude, timing, and remediation associated with each.

## AEMO has confirmed system strength and inertia requirements for all regions

AEMO has confirmed the system strength nodes, and their minimum fault level requirements continue to be maintained at the present values in the 2025 report across all regions. AEMO has also updated the IBR projections in each region used to determine the efficient level of system strength, based on the latest available draft information from the 2026 ISP.

Additionally, AEMO has confirmed that the inertia requirements for all regions remain unchanged this year, with a minor update for Queensland.

**Table 1 Summary of network requirements, to be addressed by transmission network service providers**

Region	TNSP requirements
<p><b>New South Wales</b> (Transgrid)</p> 	<p><b>System strength deficits across New South Wales have again been confirmed from 2027-28 with the currently announced Eraring Power Station retirement date.</b> In response, Transgrid is expediting the procurement of synchronous condensers with support from the New South Wales government; however, additional measures are necessary to ensure ongoing power system security. Contracting for these services may be required prior to 2027-28, depending on market conditions.</p> <p><b>Inertia deficits are also forecast from 2027-28</b>, underscoring the need for further action by Transgrid to ensure sufficient inertia is available from 2 December 2027. The synchronous condensers being procured will include flywheels to deliver inertia, although deficits are currently forecast until those assets are installed.</p> <p><b>No gaps related to thermal loading or voltage control have been identified</b> under current demand scenarios. Nonetheless, several emerging network risks remain for electricity supply around Sydney during periods of peak demand, particularly if expected generation and network developments, including actionable projects, do not proceed as planned.</p>
<p><b>Queensland</b> (Powerlink)</p> 	<p>There are <b>emerging system strength needs in Queensland from 2027-28, with solutions underway.</b> These needs are expected to be fully addressed by Powerlink’s planned system strength solutions.</p> <p>Two <b>emerging inertia needs have been identified, with remedial measures underway.</b> These will be fully met through the installation of synchronous condensers, the existing clutch solution at Townsville Power Station, and expected contributions from existing grid-forming inverters.</p> <p><b>The successful delivery of the Gladstone Project transmission augmentation is essential</b> for managing emerging thermal and voltage risks following the retirement of Gladstone power station. Powerlink has already commenced work on this project, with regulatory approval schedule for assessment in early 2026.</p>
<p><b>South Australia</b> (ElectraNet)</p> 	<p><b>No system strength deficits have been identified.</b></p> <p><b>No inertia deficits have been identified.</b></p> <p><b>The previously declared voltage control gap is actively being addressed.</b> ElectraNet is resolving this issue through the installation of new switched reactors in the Adelaide and South East regions. Three of the six reactors have already been installed, with the remaining three scheduled to be operational by October 2027.</p>
<p><b>Tasmania</b> (TasNetworks)</p> 	<p>AEMO has confirmed <b>projected system strength deficits across Tasmania.</b> TasNetworks is seeking to contract with existing assets to manage these requirements.</p> <p><b>Inertia deficits have also been identified.</b> Contracts are being explored alongside system strength remediation.</p> <p><b>No gaps have been identified in relation to thermal loading or voltage control</b> at this time.</p>
<p><b>Victoria</b> (VicGrid)</p> 	<p><b>Emerging system strength needs are anticipated from 2028-29, primarily associated with the planned closure of Yallourn Power Station.</b> VicGrid is actively progressing solutions to address these needs, including the installation of synchronous condensers and potentially contracting with generation capable of operating in synchronous condenser mode.</p> <p>An <b>inertia deficit has also been confirmed from 2027-28.</b> While the synchronous condensers scheduled for installation will partially mitigate this need, VicGrid may need to take additional measures to ensure that sufficient inertia is available in Victoria from 2 December 2027.</p> <p><b>AEMO confirmed the existing voltage control and thermal loading risks at Deer Park.</b> Control schemes are currently in place to manage these operational challenges until network augmentations can be delivered. Overloading risks were also identified for supply into Melbourne following the Yallourn retirement. To address these issues, VicGrid is investigating solutions through both the eastern metropolitan grid reinforcement and western metropolitan grid reinforcement projects.</p>

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## A2.1 Overview

This appendix contains system security assessments conducted to address the security reporting obligations AEMO has under section 5.20.3, 5.20.5, 5.20.7 and 11.143.14(f) of the NER. These obligations help to ensure that the power system is being planned to manage power system security and reliability. There are three main components:

- **Network support and control ancillary services** – these assessments evaluate whether any additional reliability or security services are needed, as well as if there are any services which could increase net market benefit.
- **Inertia requirements** – each year, AEMO assesses and publishes the regional requirements for inertia to allow subsequent delivery and maintenance by the Inertia Service Provider in each region.
- **System strength requirements** – each year, AEMO assesses and publishes the regional requirements for system strength to allow subsequent delivery and maintenance by the system strength service provider (SSSP) in each region. These requirements cover the *minimum three phase fault level* to ensure power system security, and the *efficient level of system strength* to facilitate future IBR.

### A2.1.1 NSCAS regulatory obligations

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

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

AEMO assesses the need for these services annually and declares NSCAS gaps where it identifies an unmet need. Gaps generally relate to voltage control, system stability, inertia, system strength, and thermal limits, but can include other aspects that are required for operating a secure power system.

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

#### A2.1.1.1 Reliability and security ancillary services (RSAS)

To identify RSAS gaps, AEMO considers the ability of the power system to maintain a secure operating state during system normal conditions; that is, the ability of the system to land in a satisfactory operating state following a credible contingency or protected event. RSAS can include any:

- **Non-market ancillary service (NMAS)** required to maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard. Where AEMO has identified an NMAS issue which the relevant TNSP is progressing a solution to address AEMO may flag this as an ‘emerging risk’ rather than an ‘NMAS gap’.
- **Inertia network service** necessary to meet an inertia requirement, where the requirement has been revised to a level that exceeds the currently applicable binding inertia requirements.

- **System strength service** necessary to meet a minimum three phase fault level, where that minimum has been revised to a level that exceeds the currently applicable system strength requirement.

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

#### A2.1.1.2 Market benefits ancillary services (MBAS)

To identify MBAS gaps, AEMO considers whether positive net market benefits could be delivered by relieving high-impact network constraints. AEMO reviews existing constraint statistics, to identify any constraints that bound for at least one hour in the previous calendar year and had a total marginal cost of at least \$60,000. AEMO may also consider specific constraints nominated by participants or those forecast to be significant through other power system planning and operational activities. Summated marginal value is a proxy for congestion (and always an upper bound) over a given period. TNSPs undertake cost benefit analysis in assessing opportunities for works that would alleviate a constraint with high marginal value over a given period.

#### A2.1.2 Inertia regulatory obligations

AEMO is responsible for determining, publishing and maintaining the NEM inertia requirements in accordance with the NER. AEMO's obligation to prepare and publish the inertia report is established under NER 5.20.5. The rule requires AEMO to determine, by 1 December each year, the forecast inertia requirements for the NEM over a 10-year outlook period (commencing 2 December). This is achieved by applying the inertia requirements methodology established under NER 5.20.4, which sets out the approach AEMO uses to assess the secure and satisfactory levels of inertia required in each sub-network and across the NEM.

These requirements underpin AEMO's responsibility to maintain a secure and reliable power system. With increasing integration of IBR, system inertia across the NEM is decreasing and becoming more widely dispersed due to the displacement of large synchronous generators by distributed, inverter-based generation.

In accordance with NER 5.20B.2(b) and the latest *Inertia Requirements Methodology*, the 2025 inertia report must include AEMO's 10-year forecast from December 2025 to December 2035 inclusive of the following matters for each inertia sub-network:

- **Satisfactory inertia level**, being the minimum level of inertia required to operate an inertia sub-network in a satisfactory operating state when the inertia sub-network is islanded.
- **Secure inertia level**, being the minimum level of inertia required to operate an inertia sub-network in a secure operating state when the inertia sub-network is islanded.
- **System-wide inertia level**, being the mainland inertia required to operate the mainland regions of the NEM securely.
- **Inertia sub-network allocation**, being the portion of the system-wide inertia level allocated to that inertia sub-network.
- **Inertia sub-network islanding risk**, being the likelihood of a sub-network islanding, and whether the secure inertia level is met if it does.

If AEMO becomes aware of a material change to the power system likely to affect the inertia requirements, where the timing, occurrence or impact of the change was unforeseen, AEMO must, as soon as reasonably practicable, revise and publish its determination of the relevant forecast.

### A2.1.2.1 Inertia service providers are required to meet the binding inertia requirements

While AEMO is required to forecast the *inertia requirements* over a 10-year period under NER 5.20B.2(b), inertia service providers are required to make available inertia services to meet the **binding inertia requirements**. The *binding inertia requirements* are defined in NER 5.20B.2(g) as the forecast *inertia requirements* three years prior. For example, the *binding inertia requirements* for 2027 are the forecast *inertia requirements* published in the 2024 *Inertia Report*, while the *binding inertia requirements* for 2028 are the forecast *inertia requirements* published in the 2025 *Inertia Report* (this Appendix 3 of the 2025 TPSS).

Sometimes AEMO may publish a revision to one or more of the *inertia requirements* within three years, for example, a revision of the forecast *inertia requirements* for 2027 published in this 2025 inertia report. Inertia service providers under NER 5.20B.2(h) may – but are not required to – make available inertia services to meet such revised requirements where they have been increased.

### A2.1.2.2 Transitional inertia shortfalls apply until 2 December 2027

NER 11.168.9 provides transitional rules leading up to the start of a new inertia planning framework under the *Improving security frameworks for the energy transition* (2024) (ISF) rule<sup>1</sup> on 2 December 2027. Prior to 2 December 2027, if there is an existing declared inertia shortfall then AEMO may adjust this deficit in its annual inertia report.

Both Queensland and Tasmania have existing inertia shortfalls published in the previous 2024 *Inertia Report* which have been updated in this 2025 report. Inertia shortfalls are not applicable during the inertia framework transition period for other regions because no inertia shortfalls were declared for those regions in the 2024 *Inertia Report*, and the transitional rules do not permit new inertia shortfalls to be declared before 2 December 2027.

Shortfalls will no longer apply from 2 December 2027. All inertia service providers will need to ensure that sufficient inertia services are available from this date to meet the secure inertia level – that is, the minimum level of inertia required to operate an inertia sub-network in a secure operating state when the inertia sub-network is islanded.

### A2.1.2.3 Projected inertia adequacy is assessed through the NSCAS framework

The ISF rule requires AEMO to assess inertia network services in its annual NSCAS assessment. From 1 December 2024, AEMO may only declare an inertia NSCAS gap if it occurs because AEMO has increased the inertia requirements within a three-year window<sup>2</sup>. If AEMO has not increased the inertia requirements or a potential gap is identified outside the three-year window, this is highlighted as an ‘inertia deficit’ rather than an inertia NSCAS gap.

An inertia deficit does not trigger any procurement or regulatory action. It is reported for visibility only, as the conditions for declaring an NSCAS gap have not been satisfied. While no new obligations arise for AEMO or the TNSPs in response to an inertia deficit<sup>3</sup>, the TNSP has ongoing obligations to plan for the inertia requirements set out in this report.

<sup>1</sup> At <https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition>.

<sup>2</sup> NER Chapter 10, definition of ‘NSCAS gap’ and ‘NSCAS need’.

<sup>3</sup> AEMO recently submitted a rule change request to provide firmer oversight of TNSP planning, with forecast shortfalls for system strength and inertia able to be declared by AEMO which trigger obligations. See <https://www.aemc.gov.au/rule-changes/security-framework-enhancements> for further details.

### A2.1.3 System strength regulatory obligations

AEMO is responsible for determining, publishing and maintaining the NEM *system strength requirements* in accordance with the NER. AEMO's obligation to prepare and publish the system strength report is established under NER 5.20.7. This requires AEMO to determine, by 1 December each year, the forecast system strength requirements for the NEM over a 10-year outlook period (commencing 2 December). This is achieved by applying the system strength requirements methodology established under NER 5.20.6, which sets out the approach AEMO uses to determine system strength nodes, minimum *three phase fault level*, and projected IBR and Schedule 5.3a plant<sup>4</sup>.

These requirements underpin AEMO's responsibility to maintain a secure and reliable power system. As large synchronous generators (such as coal-fired generators) age and approach retirement, and renewable energy resources are increasingly integrated, system strength across the NEM is decreasing and becoming more widely dispersed.

In accordance with NER 5.20C.1(c), the 2025 system strength report must include AEMO's forecast of the following matters for each *system strength node*:

- **Minimum fault level for use in real-time operations**, being the minimum *three phase fault level* applicable for the purposes of NER 4.2.6(g), 4.4A.3(b)(4) and 4.6.1(b) for the following one year commencing 2 December. This can be found in Section A2.9.
- **Minimum fault level for use in planning**, being the minimum *three phase fault level* applicable for the purposes of NER S5.1.14(b)(1) for the following 10 years commencing 2 December.
- **IBR forecast**, being the level and type of *IBR* and *schedule 5.3a plant* projected by AEMO for the *system strength node* for the purposes of NER S5.1.14(b)(2) for the following 10 years commencing 2 December.

If AEMO becomes aware of a material change to the power system likely to affect the system strength requirements, where the timing, occurrence or impact of the change was unforeseen, AEMO must, as soon as reasonably practicable, revise and publish its determination of the minimum fault level or IBR forecast.

#### A2.1.3.1 System strength planning has 'minimum' and 'efficient' requirements

System strength can broadly be described as the ability of the power system to maintain a stable voltage waveform at any given location in the power system, both during steady state operation and following a disturbance.

The system strength planning framework introduced in the *Efficient management of system strength on the power system* (2021) rule<sup>5</sup> in NER S5.1.14 requires System Strength Service Providers (SSSPs) to plan to make system strength services available to meet:

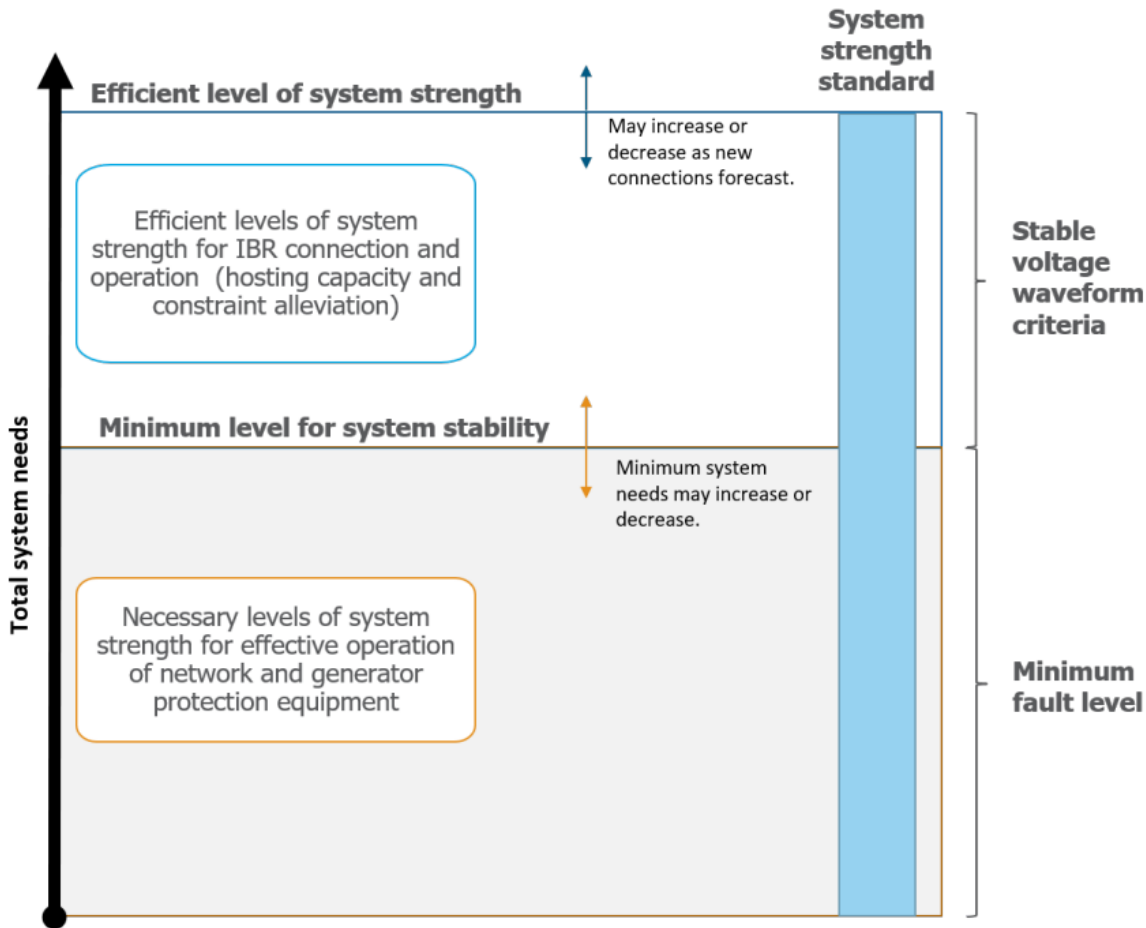
- **The minimum level**, being the *minimum three phase fault level* required for power system security at each system strength node (S5.1.14(b)(1)).
- **The efficient level**, being a requirement to maintain stable voltage waveforms at connection points to host levels of IBR and schedule 5.3a plant forecast by AEMO (as the national transmission planner) at each system strength node (S5.1.14(b)(2)).

<sup>4</sup> Defined in the NER as a system comprising high voltage direct current technology with a *power transfer capability* of 5 MW or more, used to transfer electricity to, from or between one or more alternating current *networks* (or parts of an alternating current *network*) of a *Network Service Provider*.

<sup>5</sup> At <https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system>.

A description of ‘stable voltage waveforms’ for the purpose of meeting the efficient system strength requirements is provided in AEMO’s *System Strength Requirements Methodology*<sup>6</sup>.

Figure 1 Minimum and efficient levels of system strength



Source: AEMC National Electricity Amendment (Efficient Management Of System Strength On The Power System) Rule 2021 Final Determination.

### A2.1.3.2 System Strength Service Providers are required to meet the system strength standard specification

While AEMO is required to forecast the planning *system strength requirements* over a 10-year period under NER 5.20C.1(c)(2), *System Strength Service Providers* are required to make available system strength services to meet the **system strength standard specification**. The *system strength standard specification* is defined in NER S5.1.14(a) as the forecast *system strength requirements* three years prior. For example, the *system strength standard specification* for 2027 is the forecast *system strength requirements* published in the 2024 *System Strength Report*, while the *system strength standard specification* for 2028 is the forecast *system strength requirements* published in the 2025 system strength report (this Appendix A2 of the TPSS).

<sup>6</sup> At [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/system-strength-requirements-methodology-v21.pdf?rev=c717e686b58e4b0eb131c05ca6583aa6&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/system-strength-requirements-methodology-v21.pdf?rev=c717e686b58e4b0eb131c05ca6583aa6&sc_lang=en).

The *system strength standard specification* is also sometimes referred to as the *binding system strength requirements* in the NER. Sometimes AEMO may publish a revision to one or more of the *system strength requirements* within three years, for example, a revision of the forecast *system strength requirements* for 2027 published in this report. System Strength Service Providers under NER 5.20C.1(f) may – but are not required to – make available system strength services to meet such revised requirements where they have been increased.

### A2.1.3.3 System strength shortfalls no longer apply

System strength shortfalls do not apply under the new system strength planning framework introduced in the *Efficient Management of System Strength on the Power System* (2021) rule change<sup>7</sup>. Transitional rules are specified under NER 11.143, which required AEMO to continue to assess and declare system strength shortfalls during the transition period until 1 December 2025. System strength shortfalls will no longer apply from this 2025 report, as the transition period has now finished. All System Strength Service Providers must ensure that sufficient system strength services are available from 2 December 2025 to meet the *system strength standard specification*.

### A2.1.3.4 Projected minimum three phase fault level adequacy is assessed through the NSCAS framework

The ISF rule<sup>8</sup> requires AEMO to assess minimum fault level requirements in its annual NSCAS assessment. AEMO may only declare a system strength NSCAS gap if it occurs because AEMO has increased the minimum fault level requirements within a three-year window<sup>9</sup>. If AEMO has not increased the minimum fault level or a potential gap is identified outside the three-year window, then this is highlighted as a ‘system strength deficit’ rather than a system strength NSCAS gap.

A system strength deficit does not trigger any procurement or regulatory action. It is reported for visibility only, as the conditions for declaring an NSCAS gap have not been satisfied. While no new obligations arise for AEMO or the TNSPs in response to a system strength deficit<sup>10</sup>, the TNSP has ongoing obligations to plan for the system strength requirements set out in this report.

<sup>7</sup> At <https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system>.

<sup>8</sup> At <https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition>.

<sup>9</sup> NER Chapter 10, definition of ‘NSCAS gap’ and ‘NSCAS need’.

<sup>10</sup> AEMO recently submitted a rule change request to provide firmer oversight of TNSP planning, with forecast shortfalls for system strength and inertia able to be declared by AEMO which trigger obligations. See <https://www.aemc.gov.au/rule-changes/security-framework-enhancements> for further details.

## A2.2 New South Wales

- AEMO has confirmed an emerging thermal and voltage risk following Eraring retirement, which is only fully addressed by committed, anticipated projects and actionable projects. Transgrid is progressing the Hunter Transmission Project and Sydney Ring South to improve power transfer to Sydney. While AEMO expects these projects will resolve supply issues, AEMO will work closely with Transgrid to investigate impacts of actionable transmission projects on voltage and thermal risks once a preferred option is identified.
- An inertia deficit of 3,099 megawatt seconds (MWS) to 6,720 MWS from 2027-28 against the sub-network allocation has been identified, but solutions are in progress:
  - By 2029-30 the deficit is addressed by the synchronous condensers installed as part of the preferred option in Transgrid’s System Strength RIT-T.
  - Until then, synchronous condensers will not be fully operational, leaving interim deficits of 2,220–4,236 MWS for 2027-28 and 2028-29. The RIT-T’s preferred option also outlines additional measures, such as contracts with generators or similar arrangements, to address these interim deficits. These contracts were not modelled due to insufficient information
- Immediate system strength deficits ranging from 163 megavolt amperes (MVA) to 5,711 MVA at Armidale, Sydney West, Newcastle and Wellington have been confirmed. Solutions are in progress but may not be available in time to avoid the need for potentially significant operational intervention by AEMO:
  - Synchronous condensers to be installed under the preferred option in Transgrid’s System Strength RIT-T will partially address these deficits if delivered in time, leaving residual shortfalls of 111 MVA to 3,778 MVA.
  - These residual deficits could be partially managed through additional generator contracts or similar solutions, as described in the preferred RIT-T option, but not modelled due to insufficient information.
  - If security contracts are unavailable, operational intervention may be required by AEMO up to 30% of the time, at significant cost to consumers, to avoid potential consequences of greater severity. Furthermore, without these synchronous condensers the New South Wales power system could face periods where there may not be enough large synchronous units available for AEMO to direct online for system strength, creating a plausible risk of last resort operational actions such as de-energising critical power system assets or shedding customer load to maintain power system security.
- AEMO has not made any updates to the system strength node or the minimum three phase fault level requirements, and the efficient level of system strength has been updated using the latest available information from the Draft 2026 ISP at the time of writing.
- AEMO has not made any updates to the inertia requirements.

This section covers:

- inertia requirements, including the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level over a 10-year horizon,

- system strength requirements, comprising the identification of system strength nodes, minimum fault level requirements over a 10-year horizon, and the 10-year forecast of IBR, used to determine the efficient level of system strength, and
- NSCAS assessment details, including considerations for both inertia and system strength projections against the requirements.

### A2.2.1 Inertia requirements

AEMO has confirmed that the inertia requirements for New South Wales remain unchanged this year. **Table 2** provides a summary of the inertia requirements for New South Wales, including the satisfactory and secure inertia levels when planning for potential islanded operation, and the sub-network allocation of the system-wide inertia level. Transgrid is required to ensure sufficient inertia services are available to meet its sub-network allocation from 2 December 2027.

In addition to the system-wide inertia requirements, AEMO has determined minimum regional interconnected inertia levels for each region. While these levels are not regulatory obligations under NER 5.20B.2, they represent the practical amount of inertia that is required to be available within the region to withstand a contingency within that region, as detailed in Section A2.1.

For New South Wales, the minimum interconnected inertia level is 7,500 MWs. If regional inertia falls below this threshold, supporting inertia from neighbouring regions may be insufficient to maintain compliance with the Frequency Operating Standard (FOS) following a credible contingency, due to high network impedances between regions. The calculation and operational application of these minimum regional interconnected inertial levels is described in detail in Section A2.1.

**Table 2 New South Wales inertia requirements from 2 December 2025 to 1 December 2035**

Quantity	Value
Satisfactory inertia level	10,000 MWs
Secure inertia level	12,500 MWs
Inertia sub-network allocation	9,600 MWs
Minimum regional interconnected inertia level	7,500 MWs
Likelihood of islanding	Unlikely

#### A2.2.1.1 Likelihood of islanding

**Table 3** presents the criteria assessed when determining the likelihood of the New South Wales inertia sub-network islanding from the remainder of the system.

**Table 3 Assessment of the likelihood of New South Wales islanding**

Criterion	New South Wales
Inertia levels compared to secure inertia level	Inertia levels forecast to be below the secure inertia level from 2027-28.
Inertia sub-network allocation	9,600 MWs
Existing interconnections	Two 220 kilovolts (kV) alternating current (AC), three 330 kV AC, and one 132 kV AC connection to Victoria. One 330 kV AC double-circuit and one direct current (DC) link connection to Queensland. 330 kV AC single-circuit to South Australia

Criterion	New South Wales
Future interconnections and status	Project EnergyConnect (PEC) Stage 2: 330 kV AC double-circuit to South Australia replacing the existing single-circuit line. Victoria – New South Wales Interconnector West (VNI West): 500 kV AC double-circuit to Victoria. Queensland – New South Wales Interconnector (QNI) Connect: 330 kV AC double-circuit to Queensland.
History of islanding	N/A
Applicable control schemes	N/A
Likelihood of islanding after contingency event	Not likely

### A2.2.1.2 Co-optimisation with contracted fast frequency response (FFR) and 1-Second FCAS

The amount of FFR available in the NEM has increased rapidly in the last half a decade, due to significant battery connections. The 1-second FCAS market was introduced as a mechanism for procuring FFR to meet the FOS.

The role of the inertia requirements is to slow down the change in frequency which occurs after a generation or load contingency until FCAS responds to contain and restore frequency. Following the staged introduction of 1-Second FCAS from 2023, less inertia has been required because FCAS now responds faster.

The NEM is now reaching a point where additional FFR may no longer allow the inertia requirements to decrease. In every region, the limiting factor in meeting the FOS under current levels of FFR is no longer the nadir<sup>11</sup> but rather the rate of change of frequency (RoCoF) over the first 300-500 milliseconds (ms). FFR is very effective at limiting the frequency nadir, but inertia is the most appropriate tool for limiting RoCoF over the first 300-500 ms.

In previous inertia reports, FFR curves have been used as a tool to determine the trade-off between inertia and FFR. Continued work studying this phenomenon in PSS®E shows these curves are unlikely to extrapolate to the levels of FFR currently available in the NEM. AEMO intends to consider the impact of additional FFR on inertia requirements on a case-by-case basis.

BESS are still able to contribute significantly to meeting the inertia requirements by providing synthetic inertia which is similarly as effective as synchronous inertia in limiting RoCoF.

### A2.2.2 System strength requirements

AEMO has confirmed the system strength nodes, and their minimum fault level requirements continue to be maintained at the present values in the 2025 report. AEMO has also updated the IBR projections in New South Wales used to determine the efficient level of system strength, based on the latest available preliminary information from the Draft 2026 ISP.

#### A2.2.2.1 Summary of IBR projections for New South Wales

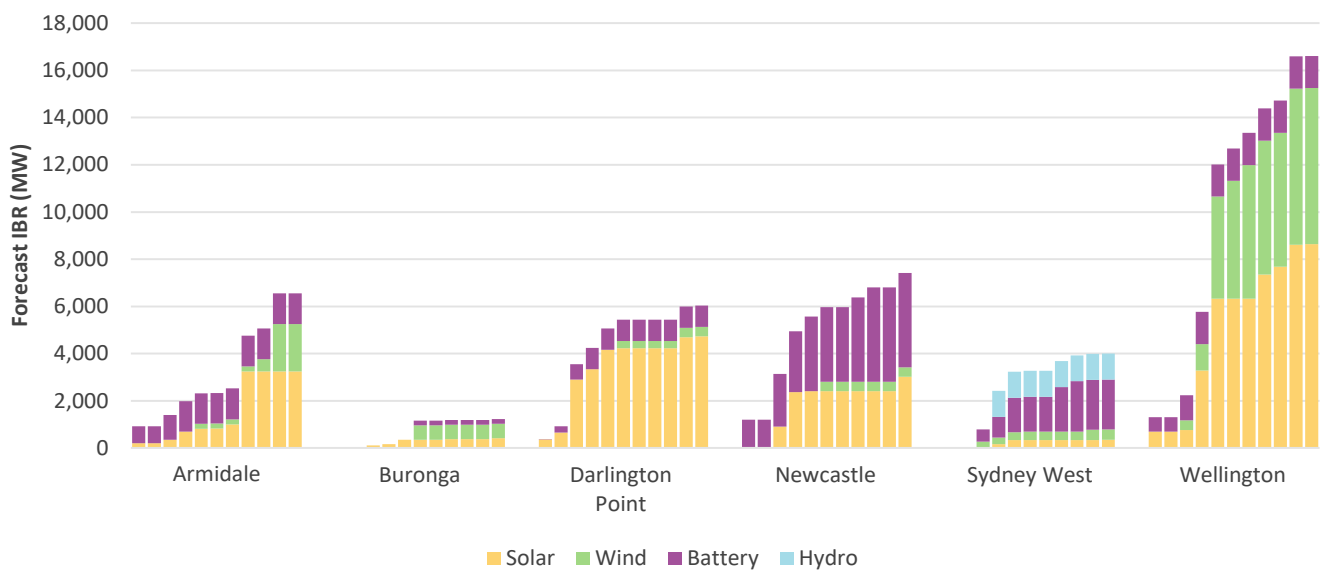
AEMO’s 10-year projection of the level and type of IBR and schedule 5.3a plant for New South Wales system strength nodes under NER 5.20C.1(c)(2)(ii) is summarised in **Figure 2**. Details for each node are provided in Section A2.2.2.2. As defined in NER S5.1.14(a), **Figure 2** defines the ‘efficient level’ IBR forecast component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028.

<sup>11</sup> In this context, the frequency nadir is the lowest point of frequency in a power system after a disturbance.

This IBR forecast is primarily based on the Draft 2026 ISP modelling, which AEMO has allocated to specific nodes based on local network knowledge and engineering judgement. The Draft 2026 ISP is published after this system strength report<sup>12</sup> and projections may slightly differ to the preliminary results which informed this IBR forecast.

AEMO expects that Transgrid, as the SSSP in New South Wales, may engage in joint planning with neighbouring SSSPs to identify any investment efficiencies when assessing the nature of solutions required to meet these requirements. AEMO supports SSSPs considering the latest available information and announcements to adjust this IBR forecast for use in their planning activities between publications of the system strength report, as outlined in Section A2.8.1.1. This will need to include any outcomes from the consultation process EnergyCo is undertaking on the approach for planning system strength for the New England REZ<sup>13</sup>.

**Figure 2** Forecasts of IBR and schedule 5.3a plant for 10 years from 2025-26, New South Wales



### A2.2.2.2 Nodal IBR projections for New South Wales

#### Armidale 330 kilovolts (kV)

**Table 4** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 4** Armidale node utility-scale IBR projections

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Armidale 330 kV	Solar	828	201	201	346	693	822	834	1,005	3,243	3,243	3,243	3,243
	Wind	445	0	0	0	210	210	210	210	517	2,010	2,010	2,010
	Battery	0	725	725	1,050	1,291	1,291	1,291	1,308	1,308	1,308	1,308	1,308
	<b>Total IBR</b>	<b>1,273</b>	<b>926</b>	<b>926</b>	<b>1,396</b>	<b>1,984</b>	<b>2,323</b>	<b>2,335</b>	<b>2,523</b>	<b>4,761</b>	<b>5,068</b>	<b>6,561</b>	<b>6,561</b>

<sup>12</sup> The Draft 2026 ISP will be published on 10 December 2025 as per the ISP Timetable, at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>.

<sup>13</sup> See <https://www.energyco.nsw.gov.au/sites/default/files/2025-08/new-england-rez-generation-and-storage-consultation-paper.pdf>.

### Buronga 220 kV

Table 5 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 5 Buronga node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Buronga 220 kV	Solar	594	0	0	117	160	354	354	354	372	372	372	416
	Wind	198	0	0	0	0	0	613	613	613	613	616	616
	Battery	207	0	0	0	0	0	200	200	200	200	200	200
	Total IBR	999	0	0	117	160	354	1,167	1,167	1,185	1,185	1,188	1,232

### Darlington Point 330 kV

Table 6 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 6 Darlington Point node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Darlington Point 330 kV	Solar	1,984	360	660	2,896	3,334	4,164	4,234	4,234	4,234	4,234	4,688	4,730
	Wind	0	0	0	0	0	0	300	300	300	300	400	400
	Battery	170	10	260	655	905	905	905	905	905	905	905	905
	Total IBR	2,154	370	920	3,551	4,239	5,069	5,439	5,439	5,439	5,439	5,993	6,035

### Newcastle 330 kV

Table 7 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 7 Newcastle node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Newcastle 330 kV	Solar	0	0	0	914	2,373	2,407	2,407	2,407	2,407	2,407	2,407	3,018
	Wind	0	0	0	0	0	0	400	400	400	400	400	400
	Battery	1,095	1,200	1,200	2,225	2,575	3,167	3,167	3,167	3,579	4,006	4,006	4,006
	Total IBR	1,095	1,200	1,200	3,139	4,948	5,574	5,974	5,974	6,386	6,813	6,813	7,424

### Sydney West 330 kV

Table 8 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 8 Sydney West node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Sydney West 330 kV	Solar	42	0	0	0	171	332	332	332	332	332	332	350
	Wind	1,777	0	0	270	270	333	370	370	370	370	441	441
	Battery	254	0	0	525	878	1,470	1,470	1,470	1,882	2,126	2,116	2,116
	Hydro	0	0	0	0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
	Total IBR	2,073	0	0	795	2,419	3,235	3,272	3,272	3,684	3,928	3,989	4,007

Wellington 330 kV

Table 9 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 9 Wellington node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Wellington 330 kV	Solar	2,292	702	702	762	3,285	6,322	6,322	6,322	7,356	7,682	8,619	8,643
	Wind	399	0	0	414	1,116	4,331	4,996	5,671	5,671	5,671	6,606	6,606
	Battery	0	607	607	1,067	1,367	1,367	1,367	1,367	1,367	1,367	1,367	1,367
	Total IBR	2,691	1,309	1,309	2,243	5,768	12,020	12,685	13,360	14,394	14,720	16,592	16,616

A2.2.2.3 Minimum fault level requirements for New South Wales

The New South Wales minimum fault level requirements under NER 5.20C.1(c)(2)(i) applicable for planning purposes over the next ten years are summarised in Table 10 below. The minimum fault level requirements under NER 5.20C.1(c)(1) applicable for operational purposes over the next one year are given in Section A2.9. As defined in NER S5.1.14(a), the values in the table define the minimum fault level component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028. No changes have been made to the minimum fault levels for New South Wales in the 2025 system strength report.

**Table 10 Minimum fault level requirements for New South Wales**

Node	Pre-contingent (secure) minimum fault level (MVA)	Post-contingent minimum fault level (MVA)	Contingency applicable for post-contingent level	Last changed
Armidale 330 kV	3,300	2,800	Tamworth – Armidale 330 kV line	2020 System Strength Report
Buronga 220 kV	1,755	905	Wagga – Darlington Point 330 kV line	2024 System Strength Report
Darlington Point 330 kV	1,500	600	Wagga – Darlington Point 330 kV line	2020 System Strength Report
Newcastle 330 kV	8,150	7,100	Liddell – Newcastle 330 kV line	2020 System Strength Report
Sydney West 330 kV	8,450	8,050	Sydney West – Sydney North 330 kV line	2020 System Strength Report
Wellington 330 kV	2,900	1,800	Wollar – Wellington 330 kV line	2020 System Strength Report

#### A2.2.2.4 System strength nodes

AEMO has not declared any new system strength nodes nor set retirement dates for existing nodes in the 2025 system strength report. Possible future nodes in New South Wales are described in **Table 11**. These nodes may be declared in a future system strength report, subject to the changing needs of the power system.

**Table 11 Possible future nodes in New South Wales and closures of existing nodes**

System strength node	Voltage and busbar	Effective date range	Purpose of new node
Dinawan	Dinawan 330 kV	TBC	Facilitate potential future IBR

#### A2.2.2.5 Critical planned outages

SSSPs are expected to consider critical planned outages in their proposed system strength solutions on a case-by-case basis<sup>14</sup>. AEMO has declared several critical planned outages as impactful for maintaining system strength in New South Wales, and these are presented in **Table 12**. Four additional entries have been added in this report, specifically line 81 at Newcastle, and line 72, 7M, and line 79 at Wellington.

**Table 12 Critical planned outages in New South Wales for each system strength node**

Affected node	Network outage	Reason for consideration as a critical outage
Armidale	83 Liddell to Muswellbrook 330 kV line	Loss of another 330 kV line during this outage leaves Armidale connected to Queensland network. Post-contingency fault level at Armidale 330 kV bus depends on southern Queensland generation.
	84 Liddell to Tamworth 330 kV line	
	88 Muswellbrook to Tamworth 330 kV line	
	85 Tamworth to Uralla 330 kV line	
	86 Tamworth to Armidale 330 kV line	
	8U Uralla to Armidale 330 kV line	
Darlington Point	O51 – Lower Tumut to Wagga Wagga 330 kV line	Can lead to a reduction in significant IBR that may have power system consequences. X5, 63 and 996 lines to be opened, Yass to Wagga 132 lines to be opened as necessary.
	62- Jindera to Wagga Wagga 330 kV line	
	63 – Wagga Wagga to Darlington Point 330 kV line	
	X5 – Darlington Point to Balranald 220 kV line	
	O60 – Jindera to Dederang 330 kV line	
Newcastle	81L Liddell to Bayswater 330 kV line <sup>A</sup>	Loss of another 330 kV line will reduce the fault level contribution from Bayswater and Mt Piper significantly. These outages have been included due to the announced closure of Eraring Power Station.
	81N Bayswater to Newcastle 330kV line <sup>A</sup>	
	82 Liddell to Tomago 330 kV Line	
Wellington	72 Wellington to Mt Piper	Loss of another 330 kV line will reduce fault levels contributions from the 500 kV network significantly which can require constraining a large number of IBR at the Wellington node.
	79 Wellington to Stubbo	
	7M Stubbo to Wollar West	

A. The 81 Liddell to Newcastle line will be split into 81L and 81N sections after Central West Orana augmentations.

<sup>14</sup> AEMO, *System Strength Requirements Methodology*, Section 4.5, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/system-strength-requirements-methodology-v21.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/system-strength-requirements-methodology-v21.pdf).

### A2.2.3 NSCAS assessment

AEMO assessed NSCAS needs in New South Wales over a five-year outlook period, under a range of demand, generation, and network project assumptions. This section summarises the results of these assessments relating to:

- voltage control and thermal loading (Section A2.2.3.1),
- rapid voltage change (Section A2.2.3.2),
- reactive margin (Section A2.2.3.3),
- system strength, over a three-year period (Section A2.2.3.4),
- inertia, over a three-year period (Section A2.2.3.5), and
- market benefit ancillary services (MBAS, Section A2.2.3.6).

**Table 13** provides an overview of the core scenarios studied for New South Wales. Section A2.8 provides more detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2025 NSCAS assessment.

**Table 13 New South Wales NSCAS scenarios and outcomes**

Case	Scenario assumptions	Year of assessment	NSCAS gap
Low demand (day)	Committed Projects Only	2025-26	Emerging risk – managed operationally
	Committed Projects Only	2030-31	Emerging risk
Low demand (night)	Committed Projects Only	2025-26	Emerging risk – managed operationally
	Committed Projects Only	2030-31	Emerging risk
High demand	Committed Projects Only	2025-26	Emerging risk – managed operationally
	Committed Projects Only	2030-31	Emerging thermal and voltage risk. AEMO expects actionable projects identified in the 2024 ISP will be required to address supply related issues.
	Committed and anticipated projects <sup>A</sup>	2030-31	Emerging thermal and voltage risk. AEMO expects actionable projects identified in the 2024 ISP will be required to address supply related issues.
System strength	Modified ESOO scenario <sup>B</sup> ,	2025-26 to 2029-30	Deficits identified at Armidale, Sydney West, Newcastle and Wellington, but no gap declared <sup>C</sup>
System strength	Modified ESOO scenario <sup>B</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	Deficits identified at Armidale, Sydney West, Newcastle and Wellington, but no gap declared <sup>C</sup>
Inertia	Modified ESOO scenario <sup>B</sup> ,	2025-26 to 2029-30	Deficits identified against the inertia sub network allocation, but no gap declared <sup>C</sup>
Inertia	Modified ESOO scenario <sup>B</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	Deficits identified against the inertia sub network allocation, but no gap declared <sup>C</sup>

A. This scenario includes anticipated, generation and storage projects, and installed plant of the preferred option in the System Strength RIT-T for New South Wales.

B. Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station closure notification (see.

<https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>).

C. This deficit will be partially addressed by the solutions modelled parts of the System Strength RIT-T, but some deficit remains which could be addressed via contracts with generators or similar. See Section A2.2.2 for details

#### A2.2.3.1 Voltage control and thermal loading

AEMO has assessed expected voltage control and thermal loading issues in New South Wales over a five-year outlook period, under both low and high demand scenarios. This included testing several different assumptions relating to

committed changes to both generation and transmission projects. Further inputs and assumptions details can be found in Section A2.8.

No gaps were identified under system normal operating conditions or following single credible contingency events. However, several emerging thermal loading and voltage control challenges have been identified under maximum and minimum demand which are only fully addressed by committed, anticipated projects and actionable projects.

### Managing voltage control between Coffs Harbour and Taree

AEMO has investigated simulations under light loading conditions of 132 kV lines between Coffs Harbour and Taree, and has identified high voltage scenarios under system normal conditions and the trip of the Coffs Harbour 330/132 kV transformer. While the voltages are high, they were not seen to exceed limits and operation measures exist to manage voltages in the area.

### Emerging risk for thermal loading and voltage control whilst supplying demand growth near Sydney

AEMO identified in the 2024 NSCAS Report the growing risk of managing supply to forecast demand growth near Sydney. As coal units retire, power flow patterns and voltage profiles of the network will likely change which creates new risks in managing congestion and system security in periods of peak demand. Similar studies have been conducted this year based on revised transmission, generation, storage and demand projections. Demand projections and modelling have incorporated localised demand at high growth supply points in Holroyd 330 kV, Vineyard 330 kV, Kemps Creek 330 kV, Macarthur 132 kV and 66 kV, Sydney North 330 kV and Sydney West 330 kV.

AEMO's studies indicate management of thermal loading and voltage control risks remain a challenge, even with committed and anticipated transmission, generation and storage projects considered in the New South Wales development pipeline. The 2025 NSCAS voltage and thermal assessment considered a sensitivity scenario including development of committed transmission projects (HumeLink and Central-West Orana REZ Network Infrastructure Project) plus Transgrid's proposed system strength RIT-T<sup>15</sup> and committed and anticipated generation and storage projects. These projects provide additional sources of capacity and voltage support during peak demand conditions. However, supporting high transfer of power to major supply points in the Sydney region remains a challenge. AEMO will continue to work with Transgrid on assessing how network projects may address this issue.

#### A2.2.3.2 Rapid voltage change

AEMO assessed the expected voltage change impacts of switching reactive plant in New South Wales. **Table 14** summarises the results of this analysis indicating maximum voltage deviations for a given case, the appropriate International Electrotechnical Commission (IEC) Standard<sup>16</sup>, and whether that standard is met. The results demonstrate that the standard is met for all conditions assessed.

<sup>15</sup> Transgrid, July 2025, see <https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf>.

<sup>16</sup> Requirements for voltage fluctuation are defined by NER S5.1a.5 and TR IEC 61000.3.7 Table 6, Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed four within a 24-hour period, with each change allowing a permissible variation of 3-5% for network elements operated at greater than 230 kV and 5-6% for network elements operated at voltages between 35 kV and 230 kV.

Table 14 Rapid voltage change results for reactive plant switching in New South Wales

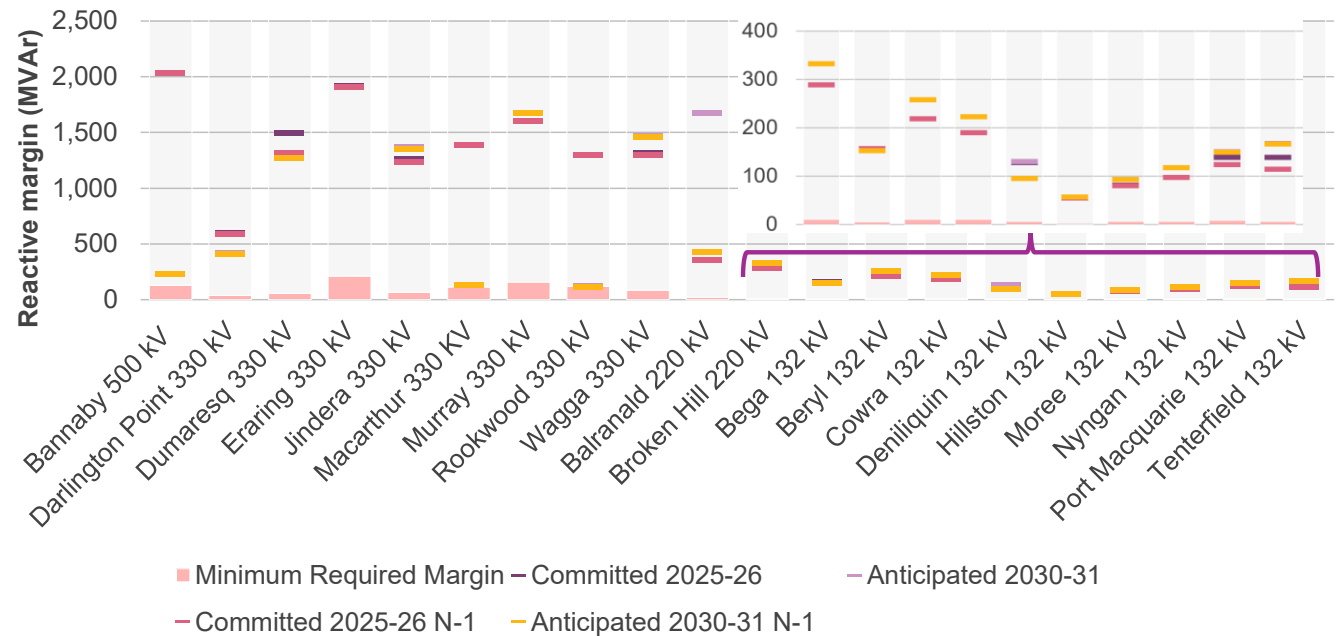
Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Minimum demand day	Committed Projects Only	2025-26	2.74%	Buronga 330 kV	50 megavolt amperes reactive (MVAR) reactor at Buronga 330 kV Bus	3-5%	Yes
	Committed Projects Only	2030-31	1.37%	Darlington Pt 220 kV	33 MVAR reactor at Darlington Pt 220 kV Bus		Yes
Minimum demand night	Committed Projects Only	2025-26	3.18%	Buronga 330 kV	50 MVAR reactor at Buronga 330 kV Bus		Yes
	Committed Projects Only	2030-31	1.82%	Balranald 220 kV	20 MVAR capacitor at Balranald 220 kV Bus		Yes
Maximum demand	Committed Projects Only	2025-26	3.12%	Yass 132 kV	80 MVAR capacitor at Yass 132 kV Bus		Yes
	Committed and anticipated projects	2030-31	3.16%	Kangaroo Valley 330 kV	200 MVAR capacitor at Kemps Creek 330 kV Bus	Yes	

### A2.2.3.3 Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in New South Wales are expected to remain above the system standard<sup>17</sup> of 1% of the local maximum fault level over the five-year outlook period.

Figure 3 summarises the results, and indicates that all reactive margins are projected to meet the standard.

Figure 3 Minimum reactive margin (megavolt amperes reactive [MVAR]) observed for critical buses in New South Wales



<sup>17</sup> Required reactive margin is defined by NER S5.1.8 as “not less than 1% of the maximum fault level (in MVA) at the connection point”. For the purposes of this assessment, the required reactive margin was calculated based on the 2025-26 maximum fault level.

The studies included separate ‘system typical’ outages of Lismore Static VAR Compensator (SVC), the 132 kV line between Finley and Uranquinty, and the 132 kV line between Jindera and Albury out of service in the N-1 cases.

AEMO’s studies indicate reactive margins near Sydney and in central New South Wales worsen with de-commitment of large coal units and increasing load near Sydney. AEMO will continue to monitor this issue as new reactive power sources become committed and demand grows.

#### A2.2.3.4 System strength

AEMO modelled projected fault level requirement under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>18</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in section A2.8.2.as described in Section A2.8.2.

The expected three phase fault current at each system strength node in New South Wales was compared against the latest minimum fault current requirements published in Section A2.2.2. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year<sup>19</sup>.

The results of this assessment are summarised in **Table 16**, and confirm that there are significant system strength deficits projected across New South Wales from 2025-26. The deficits largely occur during periods when multiple coal units take maintenance at once during spring as per current MT PASA schedules<sup>20</sup>, and are worsened by coal retirement starting with the announced closure of Eraring in August 2027. Additional drivers include two-shifting of coal in New South Wales which is already being observed. The deficits identified at Sydney West and Newcastle in 2027-28 are 2,300-3,100 MVA larger than in the 2024 *System Strength Report* due to both consideration of MT PASA maintenance patterns and two-shifting, which were not considered<sup>21</sup> in the 2024 *System Strength Report*.

AEMO also modelled fault level projections under an outlook which included some parts of the preferred options from each TNSP’s system strength RIT-T (RIT-T outlook) where modelling information was available or a reasonable assumption could be made. The remainder of the preferred option was not modelled due to uncertainty with contracting or confidentiality. Through joint planning with TNSPs, AEMO has used the latest available modelling information including the most up-to-date location, timing, inertia, and fault level contribution for synchronous condensers based on current procurement status, and services from non-network synchronous condensers and synchronous generation where a proponent has been identified. The parts of Transgrid’s system strength RIT-T preferred solution modelled in the RIT-T outlook for fault level projections are detailed in **Table 15** below.

<sup>18</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

<sup>19</sup> 99.87% is equivalent to three standard deviations above the mean. See [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc_lang=en).

<sup>20</sup> The combination of spring maintenance and two-shifting recently required directions to maintain system strength in New South Wales in August 2025 (Market Notice 128743) and October 2025 (Market Notices 129417, 130076, 130095, 130177, 130184, 130249, 130262, and 130280).

<sup>21</sup> Planned generator maintenance in the 2024 *System Strength Report* was determined by optimising capacity reserves across an outlook period as per the *ISP Methodology*, at [https://www.aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology\\_june-2023.pdf](https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf).

**Table 15 Parts of Transgrid’s System Strength RIT-T preferred option modelled in the RIT-T outlook for fault level projections**

Part of RIT-T preferred solution <sup>A</sup>	Included in the RIT-T outlook for fault level projections?
<b>Ten network synchronous condensers</b>	Included with latest modelling information based on the outcome of a tender for synchronous condensers <sup>B</sup> .
<b>Non-network contracts with synchronous units</b>	Only one synchronous power station was included based on available information leading up to publication of this report. More contracts are expected in the final portfolio of non-network contracts upon completion of tendering.
<b>GFM BESS</b>	Not included in fault level projections due to current lack of evidence that GFM BESS can provide protection quality fault current.

A. Transgrid, *Meeting system strength requirements in New South Wales Project Assessment Conclusions Report, 2025*, at <https://www.transgrid.com.au/media/kfhd21bg/250812-transgrid-system-strength-pacr.pdf>.

B. See <https://www.transgrid.com.au/media-publications/news-articles/nsw-secures-critical-grid-stabilising-machines-to-support-renewables-rollout>.

The modelled parts of the RIT-T solutions reduce the system strength deficit, but across the five-year horizon large deficits remain at Newcastle and Sydney West nodes, with smaller deficits remaining at Armidale and Wellington. Further analysis indicates that there is unlikely to be a system strength deficit in New South Wales beyond the modelled horizon in 2030-31 in the RIT-T outlook, due to the delivery of additional synchronous condensers by the end of 2029-30. Interim deficits will remain prior to 2030-31, which could be managed via contracts with generators or similar.

**Table 16 New South Wales fault level requirements and identified deficits against the requirements**

System strength node	Fault level requirement (MVA)	Identified deficit in the Modified ESOO scenario (MVA)					Identified deficit in the Modified ESOO scenario with modelled parts of the RIT-T solutions (MVA)				
		2025-26	2026-27	2027-28	2028-29	2029-30	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Armidale 330 kV</b>	3,300	0	0	362	663	343	0	0	241	0	0
<b>Darlington Point 330 kV</b>	1,500	0	0	0	0	0	0	0	0	0	0
<b>Newcastle 330 kV</b>	8,150	163	478	4,150	5,577	4,710	0	132	3,601	3,021	2,129
<b>Sydney West 330 kV</b>	8,450	1,058	1,142	4,464	5,711	4,721	445	531	3,778	3,077	1,985
<b>Wellington 330 kV</b>	2,900	0	193	610	1,093	563	0	111	463	351	0
<b>Buronga 220 kV</b>	1,755	0	0	0	0	0	0	0	0	0	0

Section A2.2.2 provides additional detail on the calculation of fault level requirements. Detailed projected fault levels per system strength node are shown below, with and without modelled parts of the RIT-T solutions.

The decommitment of Eraring before synchronous condensers are operational would result in the activation of Transgrid system security contracts (where available). Synchronous generator contracts are dispatched at all times in the modelled parts of the RIT-T solutions duration curves to ensure their impact is captured at all times of low system strength. It is expected that synchronous generator contracts will be dispatched operationally only as needed at times of low system strength.

If security contracts are unavailable, operational intervention may be required by AEMO up to 30% of the time, at significant cost to consumers, to avoid potential consequences of greater severity. Furthermore, without these synchronous condensers the New South Wales power system could face periods where there may not be enough large synchronous units



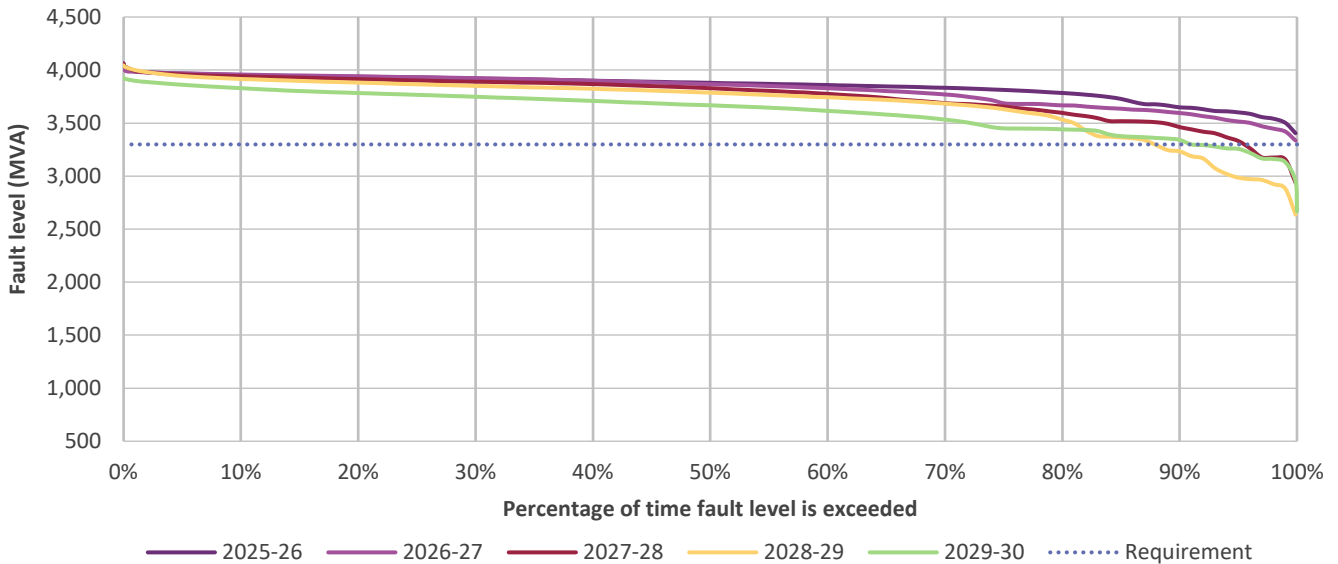
available for AEMO to direct online for system strength, creating a plausible risk of last resort operational actions such as de-energising critical power system assets or shedding customer load to maintain power system security.

### Armidale 330 kV

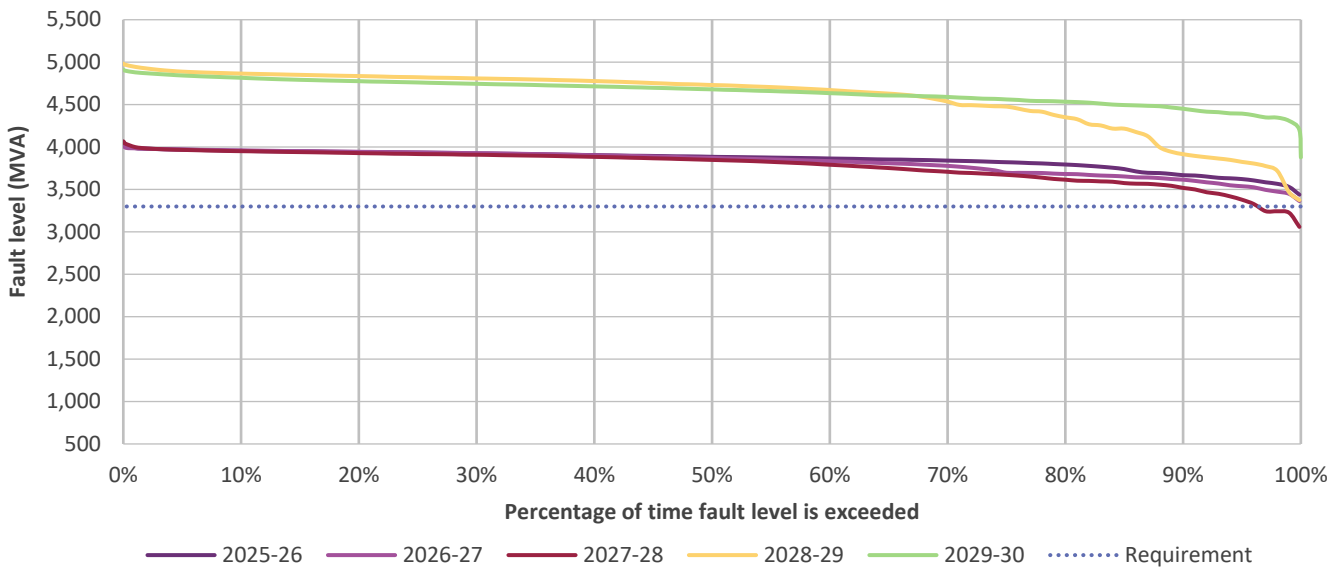
**Figure 4** shows the projected three phase fault level at the Armidale 330 kV node without the modelled parts of the RIT-T solution. The Armidale node sees a deficit in 2027-28, 2028-29 and 2029-30. **Figure 5** shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the deficit in 2028-29 and 2029-30 and reduces the deficit in 2027-28.

**Table 17** shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The modelled parts of the RIT-T preferred option are expected to address all deficits at Armidale except in 2027-28. Transgrid is currently tendering for additional synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficit.

**Figure 4 Armidale node fault level duration curves and minimum requirement**



**Figure 5 Armidale node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 17 Armidale node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Armidale 330 kV	Minimum fault level requirement (MVA)	3,300	3,300	3,300	3,300	3,300
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	3,403	3,336	2,938	2,637	2,957
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	3,437	3,364	3,059	3,376	4,203
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	362	663	343
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	241	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

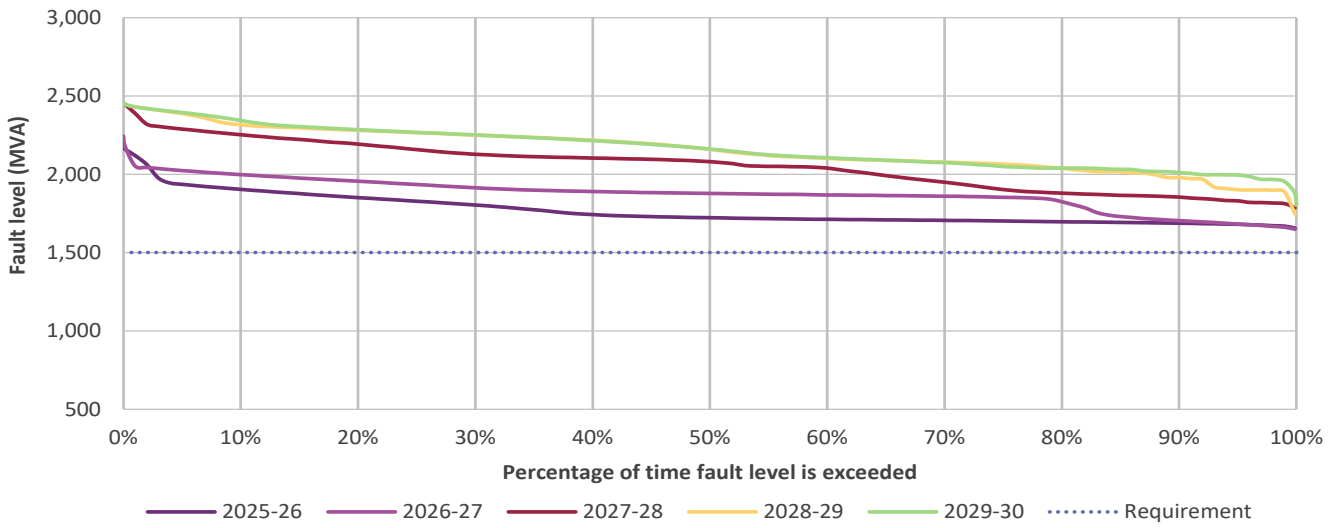
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Darlington Point 330 kV

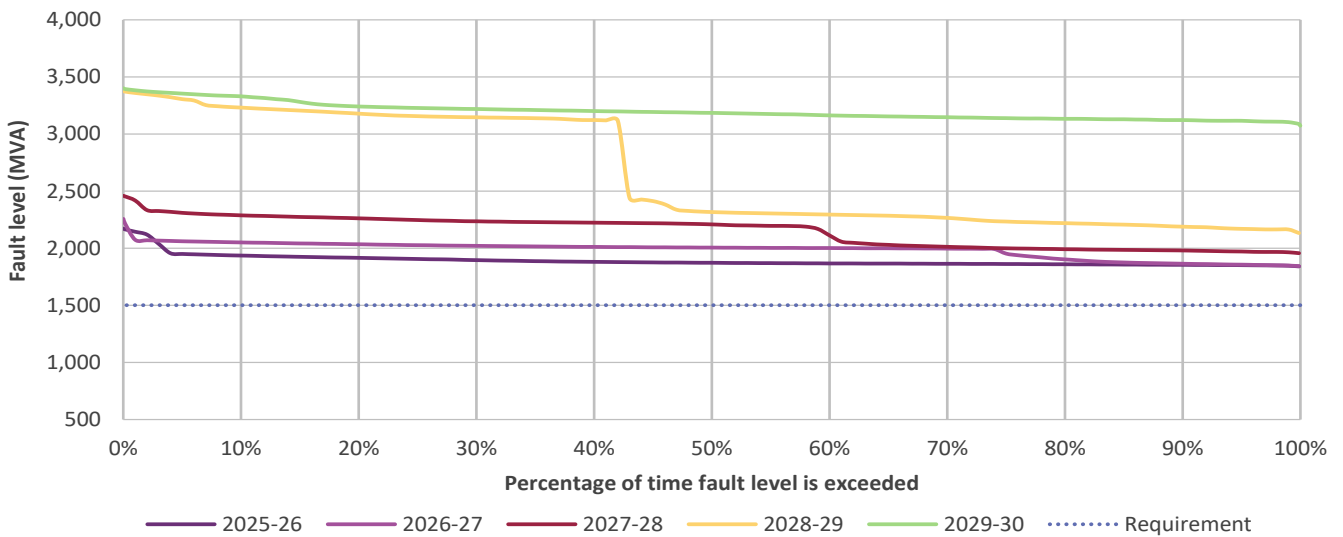
Figure 6 shows the projected three phase fault level at the Darlington Point 330 kV node without the modelled parts of the RIT-T solution. Darlington Point does not show any deficits in the modelling horizon. Figure 7 shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, showing a large increase in fault level for 2028-29 and 2029-30.

Table 18 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The large increase in fault levels from 2028-29 is driven by a synchronous condenser installed at Darlington Point in the New South Wales RIT-T preferred option. This is primarily to manage deficits which may occur during a critical planned outage from Table 12. Critical planned outages are not assessed in these fault level projections. As such, these projections may be considered as an upper bound on the actual fault level that will be available.

**Figure 6** Darlington Point node fault level duration curves and minimum requirement



**Figure 7** Darlington Point node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution



**Table 18** Darlington Point node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Darlington Point 330 kV	Minimum fault level requirement (MVA)	1,500	1,500	1,500	1,500	1,500
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	1,657	1,649	1,787	1,747	1,878
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	1,841	1,844	1,957	2,134	3,090
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.



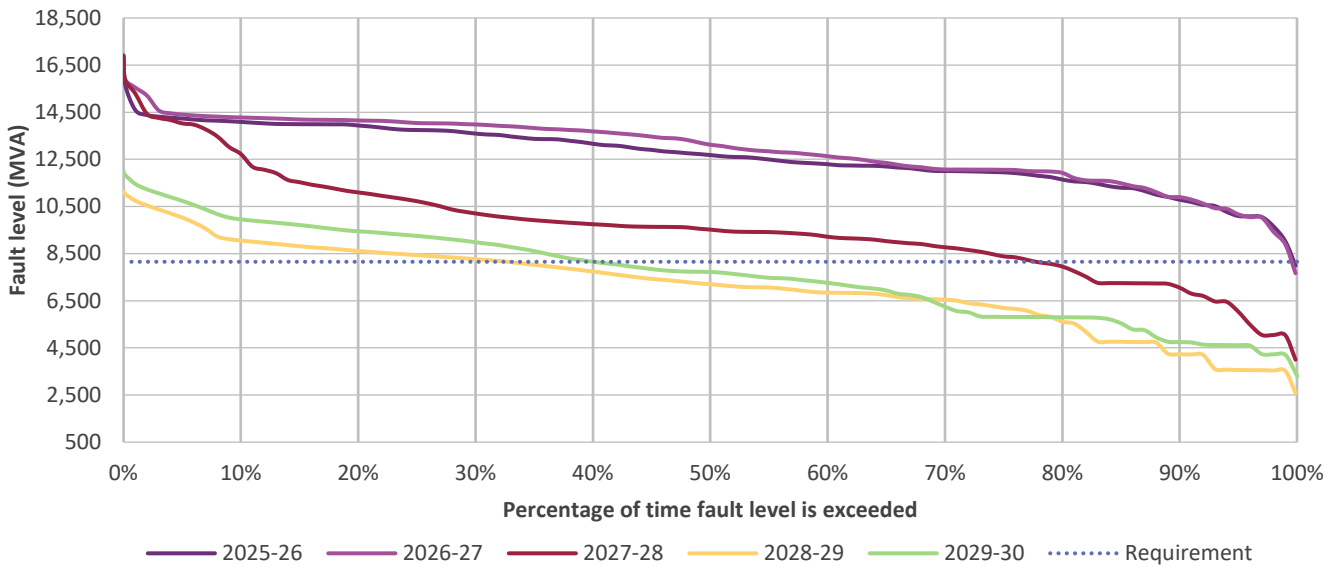
### Newcastle 330 kV

**Figure 8** shows the projected three phase fault level at the Newcastle 330 kV node without the modelled parts of the RIT-T solution. The Newcastle node sees deficits at the 99.87<sup>th</sup> percentile in all forecast years, most significantly beyond 2026-27.

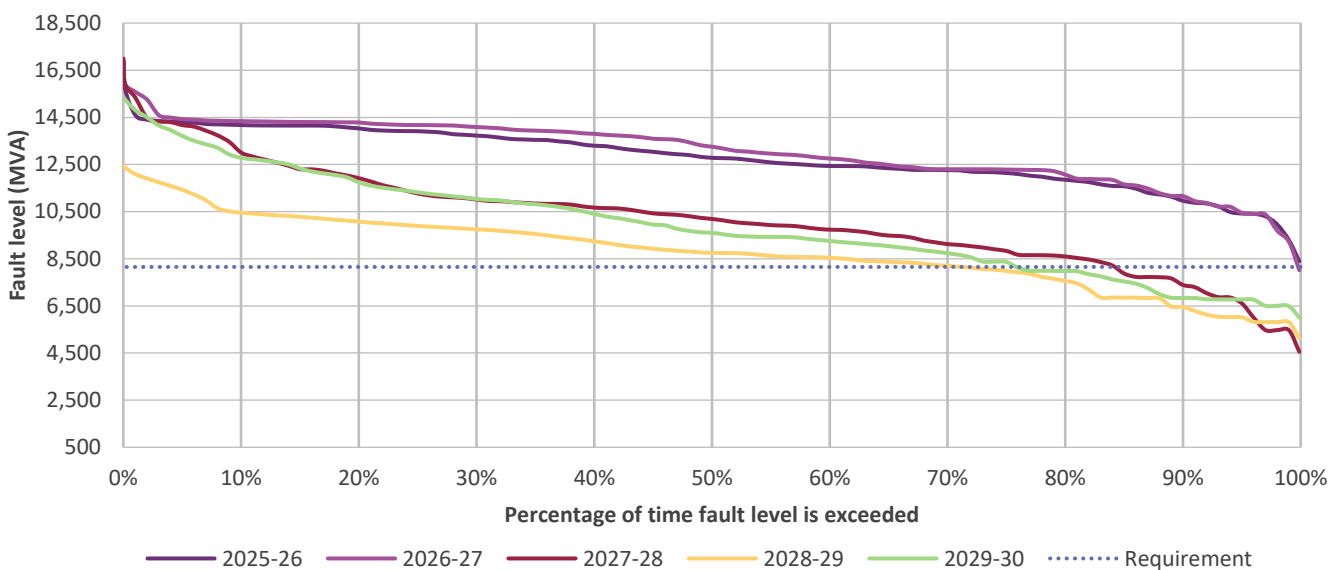
**Figure 9** shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the deficit in 2025-26 and significantly reduces the deficit in the years beyond.

**Table 19** shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The modelled parts of the RIT-T solutions are crucial for addressing the large deficit at Newcastle from 2027-28 due to retirement of Eraring and decommitment of other New South Wales coal units. Transgrid is currently tendering for additional synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficit.

**Figure 8 Newcastle node fault level duration curves and minimum requirement**



**Figure 9 Newcastle node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 19 Newcastle node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Newcastle 330 kV	Minimum fault level requirement (MVA)	8,150	8,150	8,150	8,150	8,150
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	7,987	7,672	4,000	2,573	3,440
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	8,398	8,018	4,549	5,129	6,021
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	163	478	4,150	5,577	4,710
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	132	3,601	3,021	2,129
	NSCAS gap (Yes/No)*	No	No	No	No	No

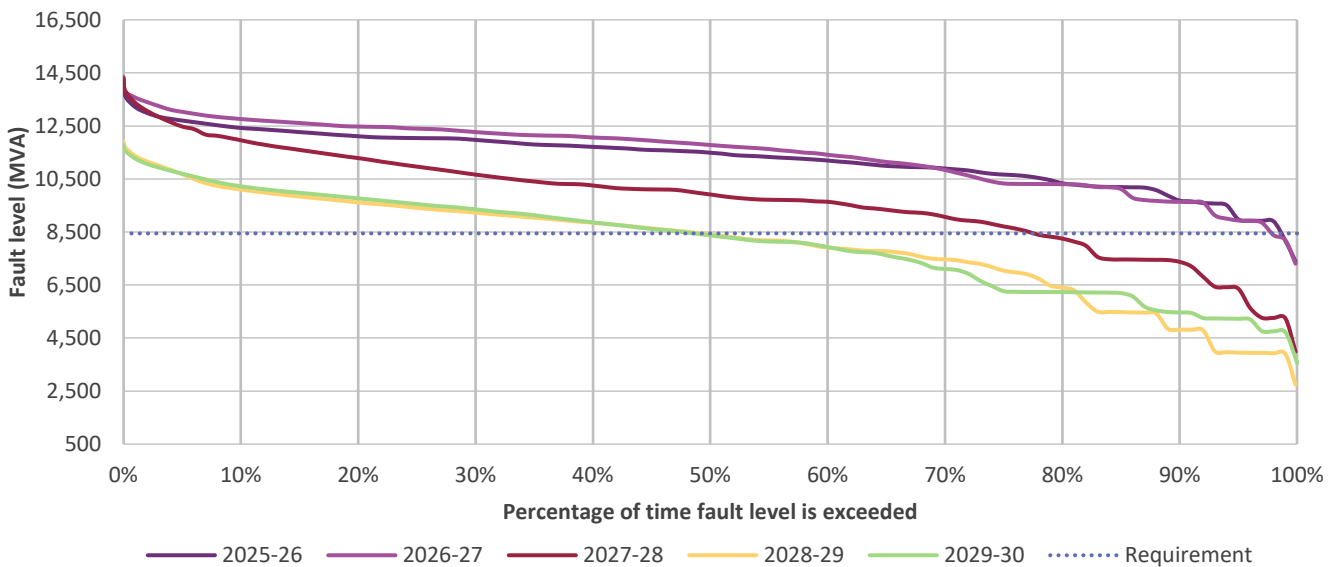
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Sydney West 330 kV

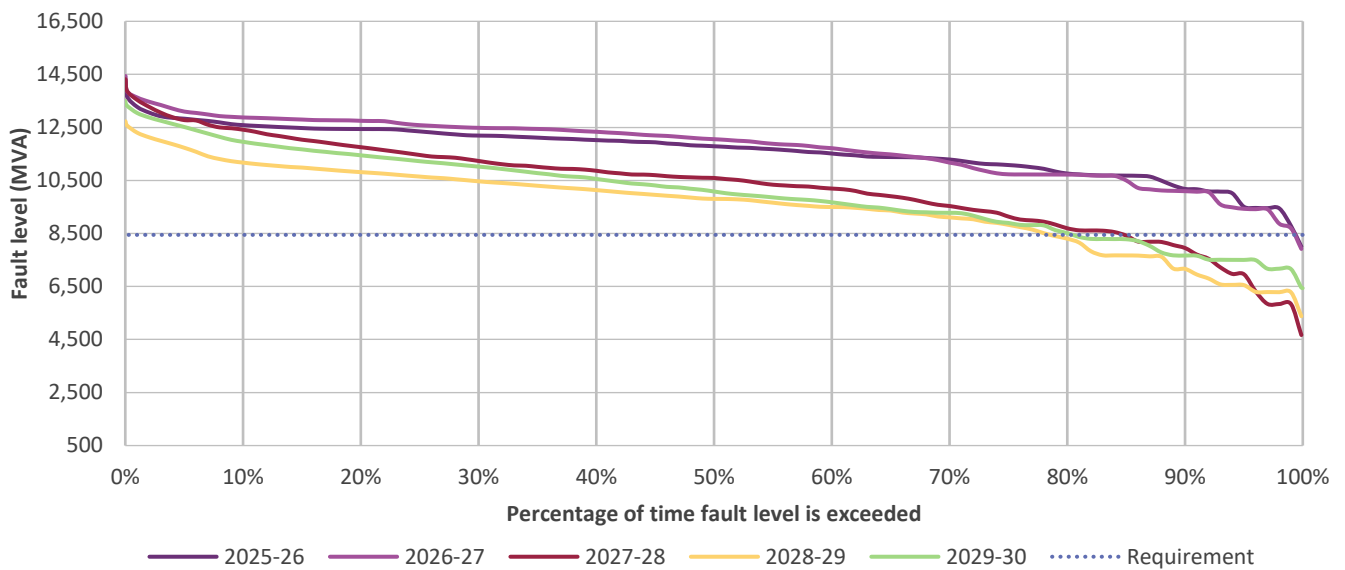
Figure 10 shows the projected three phase fault level at the Sydney West 330 kV node without the modelled parts of the RIT-T solution. Sydney West sees deficits at the 99.87<sup>th</sup> percentile in all forecast years. Figure 11 shows the projected fault levels after implementing the modelled parts of the RIT-T solutions – while a deficit at the 99.87<sup>th</sup> percentile remains, it is significantly reduced.

Table 20 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The modelled parts of the RIT-T solutions are crucial for addressing the large deficit at Sydney West from 2027-28 due to retirement of Eraring and decommitment of other New South Wales coal units. Transgrid is currently tendering for additional synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficit.

**Figure 10 Sydney West node fault level duration curves and minimum requirement**



**Figure 11 Sydney West node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 20 Sydney West node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Sydney West 330 kV	Minimum fault level requirement (MVA)	8,450	8,450	8,450	8,450	8,450
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	7,392	7,308	3,986	2,739	3,729
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	8,005	7,919	4,672	5,373	6,465
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	1,058	1,142	4,464	5,711	4,721
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	445	531	3,778	3,077	1,985
	NSCAS gap (Yes/No)*	No	No	No	No	No

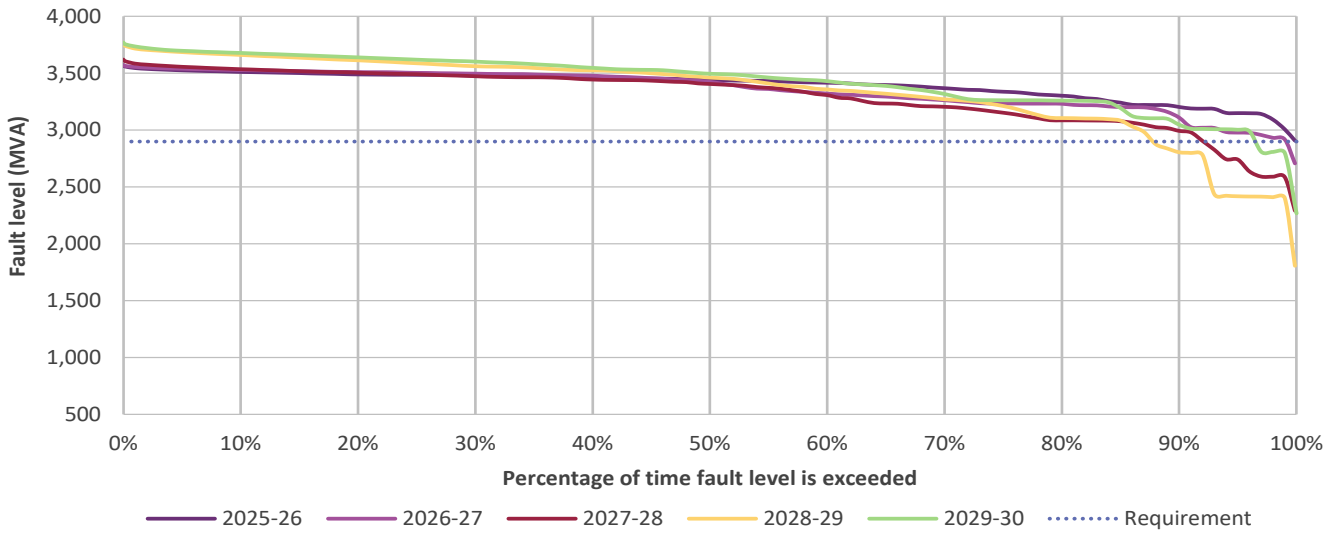
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Wellington 330 kV

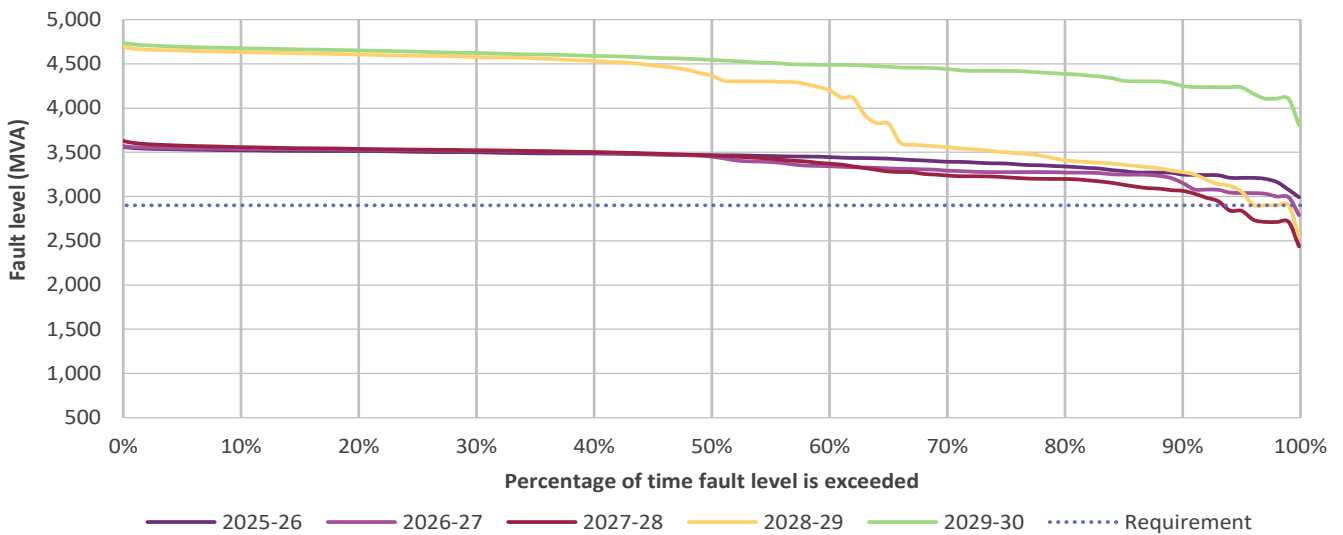
**Figure 12** shows the projected three phase fault level at the Wellington 330 kV node without the modelled parts of the RIT-T solution. This node sees deficits at the 99.87<sup>th</sup> percentile in 2026-27 and beyond. **Figure 13** shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the deficit in 2029-30 and reduces the deficit in 2026-27, 2027-28 and 2028-29.

**Table 21** shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The modelled parts of the RIT-T solutions address the deficits at Wellington by 2029-30 with smaller remaining deficits in the interim years from 2026-27 to 2028-29. Transgrid is currently tendering for additional synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficits.

**Figure 12 Wellington node fault level duration curves and minimum requirement**



**Figure 13 Wellington node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 21 Wellington node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Wellington 330 kV	Minimum fault level requirement (MVA)	2,900	2,900	2,900	2,900	2,900
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	2,906	2,707	2,290	1,807	2,337
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	2,991	2,789	2,437	2,549	3,816
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	193	610	1,093	563
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	111	463	351	0
	NSCAS gap (Yes/No)*		No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

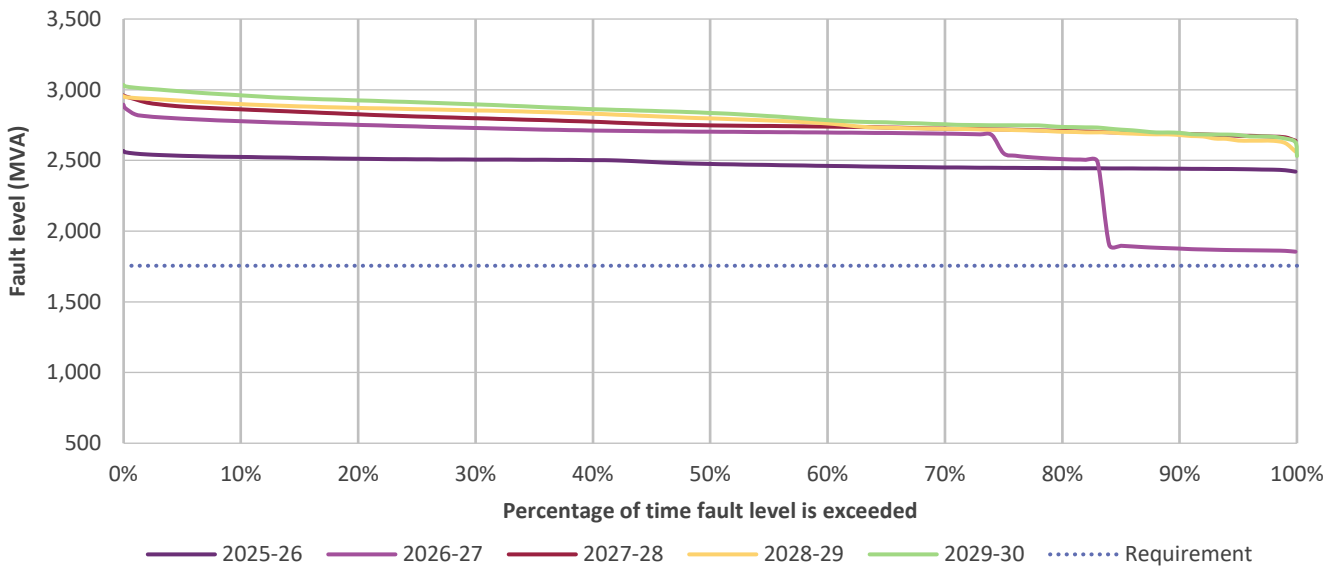


### Buronga 220 kV

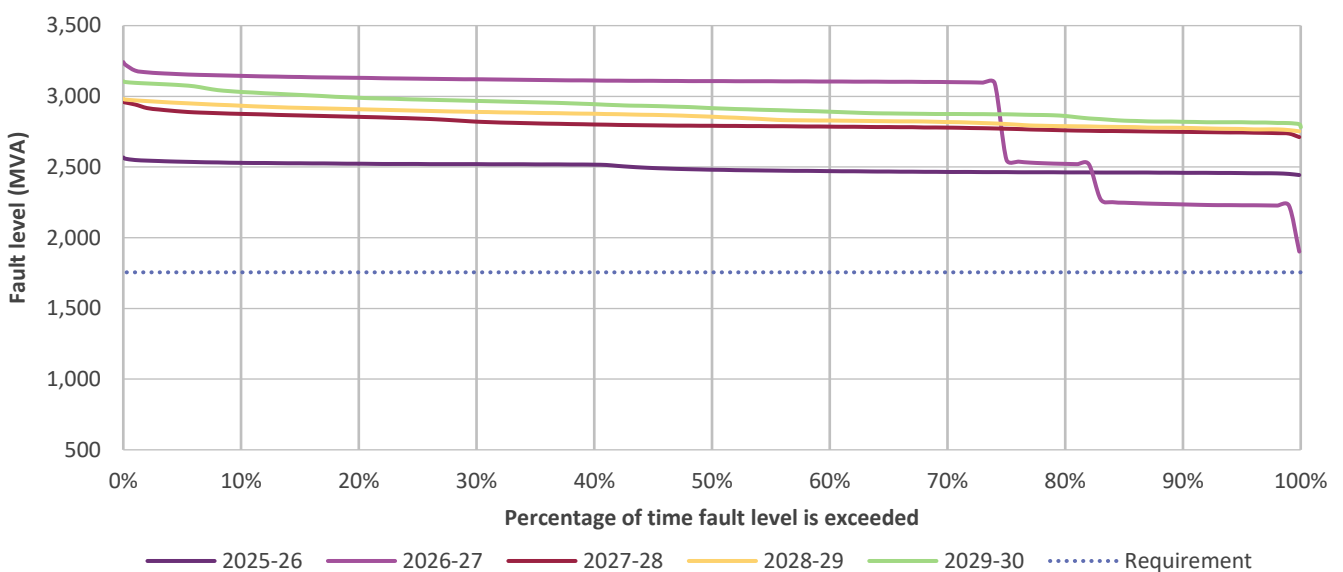
**Figure 14** shows the projected three phase fault level at the Buronga 220 kV node without the modelled parts of the RIT-T solution. Buronga does not show any deficits in the modelling horizon. **Figure 15** shows an increase in the projected fault levels after implementing the modelled parts of the RIT-T solutions.

**Table 22** shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The increase in fault level at Buronga is primarily due to nearby parts of the RIT-T solutions to manage fault levels at neighbouring system strength nodes.

**Figure 14 Buronga node fault level duration curves and minimum requirement**



**Figure 15 Buronga node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 22 Buronga node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Buronga 220 kV	Minimum fault level requirement (MVA)	17,55	1,755	1,755	1,755	1,755
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	2,420	1,855	2,639	2,562	2,629
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	2,443	1,902	2,712	2,752	2,804
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### A2.2.3.5 Inertia

AEMO modelled projected inertia under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>22</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in section A2.8.2.

AEMO assessed the expected levels of available inertia in New South Wales compared against the latest inertia requirements published in Section A2.2.1. The assessment considered the New South Wales portion of the system-wide inertia level, the islanded regional requirements, and the likelihood of the region becoming islanded. Section A2.2.1 provides further detail on the calculation and application of these inertia requirements.

As part of this assessment, AEMO determined that New South Wales is unlikely to become islanded<sup>23</sup>, given its strong interconnection with neighbouring regions. Consequently, AEMO's analysis focused on potential deficits relative to New South Wales' allocation of the system-wide inertia level (the inertia sub-network allocation).

### System-wide inertia level assessment for New South Wales

**Figure 16** and **Table 24** show the projected inertia levels for the New South Wales region in the Modified ESOO scenario. Under typical operation, available inertia is expected to fall below the sub-network allocation for a period of time in financial years 2027-28, 2028-29 and 2029-30, with inertia deficits of 4,236 MWs, 6,720 MWs and 3,099 MWs respectively.

AEMO also modelled inertia projections under an outlook which included some parts of the preferred options from each TNSP's system strength RIT-T (RIT-T outlook) where modelling information was available or a reasonable assumption could be made. The remainder of the preferred option was not modelled due to uncertainty with contracting or confidentiality. Through joint planning with TNSPs, AEMO has used the latest available modelling information including the most up to date

<sup>22</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station 'two-shifting', and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

<sup>23</sup> Historically AEMO has assessed a scenario where the NEM has separated with Queensland and New South Wales forming an island. For completeness, AEMO has confirmed that no inertia deficit exists for this scenario with updated inputs in 2024, however AEMO considers that the system-wide inertia level requirement assessment should supersede the need for this scenario in future.

location, timing, inertia, and fault level contribution for synchronous condensers based on current procurement status, and services from non-network synchronous condensers and synchronous generation where a proponent has been identified. The parts of Transgrid’s system strength RIT-T preferred solution modelled in the RIT-T outlook for inertia projections are detailed in **Table 23** below.

**Table 23 Parts of Transgrid’s System Strength RIT-T preferred option modelled in the RIT-T outlook for inertia projections**

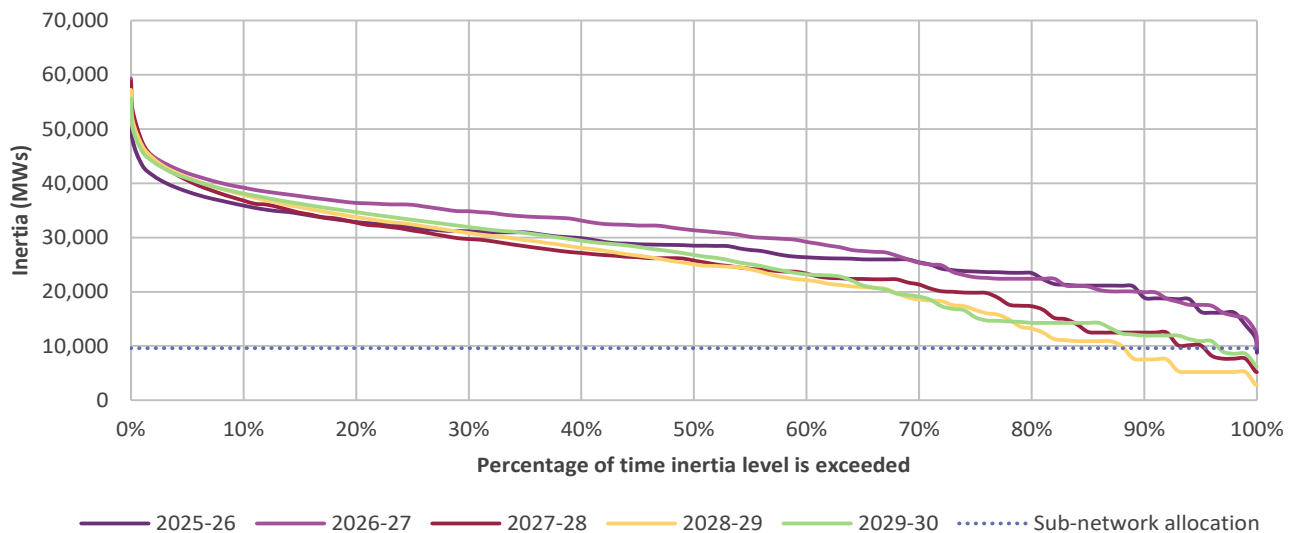
Part of RIT-T preferred solution <sup>A</sup>	Included in the RIT-T outlook for inertia projections?
<b>Ten network synchronous condensers</b>	Included with latest modelling information based on the outcome of a tender for synchronous condensers <sup>B</sup> .
<b>Non-network contracts with synchronous units</b>	Only one synchronous power station was included based on available information leading up to publication of this report. More contracts are expected in the final portfolio of non-network contracts upon completion of tendering.
<b>GFM BESS</b>	Not included in inertia projections as synthetic inertia constants have not been calculated.

A. Transgrid, *Meeting system strength requirements in New South Wales Project Assessment Conclusions Report*, 2025, at <https://www.transgrid.com.au/media/kfhd21bq/250812-transgrid-system-strength-pacr.pdf>.

B. See <https://www.transgrid.com.au/media-publications/news-articles/nsw-secures-critical-grid-stabilising-machines-to-support-renewables-rollout>.

The modelled parts of the RIT-T solutions address the inertia deficits in New South Wales from 2029-30, but residual deficits remain for 2027-28 and 2028-29 before their full deployment, as detailed in **Figure 17** and **Table 25**. This residual risk could be managed via contracts with synchronous generators. Transgrid has a binding inertia obligation to meet its inertia sub-network allocation from 2 December 2027.

**Figure 16 Projected inertia for the five-year outlook, Modified ESOO scenario, New South Wales**



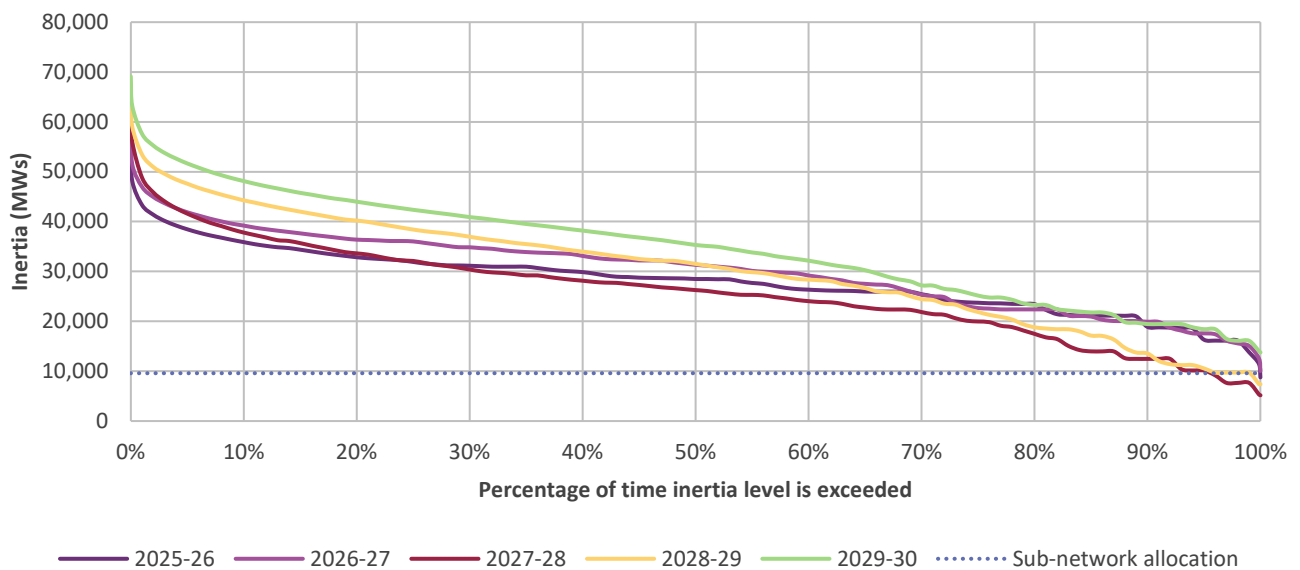
**Table 24 Inertia sub-network allocation and projections, Modified ESOO scenario New South Wales**

	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Inertia sub-network allocation (MWs)</b>	9,600	9,600	9,600	9,600	9,600
<b>Available inertia 99.87% of the time (MWs)</b>	11,480	12,552	5,364	2,880	6,501
<b>Inertia deficit (MWs)</b>	0	0	4,236	6,720	3,099
<b>NSCAS gap (Yes/No)*</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.

\*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

**Figure 17** Projected inertia for the five-year outlook, Modified ESOO scenario with modelled parts of the RIT-T solution, New South Wales



**Table 25** Inertia sub-network allocation and projections Modified ESOO scenario with modelled parts of the RIT-T solution, New South Wales

	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Inertia sub-network allocation (MWs)</b>	9,600	9,600	9,600	9,600	9,600
<b>Available inertia 99.87% of the time (MWs)</b>	11,480	12,552	5,364	7,380	14,001
<b>Inertia deficit (MWs)</b>	0	0	4,236	2,220	0
<b>NSCAS gap (Yes/No)*</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.  
 \*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

### Islanded inertia assessment for New South Wales

Due to New South Wales’ strong interconnections with neighbouring states, it is considered highly unlikely to become islanded. Accordingly, an islanded inertia assessment is not required.

#### A2.2.3.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in New South Wales. **Table 26** provides a comparison of binding hours and marginal values for the highest impact constraints observed<sup>24</sup>. All constraints with a marginal value exceeding \$60,000 per year have been discussed with Transgrid, and Transgrid has confirmed the status, project, control scheme, or other mitigation strategy if applicable or underway for each. These constraints are being monitored through Transgrid’s annual Transmission Annual Planning Report (TAPR) process, which may trigger action if market benefits exceed remediation costs.

<sup>24</sup> Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the NSCAS Description and Quantity Procedure, at [https://aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0](https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0).

**Table 26 New South Wales high-impact constraint summary for 2024 calendar year**

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
N>NIL_94T	Out= Nil, avoid O/L Molong to Orange North (94T) on trip of Nil, Feedback	31.8M (↑\$7.8M)	1,811.8	Committed project to address N>NIL_94T. Transgrid's 2025 TAPR details project "Increasing capacity for generation in the Molong and Parkes area" for which the RIT-T is complete and is in project delivery stage now.
N>>NIL_9XX_051	Out= NIL, avoid O/L Burrinjuck to Yass (970) on trip of Wagga to Lower Tumut (051) line, Feedback	20.2M (↑\$9.1M)	1,001.3	The current binding constraint will be improved following the commissioning of the committed transmission project HumeLink, which is planned for late 2026. This project should assist in elevating the current binding constraint. Other projects that can be considered that are likely to assist in removing this constraint are a Wagga – Yass line split scheme which may assist in the interim.
N>NIL_969	Out= Nil, avoid O/L Gunnedah to Tamworth (969) on trip of Nil, Feedback. Metering is used as specified in OM520 [Note: swamped with 96M or 9UJ or 9UH is O/S]	14.8M (↓\$4.5M)	1,249.3	Transgrid does not have a committed project in this revenue period to address the constraint. Transgrid has proposed a project in next revenue period (2028-2033) to address this need. It requires further load growth in Narrabri and Gunnedah.
N>NIL_9R6_991	Out= Nil, avoid O/L Wagga North to Wagga (9R6) 132kV line on trip of Wagga North to Murrumburrah (991) 132kV line, Feedback	10.4M (↑\$6M)	1,048.6	"Increase transfer capacity for renewable generation in the Wagga North areas." Project options include upgrading the 132 kV 9R5 and 9R6 lines to alleviate this constraint.
N>NIL_94K_1	Out= Nil, avoid O/L Suntop Tee to Wellington (94K/1) on trip of Nil, Feedback	4.3M (↓\$8.2M)	445.6	Transgrid have proposed a project to increase capacity for generation from Parkes to Wellington which will help alleviate this constraint.
N>NIL_9R5_9R6_N	Out= NIL, avoid O/L Wagga330 to Wagga North (9R5) 132kV line on trip of Wagga132 to Wagga North (9R6) 132kV line, Feedback	3.8M (↑\$3.8M)	26.1	"Increase transfer capacity for renewable generation in the Wagga North areas." Project options include upgrading the 132 kV 9R5 and 9R6 lines to alleviate this constraint.
N>NIL_9R6_9R5	Out= Nil, avoid O/L Wagga North to Wagga132 (9R6) on trip of Wagga North to Wagga330 (9R5) line, Feedback	3.7M (↓\$1.7M)	535.7	"Increase transfer capacity for renewable generation in the Wagga North areas." Project options include upgrading the 132 kV 9R5 and 9R6 lines to alleviate this constraint.
N^^^NIL_X5_xxx	Out= Nil, limit power flow on line X5 from Balranald to Darlington Point (X5) to avoid voltage collapse at Balranald for contingency trip of Bendigo to Shepparton 220kV line in NW Victoria	3.1M (↓\$4.4M)	501.8	To address the very high power flows in the 220 kV network, which are leading to severe under voltages at Balranald and issues with voltage stability limit on Darlington Point on a contingent trip of a transmission line in North West Victoria. "Relieving X5 voltage stability constraints" proposes to install a 220 kV 20 MVar capacitor bank to provide additional reactive support which improves the Darlington Point stability limit.
N>NIL_PKT_X_LV	Out= Nil, avoid O/L either Parkes 132kV/66kV Transformer on NIL trip, Feedback.	2.6M (↓\$0.1M)	468.7	AEMO expects constraint binding is driven by local generation of Parkes Solar Farm and local load. AEMO will continue to monitor this issue.
N>NIL_901	Out= Nil, avoid O/L West Wyalong to Temora 132kV (901) line on trip of Nil, Feedback	2.6M (↑\$2.3M)	333.6	AEMO expects constraint binding is driven by local generation of West Wyalong and Wyalong Solar Farm and local load. AEMO will continue to monitor this issue.
N>NIL_9R4_99A	Out= Nil, avoid O/L Finley to Mulwala 132kV line (9R4) on trip of Finley to Uranquinty (99A) line, Feedback	2.5M (↑\$2.3M)	410.9	AEMO expects constraint binding is driven by local generation. AEMO will continue to monitor this issue.

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
N>NIL_997_99A	Out= Nil, avoid O/L Corowa to Albury 132kV line (997/1) on trip of Finley to Uranquinty 132kV line (99A), Feedback	2.2M (↓\$2.3M)	215.8	This issue is managed by an existing protection scheme on nearby solar farms.
N>>NIL_YSTX_051	Out = Nil, avoid O/L of either Yass 132/330kV on trip of Wagga to Lower Tumut (051) line, Feedback	1.9M (↑\$0.5M)	233.6	Committed project to address N>NIL_94T. The latest Transgrid 2025 TAPR provides the advice on a project to alleviate this constraint. The project to improve thermal capacity is “Increasing capacity for generation in the Molong and Parkes area”. Transgrid has completed RIT-T for this project. It is in project delivery stage now.
N>NIL_BHTX_SF_TTS_HV	Out= NIL with one Broken Hill 220/22kV TX O/S (Note: only one TX can be I/S for system normal), avoid O/L remaining Broken Hill 220/22kV TX for contingency transfer tripping Broken Hill SF, (Note: Swamped when both TX1&2 I/S, Assumed 22kV CB 2112 I/S), FB	1.5M (↑\$1.5M)	25.9	The current binding constraint will be improved following the commissioning of the committed transmission project HumeLink, which is planned for late 2026. This project should assist in elevating the current binding constraint. Other projects that can be considered that are likely to assist in removing this constraint are a Wagga – Yass line split scheme which may assist in the interim.
N>>NIL_33_34	Out= Nil, avoid Bayswater to Liddell (33 or 34) O/L on loss of other Bayswater to Liddell (34 or 33), Feedback	1.4M (↑\$1.1M)	259.3	Transgrid has a proposed project to increase capacity for Central West Orana REZ generation which will help alleviate this constraint.
N>NIL_99F	Out= Nil, avoid O/L Narrandera to Uranquinty (99F) 132 kV line on trip of Nil, Feedback	1M (↑\$0.9M)	156.3	“Increase transfer capacity for renewable generation in the Wagga North areas.” Project options include upgrading the 132 kV 9R5 and 9R6 lines to alleviate this constraint.
N>>NIL_964_84_S	Out= NIL, avoid O/L Port Macquarie to Herons Creek Tee (964/2) on trip of Tamworth to Liddell (84) line, Feedback	0.9M (↑\$0.2M)	640.0	The following project proposed in 2024 TAPR to help improve this constraint has been removed in the 2025 TAPR, as the latest demand forecast does not show additional load increase beyond what has already been addressed for Stage 1 - “Maintaining reliable supply to Bathurst, Orange and Parkes areas Stage 2”. The scope of this project is to rebuild Wellington to Parkes 132 kV to double circuit. This is driven by future load growth in Parkes.”
N>NIL_COTX_LV	Out= Nil, avoid O/L either Corowa 22kV/132kV Transformer on NIL trip, Feedback. NOTE: System normal is only one transformer in service. 90% of Rating and no operating margin is used as per Essential Energy advice.	0.7M (↑\$0.6M)	95.9	This issue is managed by an existing protection scheme on nearby solar farms.
N::N_NIL_63	Out=Nil , limit Darlington Point to Wagga line (63) line flow to avoid voltage collapse at Darlington Point 132kV post contingency trip of line 63, Feedback	0.6M (↓\$0.1M)	78.0	Transgrid has procured services from existing operating BESS facilities in South West New South Wales to assist with under-voltages in the area and alleviate this constraint.
N>NIL_997/1_6Y	Out= NIL, avoid O/L Corowa to Albury (997/1) 132kV line on trip of Wagga to Walla Walla (6Y) 330kV line, Feedback	0.5M (↑\$0.5M)	32.6	This issue is managed by an existing protection scheme on nearby solar farms.
N>>NIL_966/1	Out= Nil, avoid O/L Metz Tee to Armidale (966/1) 132 kV line on trip of Nil, Feedback	0.4M (↑\$0.4M)	125.0	This issue is managed by an existing protection scheme on nearby solar farms.
N>NIL_9ML	Out= Nil, avoid O/L Crudine Ridge to Ilford Tee (9ML) on trip of Nil, Feedback. Metering is used as specified in OM520	0.4M (↓\$0.3M)	56.7	This issue is managed by an existing protection scheme on nearby solar farms.

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
N>NIL_94T_947	Out= Nil, avoid O/L Molong to Orange North (94T) on trip of Wellington to Orange North (947) line, Feedback	0.4M (↑\$0.2M)	48.3	Transgrid have proposed project to increase capacity for generation from Molong to Orange North which will help alleviate this constraint.
N>NIL_9GM	Out= Nil, avoid O/L Bango999 to Yass (9GM) on trip of Nil, Feedback	0.3M (↑\$0.2M)	33.3	This issue is managed by an existing protection scheme on nearby wind farm.
N>N-NIL_JUTX_LV	Out= Nil, avoid O/L Junee#3 132/66kV transformer on trip of Nil, Feedback. 90% of Rating is used as operating margin.	0.3M (↓\$0.1M)	49.5	Managed by Junee Solar Farm Transformer Overload Scheme.
N>NIL_983_987	Out= Nil, avoid O/L Tallawarra to Dapto (983) 132kV line on trip of Tallawarra to Dapto (987) 132kV line, Feedback	0.3M (↑\$0.3M)	73.3	AEMO expects constraint binding is driven by local generation. AEMO will continue to monitor this issue.
N^^V_NIL_1	Out = Nil, avoid voltage collapse at Southern NSW for loss of the largest Vic generating unit or Basslink	0.2M (↑\$0.2M)	209.7	AEMO expects binding performance of this constraint is dependent on periods of high import from New South Wales to Victoria. AEMO expects projects such as VNI West will improve binding performance of this constraint.
N>>NIL_86_85_S	Out= NIL, avoid O/L Armidale to Tamworth (86) on trip of Uralla to Tamworth (85) line, Feedback	0.2M (↑\$0.2M)	61.9	AEMO expects binding performance of this constraint will be improved with the operation of the Waratah Super Battery Special Integrity Protection Scheme (WSB SIPS).
N>>NIL_85_86_S	Out= NIL, avoid O/L Uralla to Tamworth (85) on trip of Armidale to Tamworth (86) line, Feedback	0.2M (↑\$0.2M)	76.3	AEMO expects binding performance of this constraint will be improved with the operation of the WSB SIPS.
N>NIL_997/2_99A	Out= NIL, avoid O/L Mulwala to Corowa (996/2) 132kV line on trip of Finley to Uranquinty (99A) 132kV line, Feedback	0.2M (↑\$0.1M)	26.3	AEMO expects constraint binding is driven by local generation. AEMO will continue to monitor this issue.
N>Q-NIL_757_758	Out= Nil, Avoid overloading 757 or 758 (T174 Terranora to H4 Mudgeeraba) 110kV line on trip of the other 758 or 757 (T174 Terranora to H4 Mudgeeraba line), Flow North, Feedback	0.2M (↑\$0.1M)	461.2	AEMO expects binding performance of this constraint is dependent on export level of Directlink from New South Wales to Queensland.
N>NIL_LSDU	Out = Nil, avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U6), Feedback	0.1M (↑\$0M)	242.3	AEMO expects the Directlink tripping scheme will manage this issue.
N^^V_NIL_ARWBBA	Out = Nil, avoid voltage collapse in southern NSW for loss of Ballarat to Waubra to Ararat 220kV lines (this also trips Waubra, Ararat and Crowlands, Bulgana and Murra Warra WFs)	0.1M (↑\$0.1M)	106.9	AEMO expects commissioning of Project EnergyConnect Stage 2 will improve binding performance of this constraint.

Note: From annual NEM Constraint Report, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams>. Constraints have been prioritised as per calendar 2024 data. Information sourced from Transgrid Annual Planning Report 2025, at [https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report\\_update\\_081025.pdf](https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf).

## A2.3 Queensland

- Delivery of the Gladstone Project transmission augmentation is critical to address emerging thermal and voltage risks following Gladstone Power Station retirement. Powerlink has already commenced this work<sup>25</sup>.
- Two inertia deficits have been identified, but have solutions underway:
  - 224 MWs from 2029-30 against the sub-network allocation. This deficit is fully mitigated by the synchronous condensers due to be installed as part of the Gladstone Project.
  - 3,084 to 4,484 MWs against the islanded requirements. This deficit is fully mitigated by the synchronous condensers as part of Powerlink's System Strength RIT-T, the existing clutch solution at Townsville power station, and expected contribution from existing GFM inverters.
- There are system strength deficits at Gin Gin, Greenbank, Lilyvale, and Western Downs nodes from 2027-28, ranging from 24 to 396 MVA. However, a residual deficit of 24-287 MVA at three nodes remains from 2027-28 which could be managed by contracts with generators or similar. This is described in the RIT-T but were not modelled due to insufficient information.
- AEMO has not made any updates to the system strength nodes or the minimum three phase fault level requirements, and the efficient level of system strength has been updated using the latest available information from the Draft 2026 ISP at the time of writing.
- AEMO has updated the secure and satisfactory inertia requirements to reflect an increasing amount of DPV and a better understanding of the interactions between synthetic inertia and FFR.

This section covers:

- inertia requirements, including the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level,
- system strength requirements, comprising the identification of system strength nodes, minimum fault level requirements over a 10-year horizon, and the 10-year forecast of IBR, used to determine the efficient level of system strength, and
- NSCAS assessment details, including considerations for both inertia and system strength projections against the requirements.

### A2.3.1 Inertia requirements

AEMO updated the satisfactory and secure inertia levels for Queensland based on the latest power system modelling inputs. AEMO also assessed Queensland as sufficiently likely to island from the remainder of the power system.

In addition to the system-wide inertia requirements, AEMO has determined minimum regional interconnected inertia levels for each region. While these levels are not regulatory obligations under NER 5.20B.2, they represent the practical amount of inertia that is required to be available within the region to withstand a contingency within that region, as detailed in Section A2.1.

<sup>25</sup> See <https://engage.powerlink.com.au/pti-gladstone-project>.

**Table 27** provides a summary of the inertia requirements for Queensland, including the assumed levels of 1-second FCAS available, the satisfactory and secure levels of inertia when planning for islanded operation, and the sub-network allocation of the system-wide level. Powerlink is required to ensure sufficient supplies are available to meet its inertia sub-network allocation from 2 December 2027.

**Table 27 Queensland inertia requirements from 2 December 2025 to 1 December 2035**

Quantity	Value
Assumed level of 1-second FCAS	527 MW
Satisfactory inertia level	13,000 MWs
Secure inertia level	14,700 MWs
Inertia sub-network allocation	10,500 MWs
Minimum regional interconnected inertia level	10,500 MWs
Likelihood of islanding	Likely <sup>A</sup>

### A2.3.1.1 Likelihood of islanding

**Table 28** presents the criteria assessed when determining the likelihood of the Queensland inertia sub-network islanding from the remainder of the system.

Queensland is considered likely to island. During a significant weather event around the QNI corridor such as a bushfire or damaging winds, or during a planned outage of a line in the QNI corridor, Queensland is at risk of islanding following a credible contingency.

**Table 28 Assessment of the likelihood of Queensland islanding**

Criterion	Queensland
Inertia levels compared to <i>secure inertia level</i>	Inertia levels forecast to be below the secure inertia level from 2028-29.
Inertia sub-network allocation	10,500 MWs
Existing interconnections	One 330 kV AC double-circuit and one DC link <i>connection</i> to New South Wales.
Future interconnections and status	QNI Connect: 330 kV AC double-circuit to New South Wales
History of islanding	May 2021 August 2018
Applicable control schemes	N/A
Likelihood of islanding after contingency event	Likely

### A2.3.1.2 Co-optimisation with contracted FFR and 1-Second FCAS

The amount of FFR available in the NEM has increased rapidly in the last half a decade due to significant battery connections. The 1-Second FCAS market was introduced as a mechanism for procuring FFR to meet the FOS.

The role of the inertia requirements is to slow down the change in frequency which occurs after a generation or load contingency until FCAS responds to contain and restore frequency. Following the staged introduction of 1-Second FCAS from 2023, less inertia has been required because FCAS now responds faster.

The NEM is now reaching a point where additional FFR may no longer allow the inertia requirements to decrease. In every region, the limiting factor in meeting the FOS under current levels of FFR is no longer the nadir but rather the RoCoF over

the first 300-500 ms. FFR is very effective at limiting the frequency nadir, but inertia is the most appropriate tool for limiting RoCoF over the first 300-500 ms.

In previous inertia reports, FFR curves have been used as a tool to determine the trade-off between inertia and FFR. Continued work studying this phenomenon in PSS®E shows these curves are unlikely to extrapolate to the levels of FFR currently available in the NEM. AEMO intends to consider the impact of additional FFR on inertia requirements on a case-by-case basis.

BESS are still able to contribute significantly to meeting the inertia requirements by providing synthetic inertia which is similarly effective as synchronous inertia in limiting RoCoF.

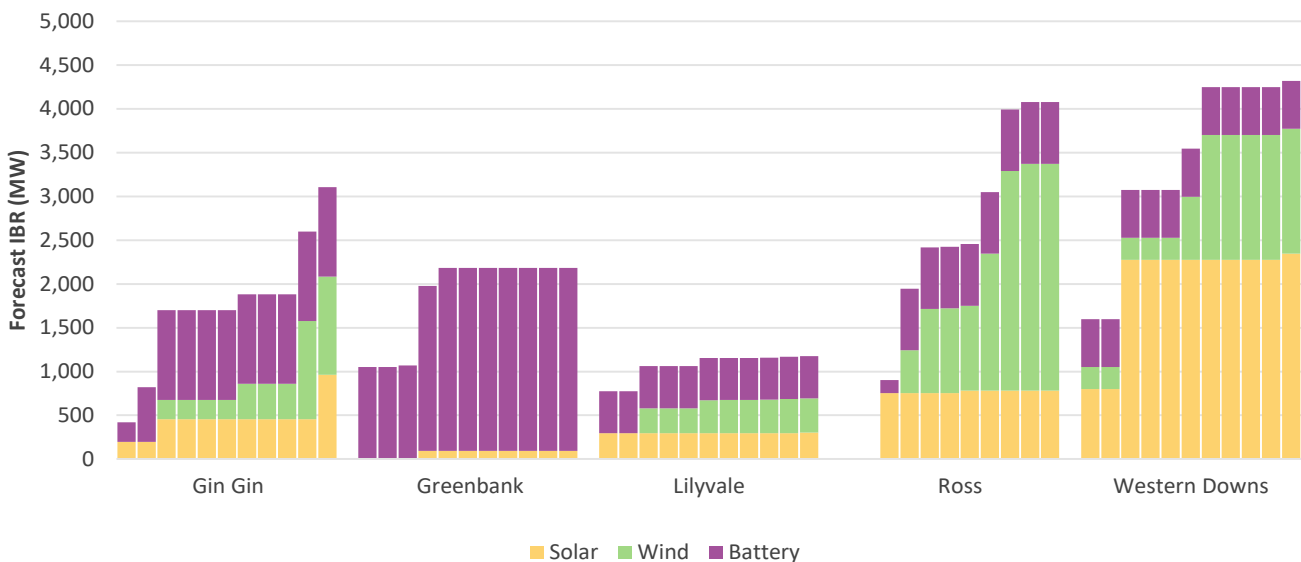
### A2.3.2 System strength requirements

AEMO has confirmed the system strength nodes, and their minimum fault level requirements continue to be maintained at the present values in the 2025 report. AEMO has also updated the IBR projections in Queensland used to determine the efficient level of system strength, based on the latest available preliminary information from the Draft 2026 ISP.

#### A2.3.2.1 Summary of IBR projections for Queensland

AEMO’s 10-year projection of the level and type of IBR and schedule 5.3a plant for Queensland system strength nodes under NER 5.20C.1(c)(2)(ii) is summarised in **Figure 18**. Details for each node are provided in Section A2.3.2.2. As defined in NER S5.1.14(a), **Figure 18** defines the ‘efficient level’ IBR forecast component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028.

**Figure 18** Forecasts of IBR and schedule 5.3a plant for 10 years from 2025-26, Queensland



This IBR forecast is primarily based on the Draft 2026 ISP modelling, which AEMO has allocated to specific nodes based on local network knowledge and engineering judgement. The Draft 2026 ISP is published after this system strength report<sup>26</sup> and projections may slightly differ to the preliminary results which informed this IBR forecast.

<sup>26</sup> The Draft 2026 ISP will be published on 10 December 2025 as per the ISP Timetable, at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>.

AEMO expects that Powerlink, as the SSSP in Queensland, may engage in joint planning with neighbouring SSSPs to identify any investment efficiencies when assessing the nature of solutions required to meet these requirements. AEMO supports SSSPs considering the latest available information and announcements to adjust this IBR forecast for use in their planning activities between publications of the system strength report, as outlined in Section A2.8.1.1.

### A2.3.2.2 Nodal IBR projections for Queensland

#### Gin Gin 275 kV

**Table 29** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 29 Gin Gin node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gin Gin 275 kV	Solar	1,005	198	198	456	456	456	456	456	456	456	456	964
	Wind	0	0	0	221	221	221	221	405	405	405	1,121	1,121
	Battery	67	222	622	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
	Total IBR	1,072	420	820	1,699	1,699	1,699	1,699	1,883	1,883	1,883	2,599	3,107

#### Greenbank 275 kV

**Table 30** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 30 Greenbank node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Greenbank 275 kV	Solar	15	0	0	0	94	94	94	94	94	94	94	94
	Wind	0	0	0	0	0	0	0	0	0	0	0	0
	Battery	259	1,052	1,052	1,070	1,884	2,091	2,091	2,091	2,091	2,091	2,091	2,091
	Total IBR	274	1,052	1,052	1,070	1,978	2,185	2,185	2,185	2,185	2,185	2,185	2,185

#### Lilyvale 132 kV

**0** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 31 Lilyvale node utility-scale IBR projections**

PNode	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Lilyvale 132 kV	Solar	428	296	296	296	296	296	296	296	296	296	296	303
	Wind	449	0	0	285	285	285	378	379	379	382	392	392
	Battery	0	480	480	480	480	480	480	480	480	480	480	480
	Total IBR	877	776	776	1,061	1,061	1,061	1,154	1,155	1,155	1,158	1,168	1,175

Ross 275 kV

Table 32 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 32 Ross node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Ross 275 kV	Solar	979	0	0	752	752	752	752	781	781	781	781	781
	Wind	391	0	0	0	490	962	970	970	1,564	2,507	2,592	2,592
	Battery	0	0	0	150	704	704	704	704	704	704	704	704
	Total IBR	1,370	0	0	902	1,946	2,418	2,426	2,455	3,049	3,992	4,077	4,077

Western Downs 275 kV

Table 33 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 33 Western Downs utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Western Downs 275 kV	Solar	1,914	799	799	2,274	2,274	2,274	2,274	2,274	2,274	2,274	2,274	2,346
	Wind	1,555	252	252	252	252	252	722	1,426	1,426	1,426	1,426	1,426
	Battery	529	548	548	548	548	548	548	548	548	548	548	548
	Total IBR	3,998	1,599	1,599	3,074	3,074	3,074	3,544	4,248	4,248	4,248	4,248	4,320

A2.3.2.3 Minimum fault level requirements for Queensland

The Queensland minimum fault level requirements under NER 5.20C.1(c)(2)(i) applicable for planning purposes over the next 10 years are summarised in Table 34 below. The minimum fault level requirements under NER 5.20C.1(c)(1) applicable for operational purposes over the next one year are in Section A2.9. As defined in NER S5.1.14(a), the values in the table define the minimum fault level component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028. No changes have been made to the minimum fault levels for Queensland in this 2025 system strength report.

**Table 34** Minimum fault level requirements for Queensland

Node	Pre-contingent (secure) minimum fault level (MVA)	Post-contingent minimum fault level (MVA)	Contingency applicable for post-contingent level	Last changed
Ross 275 kV	1,350	1,175	Ross – Strathmore 275 kV line	June 2021 <i>Notice of change to system strength requirement and shortfall at Ross</i>
Lilyvale 132 kV	1,400	1,150	Lilyvale – Broadsound 275 kV line	2020 <i>System Strength Report</i>
Gin Gin 275 kV	2,800	2,250	Woolooga – Gin Gin – Calliope River 275 kV line	2020 <i>System Strength Report</i>
Greenbank 275 kV	4,350	3,750	One Millmerran Power Station unit	2020 <i>System Strength Report</i>
Western Downs 275 kV	4,000	2,550	Braemar 275/330 kV transformer	2020 <i>System Strength Report</i>

#### A2.3.2.4 System strength nodes

No new nodes are under consideration in Queensland at this time.

#### A2.3.2.5 Critical planned outages

SSSPs are expected to consider critical planned outages in their proposed system strength solutions on a case-by-case basis<sup>27</sup>. AEMO has declared several critical planned outages as impactful for maintaining system strength in Queensland, and these are shown in **Table 35**. No changes to the list of critical planned outages in Queensland have been made in 2025.

**Table 35** Critical planned outages in Queensland for each system strength node

Affected node	Network outage	Reason for consideration as a critical outage
Lilyvale 132 kV	Lilyvale to Broadsound 275 kV line	Lilyvale 132 kV bus below minimum fault levels for another contingency. The outage conditions require radialising the Lilyvale 132 kV network.
	Lilyvale 275/132 kV transformer	
Lilyvale 132 kV	Stanwell to Broadsound 275 kV line	Loss of parallel feeder can result in impact on IBR in North Queensland with no direct 275 kV connection between Stanwell and Broadsound.

### A2.3.3 NSCAS assessment

AEMO assessed NSCAS needs in Queensland over a five-year outlook period, under a range of demand, generation, and network project assumptions. This section summarises the results of these assessments relating to:

- voltage control and thermal loading (Section A2.3.3.1),
- rapid voltage change (Section A2.3.3.2),
- reactive margin (Section A2.3.3.3),
- system strength, over a three-year period (Section A2.3.3.4),
- inertia, over a three-year period (Section A2.3.3.5), and
- market benefit ancillary services (MBAS, Section A2.3.3.6).

<sup>27</sup> AEMO, *System Strength Requirements Methodology*, Section 4.5, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/system-strength-requirements-methodology-v21.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/system-strength-requirements-methodology-v21.pdf).

Table 36 provides an overview of the core scenarios studied for Queensland. Section A2.8 provides further detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2025 NSCAS assessment.

**Table 36 Queensland NSCAS scenarios and outcomes**

Case	Scenario assumptions	Year of assessment	NSCAS gap
<b>Low demand (day)</b>	<i>Committed Projects Only</i>	2025-26	No new gaps identified
	<i>Committed Projects Only</i>	2030-31	No new gaps identified
	System typical	2025-26	No new gaps identified
	System typical	2030-31	No new gaps identified
<b>Low demand (night)</b>	<i>Committed Projects Only</i>	2025-26	No new gaps identified
	<i>Committed Projects Only</i>	2030-31	No new gaps identified
	System typical	2025-26	No new gaps identified
	System typical	2030-31	No new gaps identified
<b>High demand</b>	<i>Committed Projects Only</i>	2025-26	No new gaps identified
	<i>Committed Projects Only</i>	2030-31	Emerging risk
<b>System strength</b>	Modified ESOO scenario <sup>A</sup> ,	2025-26 to 2029-30	Deficit identified at Gin Gin, Greenbank, Lilyvale, and Western Downs, but no gap declared <sup>B</sup>
<b>System strength</b>	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	Deficit identified at Greenbank, Lilyvale, and Western Downs, but no gap declared <sup>B</sup>
<b>Inertia</b>	Modified ESOO scenario <sup>A</sup> ,	2025-26 to 2029-30	Deficit identified against the inertia sub network allocation and islanded requirements, but no gap declared <sup>B</sup>
<b>Inertia</b>	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	No deficit identified, but no gap declared <sup>B</sup>

A. Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station closure notification (see <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>).

B. This deficit will be partially addressed by the solutions modelled parts of the System Strength RIT-T, but some deficit remains which could be addressed via contracts with generators or similar. See Section A2.2.2 for details

### A2.3.3.1 Voltage control and thermal loading

AEMO has assessed expected voltage control and thermal loading issues in Queensland over a five-year outlook period, under both low and high demand scenarios. The analysis considered a range of region-specific network sensitivities and operating conditions to provide full coverage of heightened risk periods in Queensland under both minimum daytime, minimum nighttime and maximum demand.

#### Managing voltages in Southern Queensland

AEMO’s analysis confirms the previously declared voltage control gap in Southern Queensland is closed on the basis that the Belmont reactor and nearby committed BESS projects provide sufficient support to manage over voltage issues in this area. In December 2021, AEMO declared an immediate 120 megavolt amperes reactive (MVar) absorption NSCAS gap for voltage control in Southern Queensland. This issue related to night-time periods where demand was seen to be capacitive and availability of plant capable of absorbing excess reactive power was limited. In response to this declaration, Powerlink progressed a RIT-T comprised of an interim Network Support Agreement with nearby generation and installation of a 120 MVar reactor at Belmont.

## Emerging risk in managing thermal loading and voltages in Gladstone

AEMO has identified an emerging risk for congestion impacting supply to existing industrial load and projected load growth in Gladstone from early 2029. This relates to thermal overloads on 275 kV lines connecting Gladstone region to the broader network following the announced proposed closure of Gladstone Power Station.

Powerlink has identified a preferred transmission solution under the Queensland Priority Transmission Investment framework<sup>28</sup>. This solution features the staged development of the high capacity 275 kV network, to improve connectivity between central Queensland generation and Gladstone demand.

While the proposed network reconfiguration is expected to be sufficient to manage near-term thermal overloads following closure of Gladstone Power Station, continued demand growth beyond early 2029 may require additional long-term remediation. AEMO will continue to work with Powerlink to monitor the network needs as they approach.

### A2.3.3.2 Rapid voltage change

AEMO assessed the expected voltage change impacts of switching reactive plant in Queensland. **Table 37** summarises the results of this analysis indicating maximum voltage deviations for a given case, the appropriate IEC Standard<sup>29</sup>, and whether that standard is met. The results demonstrate that the standard is met for all conditions assessed.

Table 37 **Rapid voltage change results for reactive plant switching in Queensland**

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Minimum demand	Committed Projects Only	2025-26	No exceedances	No exceedances	No exceedances	3%-5%	Yes
	Committed Projects Only	2030-31	3.93	Boyne Island 132 kV	90 MVar capacitor at Boyne Island 132 kV		Yes
Maximum demand	Committed Projects Only	2025-26	No exceedances	No exceedances	No exceedances	3%-5%	Yes
	Committed Projects Only	2030-31	3.66	Boyne Island 132 kV	90 MVar capacitor at Boyne Island 132 kV		Yes

### A2.3.3.3 Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in Queensland are expected to remain above the system standard<sup>30</sup> of 1% of the local maximum fault level over the five-year outlook period.

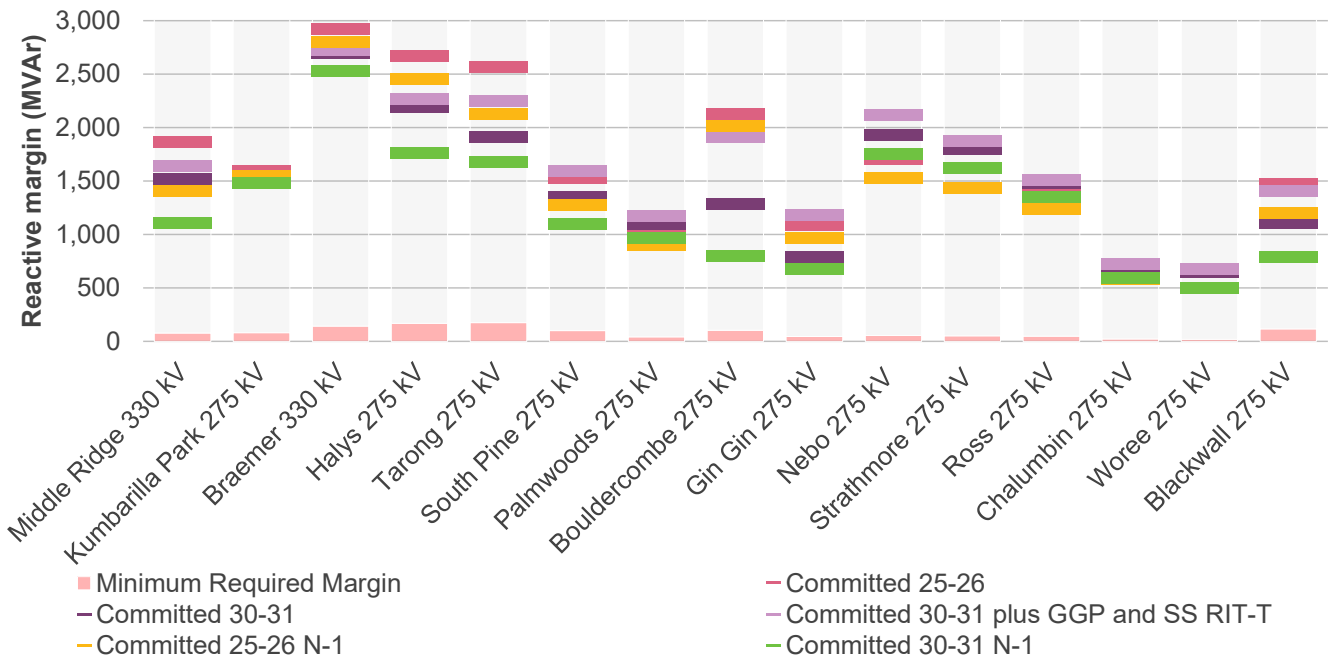
**Figure 19** summarises the results and indicates that all reactive margins are projected to meet the standard.

<sup>28</sup> Powerlink, June 2025, at [https://hdp-au-prod-app-pq-projects-files.s3.ap-southeast-2.amazonaws.com/8917/5014/1929/Gladstone\\_PTII\\_Final\\_Assessment\\_Report\\_web.pdf](https://hdp-au-prod-app-pq-projects-files.s3.ap-southeast-2.amazonaws.com/8917/5014/1929/Gladstone_PTII_Final_Assessment_Report_web.pdf).

<sup>29</sup> Requirements for voltage fluctuation are defined by NER S5.1a.5 and TR IEC 61000.3.7 Table 6, Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed four within a 24-hour period, with each change allowing a permissible variation of 3-5% for network elements operated at greater than 230 kV and 5-6% for network elements operated at voltages between 35 kV and 230 kV.

<sup>30</sup> Required reactive margin is defined by NER S5.1.8 as “not less than 1% of the maximum fault level (in MVA) at the connection point”. For the purposes of this assessment, the required reactive margin was calculated based on the 2025-26 maximum fault level.

**Figure 19 Minimum reactive margin (MVAR) observed for critical buses in Queensland**



#### A2.3.3.4 System strength

AEMO modelled projected fault levels under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>31</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of modelled parts of the System Strength RIT-T preferred options, as described in Section A2.8.2.

The expected three phase fault current at each system strength node in Queensland was compared against the latest minimum fault current requirements published in Section A2.3.2. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year<sup>32</sup>.

The results of this assessment are summarised in **Table 39**, and confirm that there are system strength deficits across Queensland from 2027-28, predominantly when coal generators in Queensland are offline, and increase in 2028-29 due to proposed closure of Gladstone Power Station. Deficits were projected for 2026-27 in the 2024 *System Strength Report* which are no longer projected in this 2025 report. This is largely due to Gladstone Power Station closing in March 2029<sup>33</sup>, which is different to the assumed 2024 ISP economic closure timing for Gladstone Power Station used in the 2024 *System Strength Report*.

<sup>31</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

<sup>32</sup> 99.87% is equivalent to three standard deviations above the mean. See [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc_lang=en).

<sup>33</sup> AEMO received a notice of closure for Gladstone Power Station stating intention for all units to cease supplying, acquiring, or trading in the market from March 2029, at <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

AEMO also modelled fault level projections under an outlook which included some parts of the preferred options from each TNSP’s system strength RIT-T (RIT-T outlook) where modelling information was available or a reasonable assumption could be made. The remainder of the preferred option was not modelled due to uncertainty with contracting or confidentiality. Through joint planning with TNSPs, AEMO has used the latest available modelling information including the most up to date location, timing, inertia, and fault level contribution for synchronous condensers based on current procurement status, and services from non-network synchronous condensers and synchronous generation where a proponent has been identified. The parts of Powerlink’s system strength RIT-T preferred solution modelled in the RIT-T outlook for fault level projections are detailed in **Table 38** below.

**Table 38 Parts of Powerlink’s System Strength RIT-T preferred option modelled in the RIT-T outlook for fault level projections**

Part of RIT-T preferred solution <sup>A</sup>	Included in the RIT-T outlook for fault level projections?
<b>Nine network synchronous condensers</b>	Included.
<b>Non-network contracts with synchronous units</b>	Not included as information was not available leading up to publication of this report.
<b>GFM BESS</b>	Not included in fault level projections due to current lack of evidence that GFM BESS can provide protection quality fault current.

A. Powerlink, *Addressing System Strength Requirements in Queensland from December 2025 Project Assessment Conclusions Report*, 2025, at <https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf>.

The modelled parts of the RIT-T solution mostly address the deficits identified, with some interim deficits remaining in 2028-29, which could be managed via contracts with generators or similar.

**Table 39 Queensland fault level requirements and identified deficits against the requirements**

System strength node	Fault level requirement (MVA)		Identified deficit in the Modified ESOO scenario (MVA)					Identified deficit in the Modified ESOO scenario with modelled parts of the RIT-T solutions (MVA)				
			2025-26	2026-27	2027-28	2028-29	2029-30	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Gin Gin 275 kV</b>	2,800	0	0	0	135	369	0	0	0	0	0	
<b>Greenbank 275 kV</b>	4,350	0	0	0	311	260	0	0	0	190	30	
<b>Lilyvale 132 kV</b>	1,400	0	0	24	96	187	0	0	24	35	0	
<b>Ross 275 kV</b>	1,350	0	0	0	0	0	0	0	0	0	0	
<b>Western Downs 275 kV</b>	4,000	0	0	86	396	115	0	0	82	287	0	

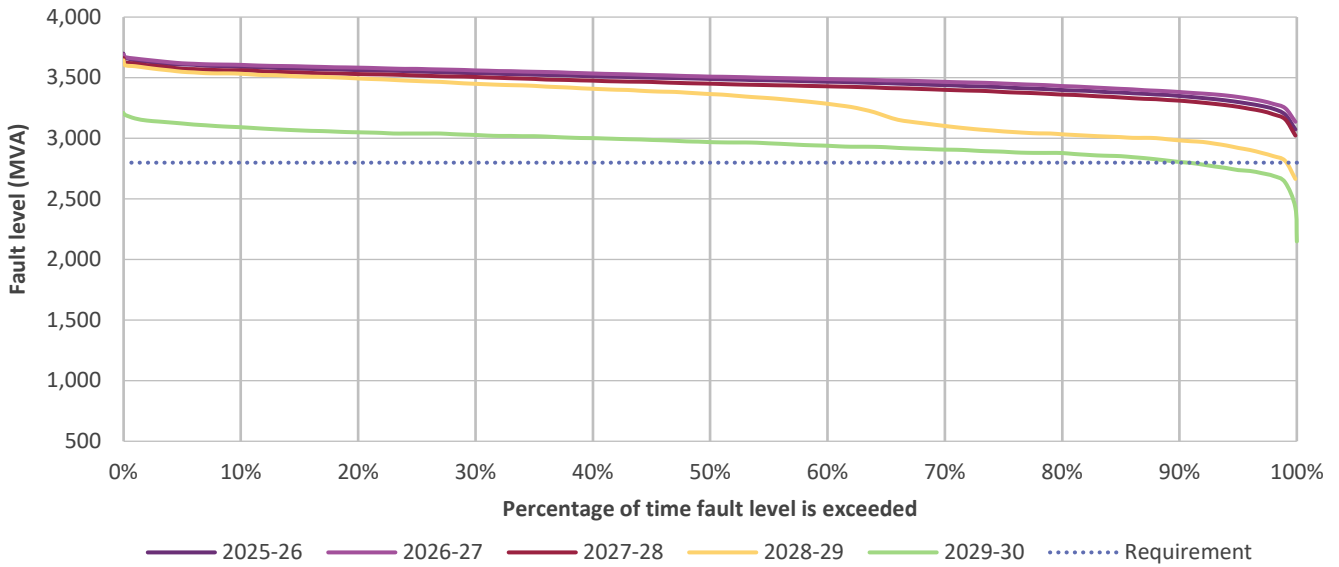
Section A2.3.2 provides additional detail on the calculation of fault level requirements. Detailed projected fault levels per system strength node are shown below with and without modelled parts of the RIT-T solutions.

### Gin Gin 275 kV

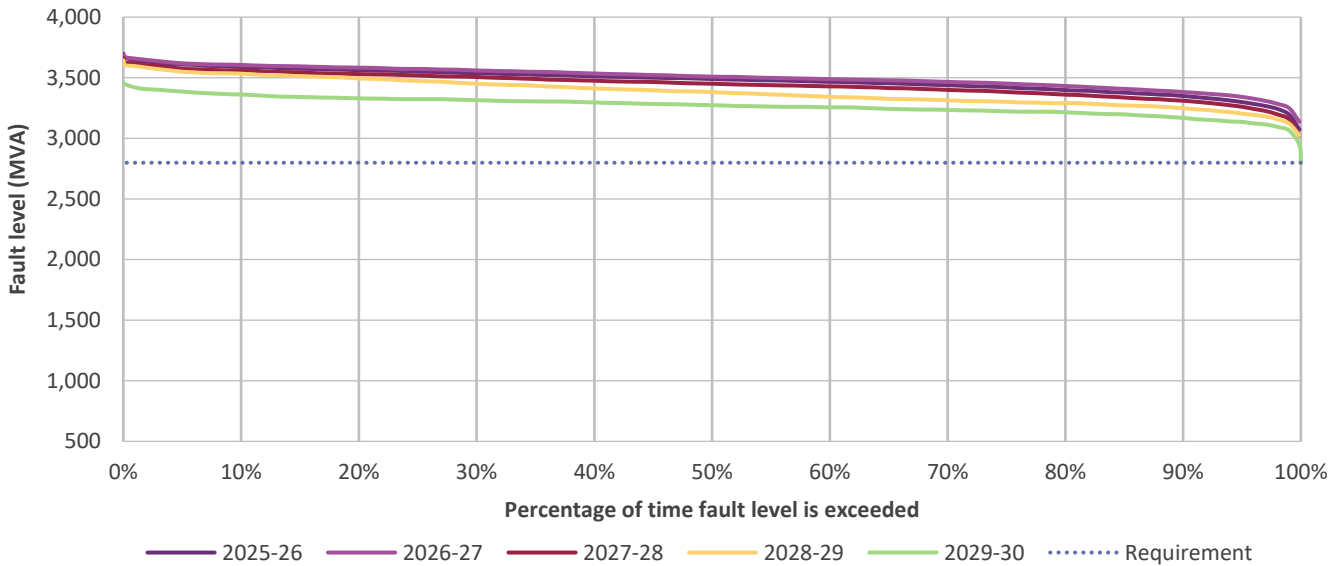
**Figure 20** shows the projected three phase fault level at the Gin Gin 275 kV node without the modelled parts of the RIT-T solution. The Gin Gin node sees a deficit in 2028-29 and 2029-30. **Figure 21** shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the previously seen deficits.

Table 40 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The deficits from 2028-29 are primarily due to retirement of Gladstone Power station, and they are expected to be addressed by the modelled parts of the RIT-T solutions.

**Figure 20 Gin Gin node fault level duration curves and minimum requirement**



**Figure 21 Gin Gin node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 40 Gin Gin node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Gin Gin 275 kV	Minimum fault level requirement (MVA)	2,800	2,800	2,800	2,800	2,800
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	3,074	3,136	3,024	2,665	2,431
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	3,074	3,136	3,024	3,026	2,947
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	135	369
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

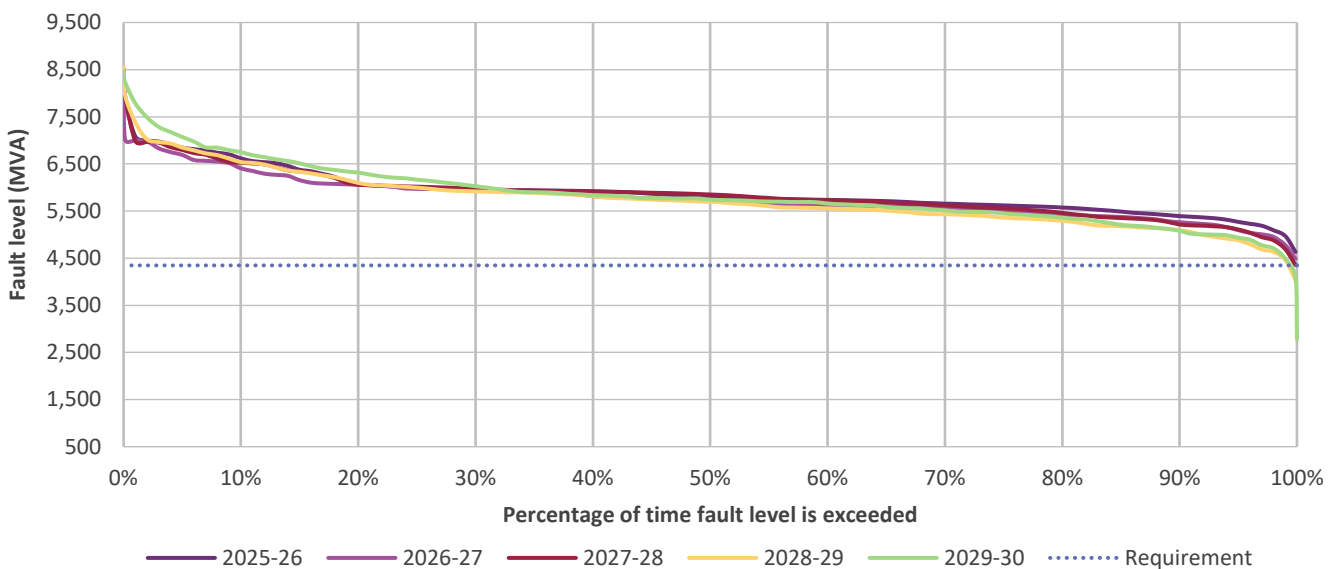
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Greenbank 275 kV

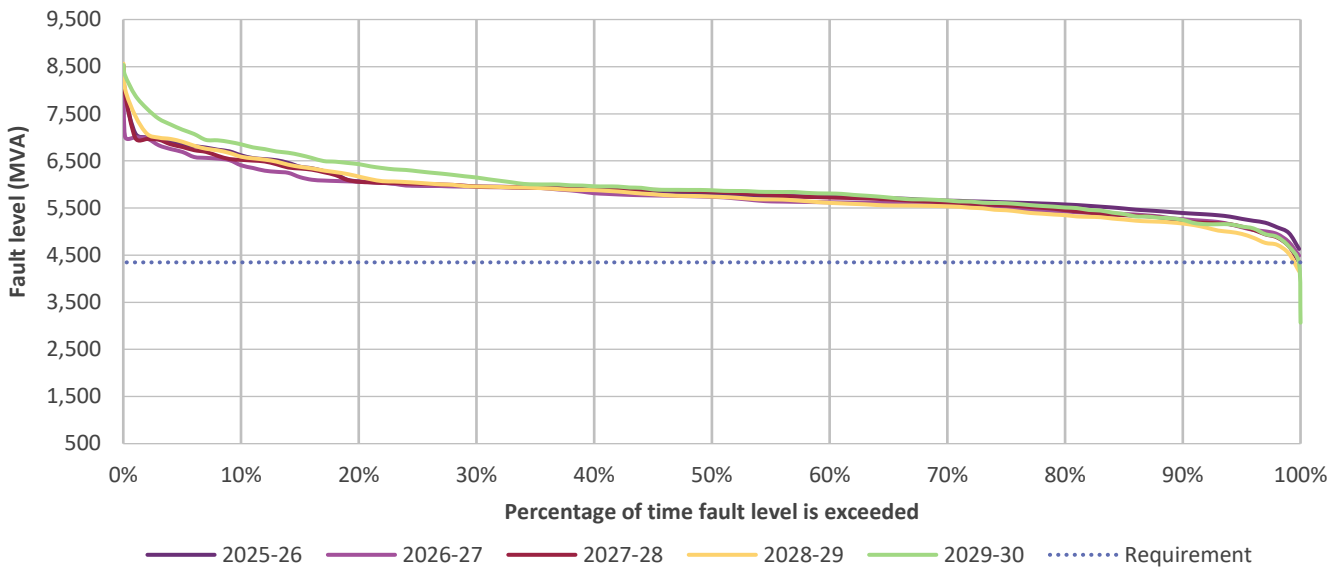
Figure 22 shows the projected three phase fault level at the Greenbank 275 kV node without the modelled parts of the RIT-T solution. Greenbank sees a deficit in 2028-29 and 2029-30. Figure 23 shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which reduces the previously seen deficits.

Table 41 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The deficits at Greenbank are reduced by the modelled parts of the RIT-T solutions with some remaining deficits. Powerlink is currently tendering for synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficit.

**Figure 22 Greenbank node fault level duration curves and minimum requirement**



**Figure 23 Greenbank node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 41 Greenbank node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Greenbank 275 kV	Minimum fault level requirement (MVA)	4,350	4,350	4,350	4,350	4,350
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	4,632	4,490	4,351	4,039	4,090
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	4,632	4,492	4,357	4,160	4,320
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	311	260
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	190	30
	NSCAS gap (Yes/No)*	No	No	No	No	No

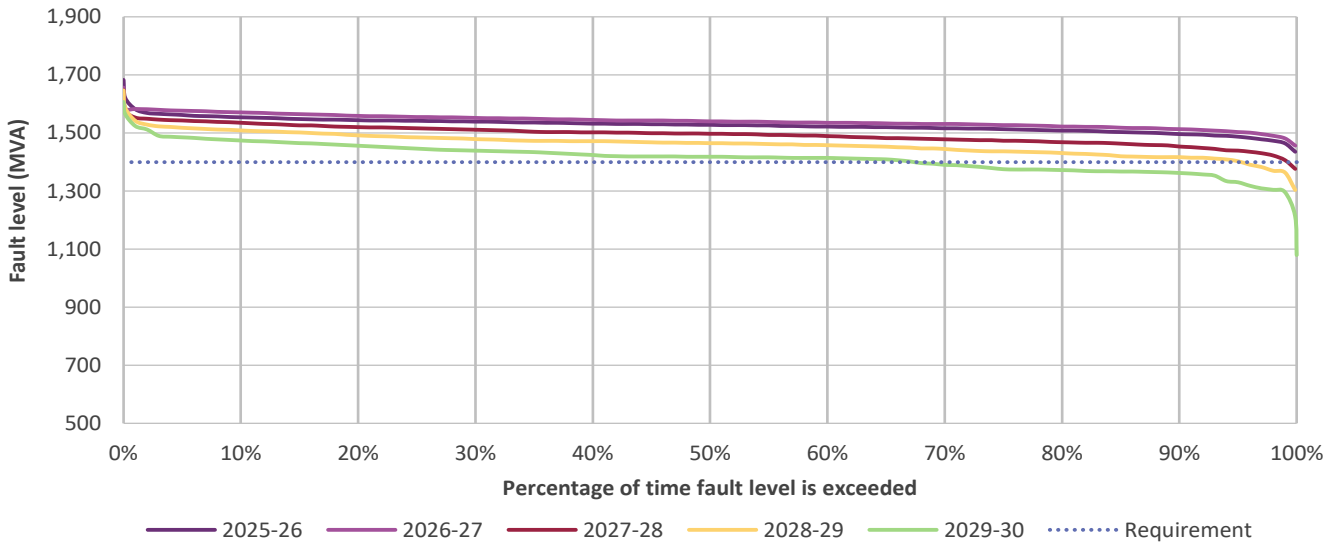
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Lilyvale 132 kV

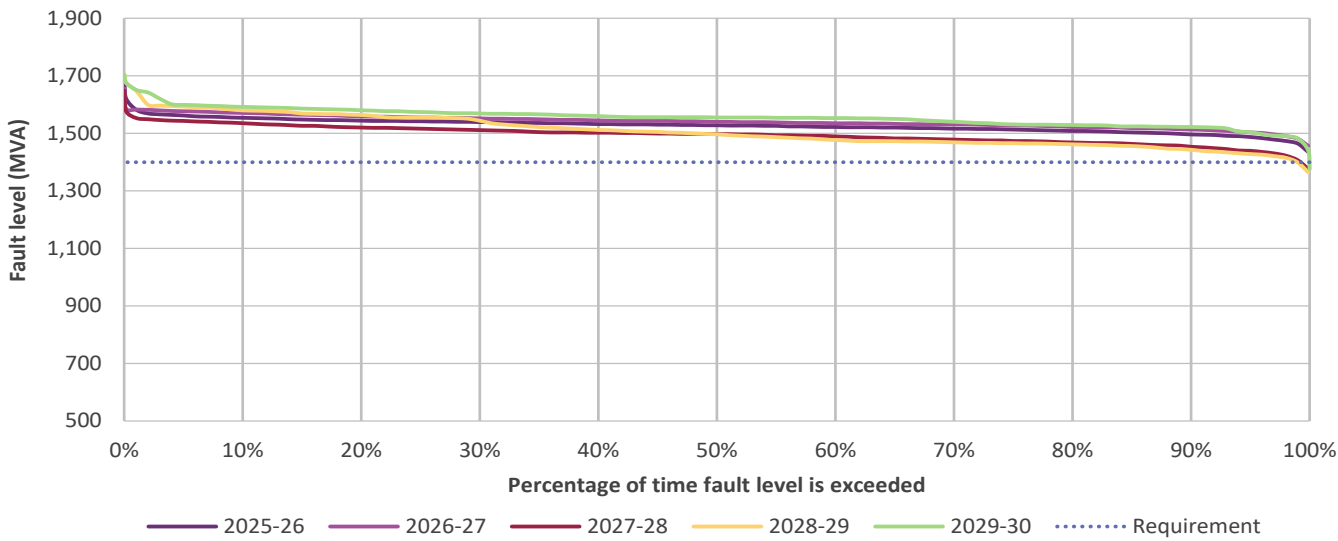
Figure 24 shows the projected three phase fault level at the Lilyvale 132 kV node without the modelled parts of the RIT-T solution. Lilyvale sees a deficit in 2027-28, 2028-29 and 2029-30. Figure 25 shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the deficit seen in 2029-30.

Table 42 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. By 2029-30, the deficits at Lilyvale are addressed by the modelled parts of the RIT-T solutions, with some remaining interim deficits in 2027-28 and 2028-29. Powerlink is currently tendering for synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficit.

**Figure 24 Lilyvale node fault level duration curves and minimum requirement**



**Figure 25 Lilyvale node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 42 Lilyvale node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Lilyvale 132 kV	Minimum fault level requirement (MVA)	1,400	1,400	1,400	1,400	1,400
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	1,435	1,456	1,376	1,304	1,213
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	1,435	1,456	1,376	1,365	1,441
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	24	96	187
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	24	35	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

Ross 275 kV

Figure 26 shows the projected three phase fault level at the Ross 275 kV node without the modelled parts of the RIT-T solution. Ross does not show any deficits in the modelling horizon. Figure 27 shows an increase in the projected fault levels after implementing the modelled parts of the RIT-T solutions.

Table 43 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. Powerlink has an existing contract in place for system strength to operate the Townsville GT in synchronous condenser mode through reversible clutch conversion. This is included in both sets of results with and without modelled RIT-T solutions, and plays a key role in maintaining minimum fault levels at Ross.

Figure 26 Ross node fault level duration curves and minimum requirement

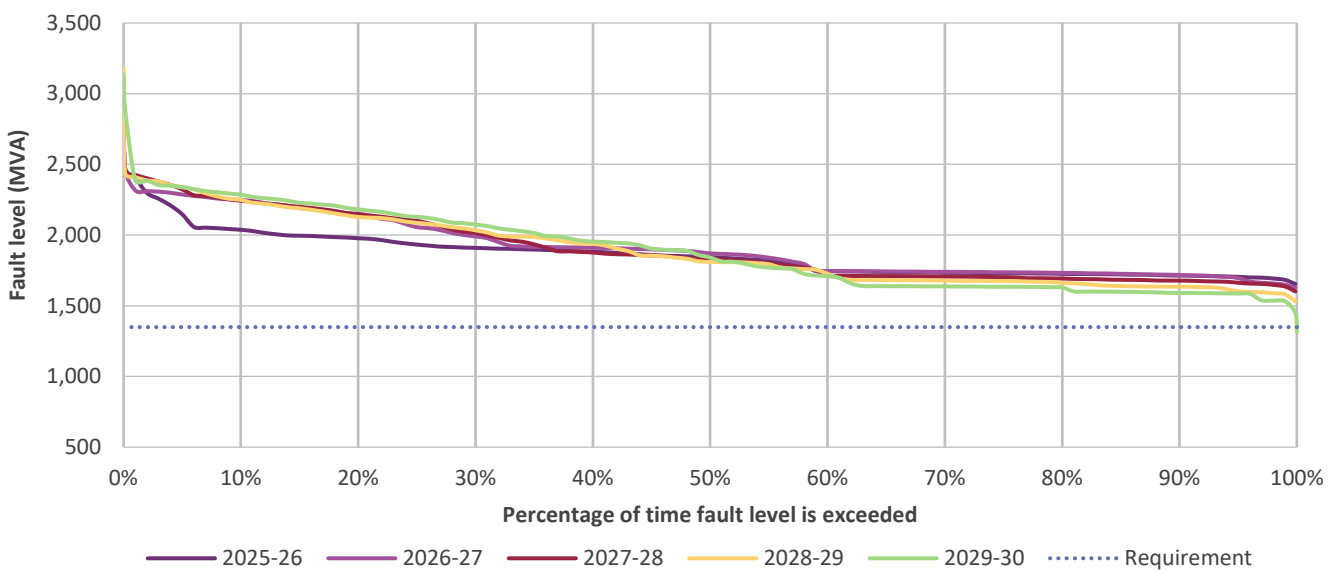
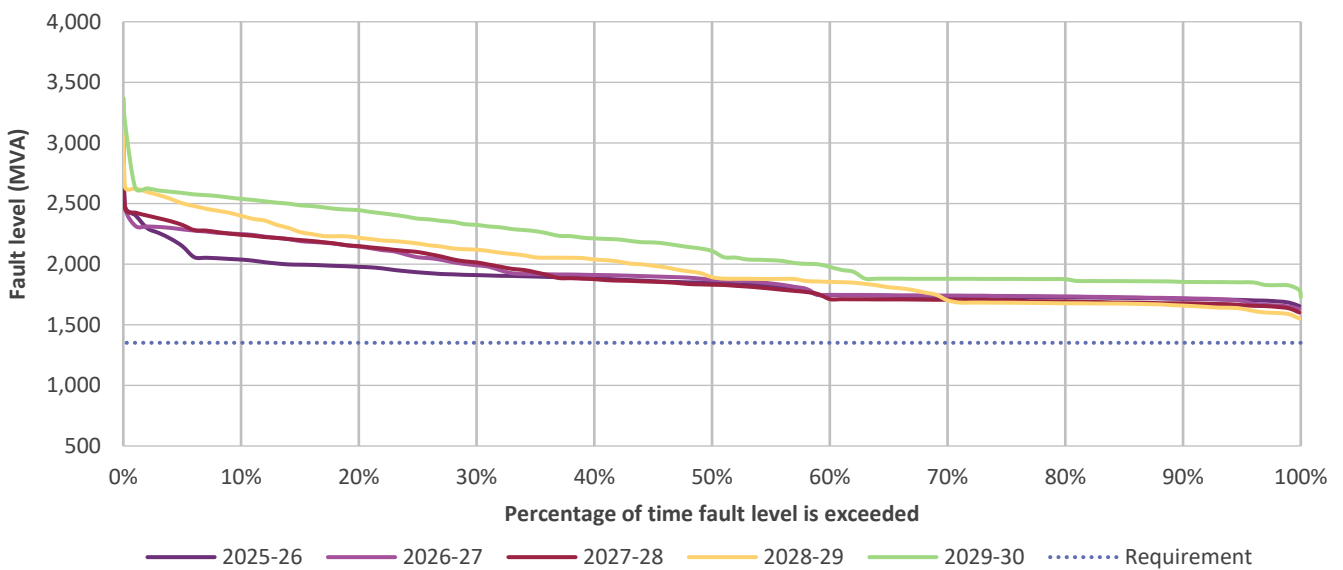


Figure 27 Ross node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution



**Table 43 Ross node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Ross 275 kV	Minimum fault level requirement (MVA)	1,350	1,350	1,350	1,350	1,350
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	1,654	1,629	1,602	1,533	1,449
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	1,654	1,629	1,602	1,552	1,787
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

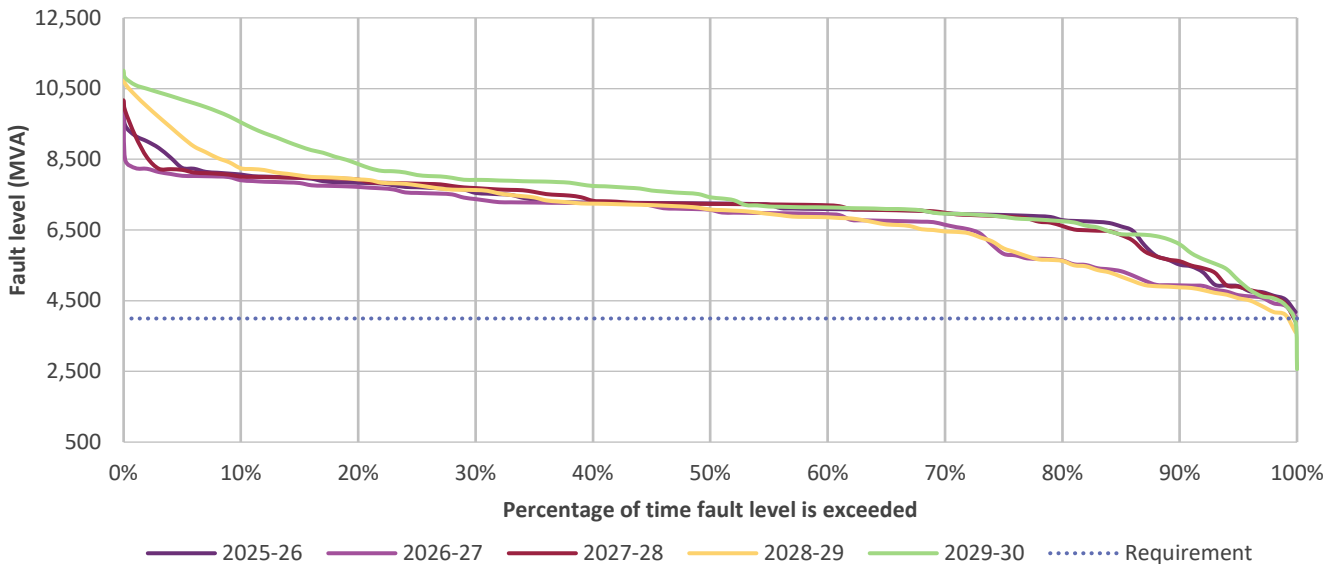
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Western Downs 275 kV

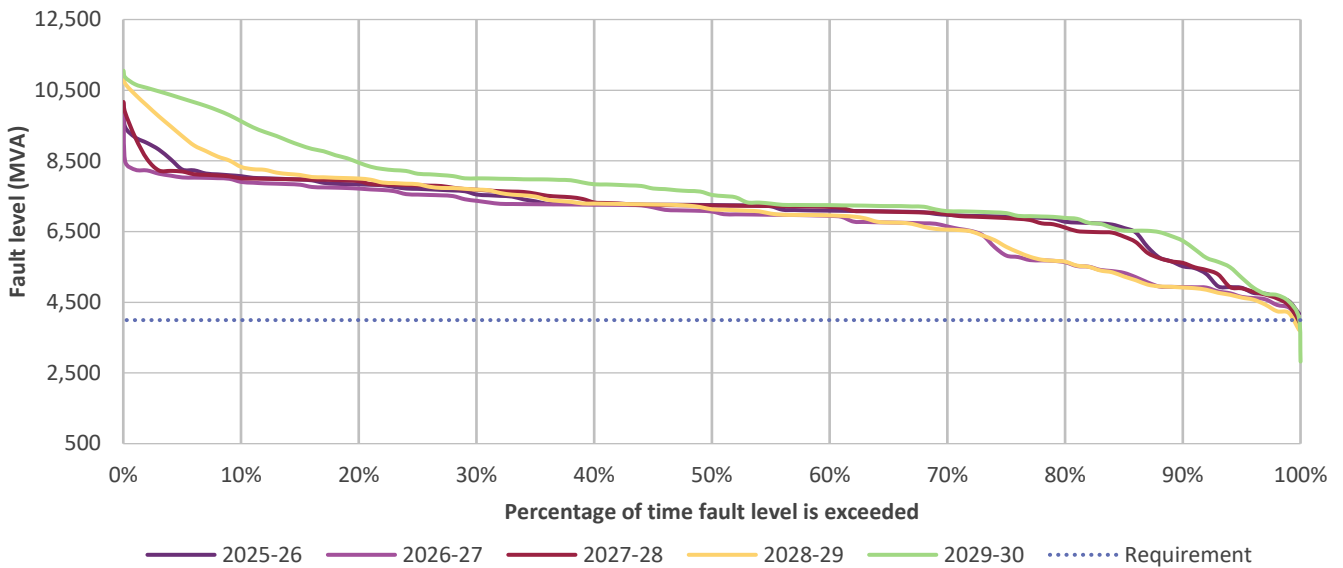
**Figure 28** shows the projected three phase fault level at the Western Downs 275 kV node without the modelled parts of the RIT-T solution. Western Downs sees a deficit in 2027-28, 2028-29 and 2029-30. **Figure 29** shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the deficit seen in 2029-30.

**Table 44** shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. By 2029-30, the deficits at Western Downs are addressed by the modelled parts of the RIT-T solutions, with some remaining interim deficits in 2027-28 and 2028-29. Powerlink is currently tendering for synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficit.

**Figure 28 Western Downs node fault level duration curves and minimum requirement**



**Figure 29 Western Downs node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 44 Western Downs node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Western Downs 275 kV	Minimum fault level requirement (MVA)	4,000	4,000	4,000	4,000	4,000
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	4,176	4,049	3,914	3,604	3,885
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	4,177	4,052	3,918	3,713	4,046
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	86	396	115
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	82	287	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### A2.3.3.5 Inertia

AEMO modelled projected inertia under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>34</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of modelled parts of the System Strength RIT-T preferred options.

AEMO assessed the expected levels of available inertia in Queensland compared against the latest inertia requirements published in Section A2.3.1. The assessment considered the Queensland portion of the system-wide inertia level, the islanded regional requirements, and the likelihood of the region becoming islanded. Section A2.3.1 provides further detail on the calculation and application of these inertia requirements.

<sup>34</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

AEMO has deemed Queensland as sufficiently likely to island on its own (see **Table 28**), so has assessed the region against both its portion of the system-wide inertia level (the inertia sub-network allocation), and its individual (islanded) secure level of inertia.

### System-wide inertia level assessment for Queensland

**Figure 30** and **Table 46** present the projected levels of inertia expected to be available under typical operation of the Queensland region over each of the next five years. This indicates an inertia deficit in Queensland of 224 MWs in financial year 2029-30 against the Queensland proportion of the system-wide inertia levels (the inertia sub-network allocation) for the Modified ESOO scenario.

AEMO also modelled inertia projections under an outlook which included some parts of the preferred options from each TNSP’s system strength RIT-T (RIT-T outlook) where modelling information was available or a reasonable assumption could be made. The remainder of the preferred option was not modelled due to uncertainty with contracting or confidentiality. Through joint planning with TNSPs, AEMO has used the latest available modelling information including the most up to date location, timing, inertia, and fault level contribution for synchronous condensers based on current procurement status, and services from non-network synchronous condensers and synchronous generation where a proponent has been identified. The parts of Powerlink’s system strength RIT-T preferred solution modelled in the RIT-T outlook for inertia projections are detailed in **Table 45** below.

**Table 45** Parts of Powerlink’s System Strength RIT-T preferred option modelled in the RIT-T outlook for inertia projections

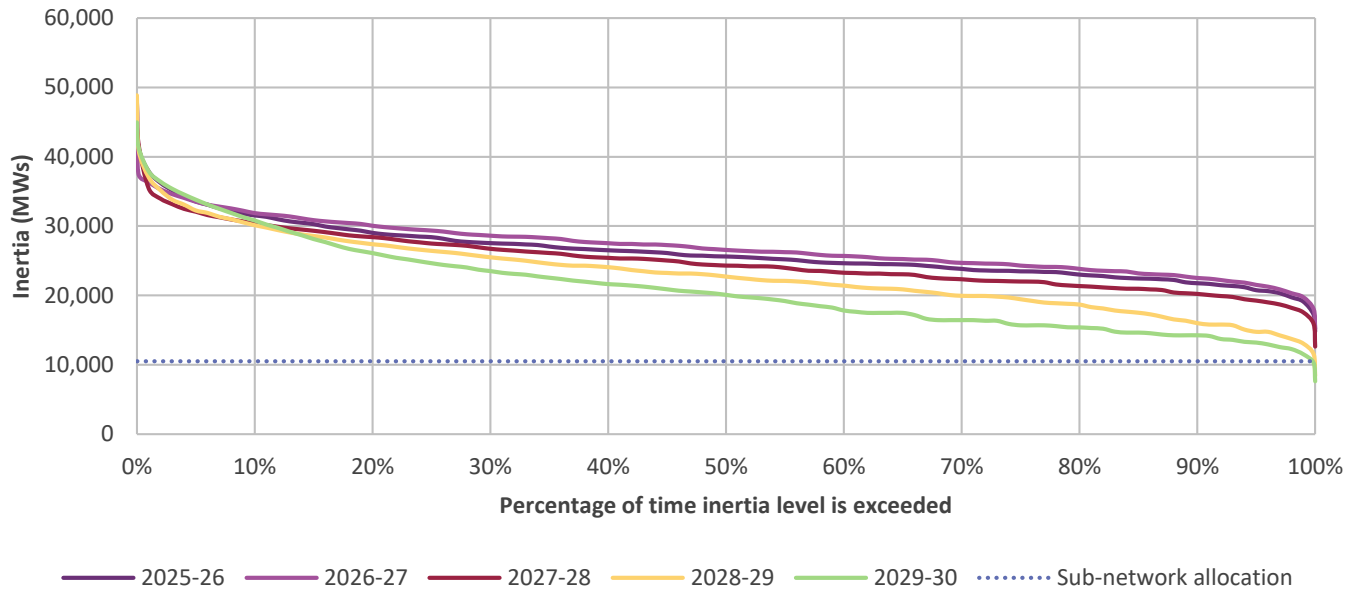
Part of RIT-T preferred solution <sup>A</sup>	Included in the RIT-T outlook for inertia projections?
Nine network synchronous condensers	Included.
Non-network contracts with synchronous units	Not included as information was not available leading up to publication of this report.
GFM BESS	Not included in inertia projections as synthetic inertia constants have not been calculated.

A. Powerlink, *Addressing System Strength Requirements in Queensland from December 2025 Project Assessment Conclusions Report*, 2025, at <https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf>.

If the modelled parts of Powerlink’s system strength RIT-T are considered, Queensland is expected to remain above the sub-network allocation, as detailed in **Figure 31** and **Table 47**.

Powerlink is required to ensure sufficient supplies are available to meet Queensland’s inertia sub-network allocation from 2 December 2027.

**Figure 30** Projected inertia for the five-year outlook, Modified ESOO scenario, Queensland

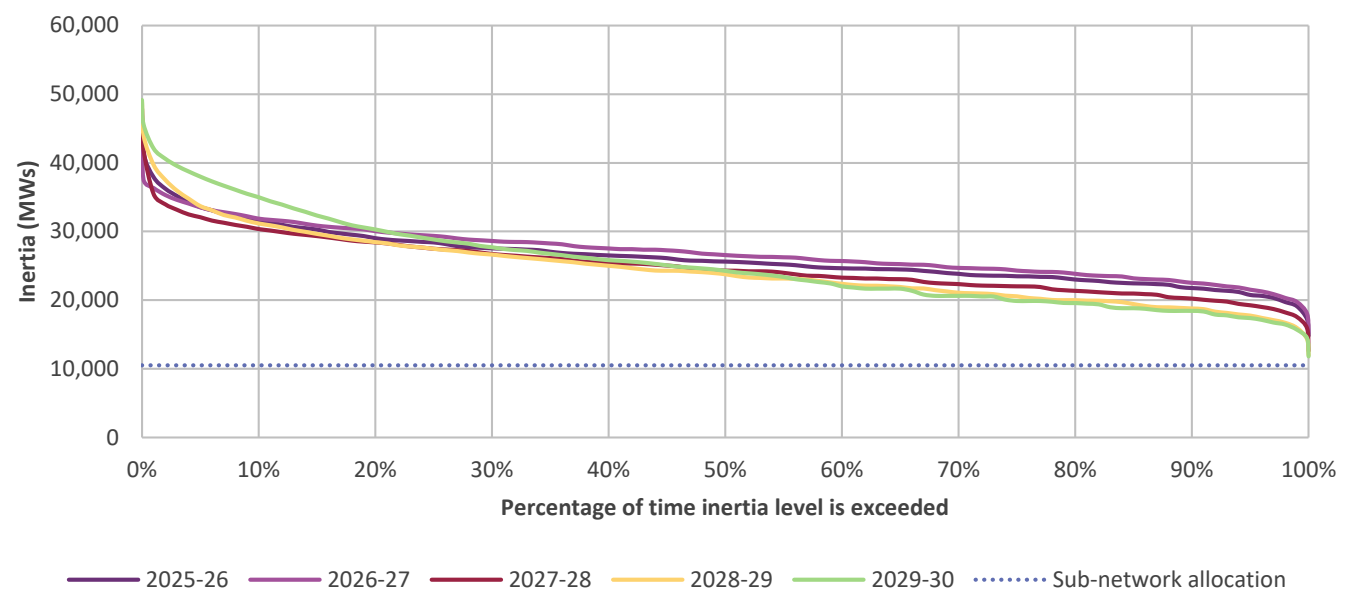


**Table 46** Inertia sub-network allocation and projections, Modified ESOO scenario, Queensland

	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Inertia sub-network allocation (MWs)</b>	10,500	10,500	10,500	10,500	10,500
<b>Available inertia 99.87% of the time (MWs)</b>	17,210	18,025	15,900	11,524	10,276
<b>Inertia deficit (MWs)</b>	0	0	0	0	224
<b>NSCAS gap (Yes/No)*</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.  
 \*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

**Figure 31** Projected inertia for the five-year outlook, Modified ESOO scenario with modelled parts of the RIT-T solution, Queensland



**Table 47 Inertia sub-network allocation and projections, Modified ESOO scenario with modelled parts of the RIT-T solution, Queensland**

	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Inertia sub-network allocation (MWs)</b>	10,500	10,500	10,500	10,500	10,500
<b>Available inertia 99.87% of the time (MWs)</b>	17,210	18,025	15,900	14,331	14,476
<b>Inertia deficit (MWs)</b>	0	0	0	0	0
<b>NSCAS gap (Yes/No)*</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.  
 \*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

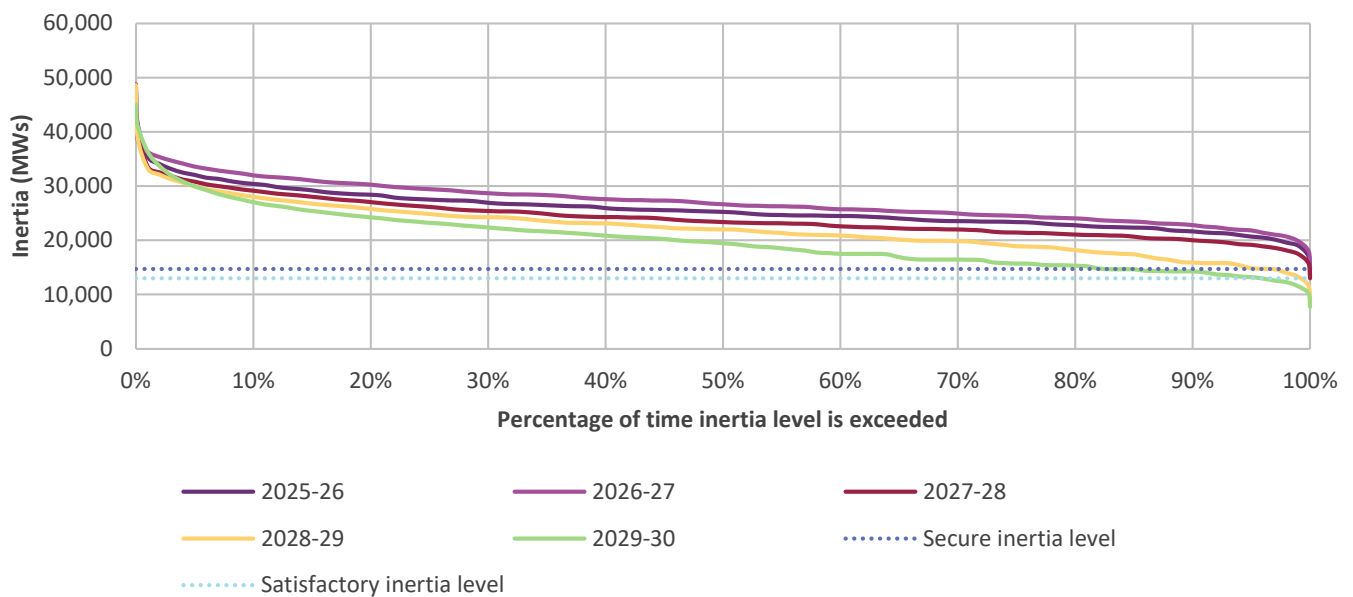
### Secure inertia requirements assessment for Queensland

**Figure 32** and **Table 48** show the projected inertia levels expected to be available under islanded operation, or credible risk of islanding of the Queensland region, in the modified ESOO scenario. Under typical operation, available inertia is expected to fall below the secure inertia level for islanded operation in financial year 2028-29 and 2029-30, with inertia deficits of 3,084 MWs and 4,484 MWs respectively.

When the modelled parts of Powerlink’s system strength RIT-T are included (as per **Table 45** above), the projected inertia deficits are expected to reduce. The 2028-29 deficit becomes 274 MWs, while the 2029-30 deficit is reduced to 284 MWs. The projections did not consider the availability of grid-forming inverters, which can provide synthetic inertia, nor the operation of the Townsville GT in synchronous condenser mode through the reversable clutch conversion. Inclusion of these would be expected to address the remaining deficits.

AEMO considers the inertia shortfall declared in the 2024 *Inertia Report*<sup>35</sup> closed, as there is sufficient inertia in 2025-26, 2026-27, and 2027-28.

**Figure 32 Projected inertia for the five-year outlook, Modified ESOO scenario, Queensland islanded case**



<sup>35</sup> See [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/2024-inertia-report](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report).

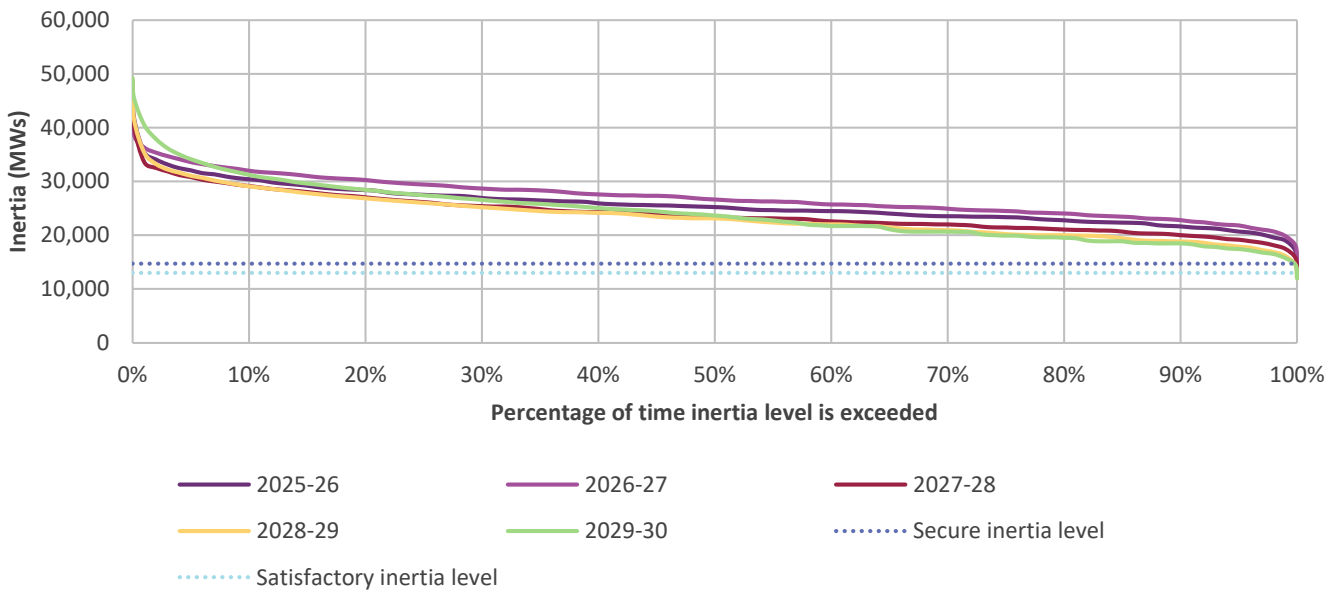
**Table 48 Secure inertia level and projections, Modified ESOO scenario, Queensland islanded case**

	2025-26	2026-27	2027-28	2028-29	2029-30
Assumed level of 1-second FCAS (MW)	375	375	375	375	375
Secure inertia level (MWs)	14,700	14,700	14,700	14,700	14,700
Available inertia 99.87% of the time (MWs)	17,054	18,034	15,776	11,616	10,216
Inertia deficit (MWs)	0	0	0	3,084	4,484
NSCAS GAP (Yes/No)*	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.

\*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

**Figure 33 Projected inertia for the five-year outlook, Modified ESOO scenario with modelled parts of the RIT-T solution, Queensland islanded case**



**Table 49 Secure inertia level and projections, Modified ESOO scenario with modelled parts of the RIT-T solution, Queensland islanded case**

	2025-26	2026-27	2027-28	2028-29	2029-30
Assumed level of 1-second FCAS (MW)	375	375	375	375	375
Secure inertia level (MWs)	14,700	14,700	14,700	14,700	14,700
Available inertia 99.87% of the time (MWs)	17,054	18,034	15,776	14,426	14,416
Inertia deficit (MWs) <sup>A</sup>	0	0	0	274 <sup>A</sup>	284 <sup>A</sup>
NSCAS gap (Yes/No) <sup>B</sup>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.

A. Contribution from GFM inverters and contracted plant for system strength addresses these deficits.

B. NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

### A2.3.3.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Queensland. **Table 50** provides a comparison of binding hours and marginal values for the highest impact constraints observed<sup>36</sup>.

All constraints with a marginal value exceeding \$60,000 per year have been discussed with Powerlink, and Powerlink has confirmed the status, project, control scheme, or other mitigation strategy if applicable or underway for each. These constraints are being monitored through Powerlink's annual TAPR process, which may trigger action if market benefits exceed remediation costs.

**Table 50 Queensland high-impact constraint summary for 2024 calendar year**

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	Comments
Q>NIL_YLMR	Out= Nil, avoid overload on 110kV feeders between Yarranlea and Middle Ridge(733/1 and 734/1), Feedback	1.9M (↓\$5.5M)	225.8	AEMO expects constraint binding is driven by local generation of Yarranlea and Maryborough solar farm. AEMO will continue to monitor this issue.
Q>NIL_TV66	Out=Nil, limit Sun metals SF and Mt Stuart GTs to avoid over load on 66kV feeders on trip of one of the 66kV feeders in the Townsville area	1.4M (↑\$1.4M)	43.5	AEMO expects constraint binding is driven by local generation. AEMO will continue to monitor this issue.
Q>NIL_DRCLCB_NIL	Out= Nil, avoid OL on 7490 or 7491 (T280 Drillham to T194 Columboola) 132kV feeder, NIL trip. Feedback	0.7M (↑\$0.5M)	48.8	AEMO expects constraint binding is driven by local generation of Dulacca wind farm and Roma gas turbines. AEMO will continue to monitor this issue.
Q_NIL_STRGTH_HAUSF	Out = Nil, limit Haughton solar farm output depends on the number units online in Stanwell, Callide B, Callide C, generators and Haughton Syncon, North Queensland demand. Zero if it does not meet the condition.	0.4M (↑\$0.3M)	39.8	This constraint manages system strength requirements for power system security in FNQ.
Q>NIL_EMCM_6056	Out= NIL, avoid thermal overload on Emerald to Comet (6056) 66 kV Feeder	0.3M (↓\$0.7M)	304.3	AEMO expects constraint binding is driven by local generation of Dulacca wind farm and Roma gas turbines. AEMO will continue to monitor this issue.
Q>NIL_EMBW_EMLV_DS	Out= Nil, limit Emerald SF to 40MW to avoid overload on Emerald - Lilyvale 66kV line on trip of Emerald - Comet - Blackwater 66kV line (6056 or 6011), swamp if Emerald CBs S612,S610 and Blackwater CB S605 are closed (DS only)	0.2M (↑\$0.1M)	45.8	AEMO expects this constraint will bind under scenarios where Emerald solar farm is dispatched greater than 40 MW and is radially supplying Lilyvale. AEMO is not aware of any projects in place to alleviate this constraint but will continue to monitor this issue.
Q>>NIL_BCCP_RGLC	Out= Nil, avoid O/L Raglan to Larcom Creek (8875) on trip of Bouldercombe to Calliope River (812) line, Feedback	0.1M (↑\$0.1M)	26.8	The Gladstone Project is expected to assist with this constraint. This project is being progressed by Powerlink.

Note: From annual NEM Constraint Report, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams>. Constraints have been prioritised as per calendar year 2024 data.

<sup>36</sup> Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is available in the NSCAS Description and Quantity Procedure, at [https://aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0](https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0).

## A2.4 South Australia

- AEMO has identified improvement in the previously declared voltage control gap; this gap will be closed upon installation of remaining reactors in Adelaide region. ElectraNet is remediating this issue via installation of new switched reactors in the Adelaide and South East regions. Three of six reactors have been installed, with the remaining three expected to be in service by October 2027. AEMO is progressing options to manage this gap through operational measures until the completion of the remaining reactor commissioning.
- No inertia deficits have been identified.
- No system strength deficits have been identified.
- AEMO has not made any updates to the system strength node or the minimum three phase fault level requirements, and the efficient level of system strength has been updated using the latest available information from the Draft 2026 ISP at the time of writing.
- AEMO has not made any updates to the inertia requirements.

This section covers:

- inertia requirements, including the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level over a 10-year horizon,
- system strength requirements, comprising the identification of system strength nodes, minimum fault level requirements over a 10-year horizon, and the 10-year forecast of IBR, used to determine the efficient level of system strength, and
- NSCAS assessment details, including considerations for both inertia and system strength projections against the requirements.

### A2.4.1 Inertia requirements

AEMO has confirmed that the inertia requirements for South Australia remain unchanged this year. ElectraNet is required to ensure sufficient inertia services are available to meet its *sub-network allocation* from 2 December 2027.

In addition to the system-wide inertia requirements, AEMO has determined *minimum regional interconnected inertia levels* for each region. While these levels are not regulatory obligations under NER 5.20B.2, they represent the practical amount of inertia that is required to be available within the region to withstand a contingency within that region, as detailed in Section A2.1.

**Table 51** provides a summary of the *inertia requirements* for South Australia, including the assumed levels of 1-second FCAS available, the satisfactory and secure levels of inertia when planning for islanded operation, and the sub-network allocation of the system-wide level.

**Table 51 South Australia inertia requirements from 2 December 2025 to 1 December 2035**

Quantity	Value
Assumed level of 1-second FCAS	403 MW
Satisfactory inertia level	4,100 MWs
Secure inertia level	5,600 MWs
Inertia sub-network allocation	4,300 MWs
Minimum regional interconnected inertia level	1,800 MWs
Likelihood of islanding	Likely <sup>A</sup>

A. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of Project EnergyConnect Stage 2 and necessary protection schemes are in place to manage the non-credible loss of either Project EnergyConnect itself or the Heywood interconnector.

#### A2.4.1.1 Likelihood of islanding

**Table 52** presents the criteria assessed when determining the likelihood of the South Australia inertia sub-network islanding from the remainder of the system.

South Australia is considered likely to island until Project EnergyConnect Stage 2 is completed (November 2027), including commissioning of control schemes to manage loss of a double circuit line in the Heywood or Project EnergyConnect corridors. Prior to completion of Project EnergyConnect Stage 2, South Australia is at risk of islanding following a credible contingency whenever a significant weather event such as a bushfire or damaging winds occurs near the Heywood corridor, or during a planned outage of a line in the Heywood corridor.

**Table 52 Assessment of the likelihood of South Australia islanding**

Criterion	South Australia
Inertia levels compared to secure inertia level	Inertia levels forecast to be above the secure inertia level (including contribution from GFMs) from 2025-26 until Project EnergyConnect Stage 2 is commissioned in 2027-28.
Inertia sub-network allocation	4,300 MWs
Existing interconnections	One 275 kV AC double-circuit to Victoria. One 330 kV AC single-circuit to New South Wales One DC link to Victoria.
Future interconnections and status	Project EnergyConnect stage 2: 330 kV AC double-circuit to New South Wales
History of islanding	November 2022 March 2020 January 2020 November 2019 August 2018 December 2016 September 2016 November 2015
Applicable control schemes	Future Project EnergyConnect Stage 2 control schemes to avoid islanding South Australia
Likelihood of islanding after contingency event	Plausible until Project EnergyConnect Stage 2 and associated control schemes are commissioned.

#### A2.4.1.2 Co-optimisation with contracted FFR and 1-Second FCAS

The amount of FFR available in the NEM has increased in the last half a decade due to significant battery connections. The 1-Second FCAS market was introduced as a mechanism for procuring FFR to meet the FOS.



The role of the inertia requirements is to slow down the change in frequency which occurs after a generation or load contingency until FCAS responds to contain and restore frequency. Following the staged introduction of 1-Second FCAS from 2023, less inertia has been required because FCAS now responds faster.

The NEM is now reaching a point where additional FFR may no longer allow the inertia requirements to decrease. In every region, the limiting factor in meeting the FOS under current levels of FFR is no longer the nadir but rather RoCoF over the first 300-500 ms. FFR is very effective at limiting the frequency nadir, but inertia is the most appropriate tool for limiting RoCoF over the first 300-500ms.

In previous inertia reports, FFR curves have been used as a tool to determine the trade-off between inertia and FFR. Continued work studying this phenomenon in PSS®E shows these curves are unlikely to extrapolate to the levels of FFR currently available in the NEM. AEMO intends to consider the impact of additional FFR on the inertia requirements on a case-by-case basis.

BESS are still able to contribute significantly to meeting the inertia requirements by providing synthetic inertia which is similarly as effective as synchronous inertia in limiting RoCoF.

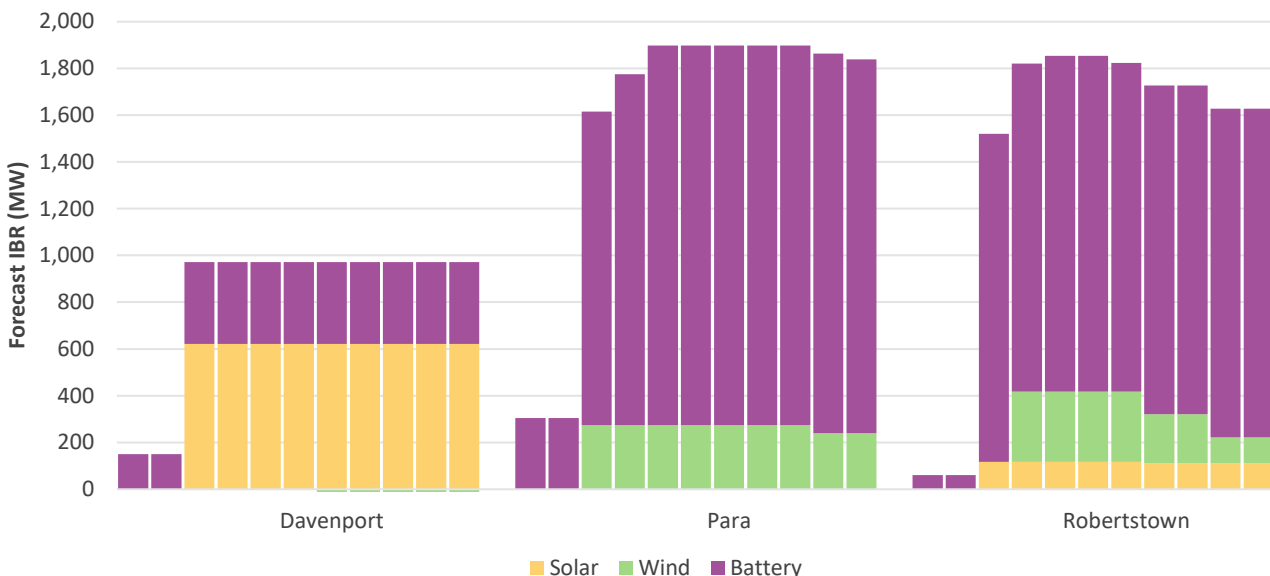
### A2.4.2 System strength requirements

AEMO has confirmed the system strength nodes, and their minimum fault level requirements continue to be maintained at the present values in this 2025 system strength report. AEMO has also updated the IBR projections in South Australia used to determine the efficient level of system strength, based on the latest available preliminary information from the Draft 2026 ISP.

#### A2.4.2.1 Summary of IBR projections for South Australia

AEMO’s 10-year projection of the level and type of IBR and schedule 5.3a plant for South Australian system strength nodes under NER 5.20C.1(c)(2)(ii) is summarised in **Figure 34**. Details for each node are provided in Section A2.4.2.2. As defined in NER S5.1.14(a), **Figure 34** defines the ‘efficient level’ IBR forecast component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028.

**Figure 34** Forecasts of IBR and schedule 5.3a plant for 10 years from 2025-26, South Australia



This IBR forecast is primarily based on the Draft 2026 ISP modelling, which AEMO has allocated to specific nodes based on local network knowledge and engineering judgement. The Draft 2026 ISP is published after this system strength report<sup>37</sup> and projections may slightly differ to the preliminary results which informed this IBR forecast.

AEMO expects that ElectraNet, as the SSSP in South Australia, may engage in joint planning with neighbouring SSSPs to identify any investment efficiencies when assessing the nature of solutions required to meet these requirements. AEMO supports SSSPs considering the latest available information and announcements to adjust this IBR forecast for use in their planning activities between publications of the system strength report, as outlined in Section A2.8.1.1.

#### A2.4.2.2 Nodal IBR projections for South Australia

##### Davenport 275 kV

**Table 53** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 53 Davenport node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Davenport 275 kV	Solar	369	0	0	621	621	621	621	621	621	621	621	621
	Wind	558	0	0	0	0	0	0	0	0	0	0	0
	Battery	10	150	150	350	350	350	350	350	350	350	350	350
	Total IBR	937	150	150	971	971	971	971	905	905	905	905	905

##### Para 275 kV

**Table 54** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 54 Para node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Para 275 kV	Solar	338	0	0	0	0	0	0	0	0	0	0	0
	Wind	360	0	0	274	274	274	274	274	274	274	239	239
	Battery	337	304	304	1,342	1,501	1,624	1,624	1,624	1,624	1,624	1,624	1,599
	Total IBR	1,035	304	304	1,616	1,775	1,898	1,898	1,898	1,898	1,898	1,863	1,838

##### Robertstown 275 kV

**Table 55** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

<sup>37</sup> The Draft 2026 ISP will be published on 10 December 2025 as per the ISP Timetable, at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>.

**Table 55 Robertstown node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Robertstown 275 kV	Solar	22	0	0	117	117	117	117	117	112	112	112	112
	Wind	1,848	0	0	0	300	300	300	300	209	209	110	110
	Battery	599	60	60	1,404	1,404	1,436	1,436	1,406	1,406	1,406	1,406	1,406
	Total IBR	<b>2,469</b>	<b>60</b>	<b>60</b>	<b>1,521</b>	<b>1,821</b>	<b>1,853</b>	<b>1,853</b>	<b>1,823</b>	<b>1,727</b>	<b>1,727</b>	<b>1,628</b>	<b>1,628</b>

### A2.4.2.3 Minimum fault level requirements for South Australia

The South Australian minimum fault level requirements under NER 5.20C.1(c)(2)(i) applicable for planning purposes over the next 10 years are summarised in **Table 56** below. The minimum fault level requirements under NER 5.20C.1(c)(1) applicable for operational purposes over the next one year are in Section A2.9. As defined in NER S5.1.14(a), the values in the table define the minimum fault level component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028. No changes have been made to the minimum fault levels for South Australia in this 2025 system strength report.

**Table 56 Minimum fault level requirements for South Australia**

Node	Pre-contingent (secure) minimum fault level (MVA)	Post-contingent minimum fault level (MVA)	Contingency applicable for post-contingent level	Last changed
Davenport 275 kV	2,400	1,800	One synchronous condenser at Davenport	2020 <i>System Strength Report</i>
Para 275 kV	2,250	2,000	One synchronous condenser at Robertstown	2020 <i>System Strength Report</i>
Robertstown 275 kV	2,550	2,000	One synchronous condenser at Robertstown	2020 <i>System Strength Report</i>

### A2.4.2.1 System strength nodes

No new nodes are under consideration in South Australia at this time.

### A2.4.2.2 Intermittent sub-synchronous oscillations in South Australia

AEMO has observed intermittent oscillations in South Australia and neighbouring parts of South West Victoria in late 2024 and 2025. The root cause of these oscillations is still under ongoing investigation. Investigations to date have not found evidence to suggest that a change in system strength requirements is needed. AEMO will update the system strength requirements in future if needed based on the outcome of further investigations.

### A2.4.2.3 Critical planned outages

SSSPs are expected to consider critical planned outages in their proposed system strength solutions on a case-by-case basis<sup>38</sup>. AEMO has declared several critical planned outages as impactful for maintaining system strength in South Australia, presented in **Table 57**. No changes to the list of critical planned outages in South Australia have been made in 2025.

<sup>38</sup> AEMO, *System Strength Requirements Methodology*, Section 4.5, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/system-strength-requirements-methodology-v21.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/system-strength-requirements-methodology-v21.pdf).

**Table 57 Critical planned outages in South Australia for each system strength node**

Affected node	Network outage	Reason for consideration as a critical outage
All nodes in South Australia	One synchronous condenser (post-Project EnergyConnect, including a Buronga synchronous condenser in New South Wales)	Significant system strength impact in South Australia for another contingency
	One South East to Heywood 275 kV line	
	One South East to Tailem Bend 275 kV line	
	Davenport to Mt Lock 275 kV line	
	Robertstown to Mokota 275 kV line	
	One Robertstown to Tungkillo 275 kV line	
	Robertstown to Canowie 275 kV line	
	Mokota to Willalo 275 kV line	
	Belalie to Willalo 275 kV line	
	Blyth West to Munno Para 275 kV line	

### A2.4.3 NSCAS assessment

AEMO assessed NSCAS needs in South Australia over a five-year outlook period, under a range of demand, generation, and network project assumptions. This section summarises the results of these assessments relating to:

- voltage control and thermal loading (Section A2.4.3.1),
- rapid voltage change (Section A2.4.3.2),
- reactive margin (Section A2.4.3.3),
- system strength, over a three-year period (Section A2.4.3.4),
- inertia, over a three-year period (Section A2.4.3.5), and
- market benefit ancillary services (MBAS, Section A2.4.3.6).

**Table 58** provides an overview of the core scenarios studied for South Australia. Chapter A2.8 provides further detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2024 NSCAS assessment.

**Table 58 South Australia NSCAS scenarios and outcomes**

Case	Scenario assumptions	Year of assessment	NSCAS gap
Low demand (day)	Committed Projects Only, zero, one and two units in service scenarios considered.	2025-26	Existing voltage RSAS gap for low demand
	Committed Projects Only zero, one and two units in service scenarios considered.	2030-31	Monitored risk
Low demand (night)	Committed Projects Only zero, one and two units in service scenarios considered.	2025-26	Existing voltage RSAS gap for low demand
	Committed Projects Only zero, one and two units in service scenarios considered.	2030-31	Monitored risk
High demand	Committed Projects Only	2025-26	No gap identified
	Committed Projects Only	2030-31	Emerging risk driven by load growth projected in Northern South Australia
System strength	Modified ESOO scenario <sup>A</sup> ,	2025-26 to 2029-30	No gap identified

Case	Scenario assumptions	Year of assessment	NSCAS gap
<b>System strength</b>	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	No gap identified
<b>Inertia</b>	Modified ESOO scenario <sup>A</sup> ,	2025-26 to 2029-30	No gap identified
<b>Inertia</b>	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	No gap identified

A. Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station closure notification (see <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>).

### A2.4.3.1 Voltage control and thermal loading

AEMO has assessed expected voltage control and thermal loading issues in South Australia over a five-year outlook period, under both low and high demand scenarios. Additionally, AEMO conducted this analysis across a broad range of scenarios with reactive plant considered out of service and minimum unit combinations. The analysis considered a range of region-specific network sensitivities and operating conditions to provide full coverage of heightened risk periods in South Australia under both minimum daytime, minimum nighttime and maximum demand.

#### Voltage control challenges remain in South Australia – previously declared NSCAS gap

In December 2023, AEMO declared an NSCAS gap for voltage control in South Australia, representing an immediate need for up to 200 MVAR in the Adelaide metropolitan area. Following this declaration, ElectraNet provided advice on its planned remediation through a RIT-T process for procurement of additional shunt reactors located at Adelaide Metropolitan region (3 x 60 MVAR plus 2 x 50 MVAR ) and South East (1 x 50 MVAR). The installation of two reactors in Adelaide Metropolitan region (2 x 50 MVAR) and one (1 x 50 MVAR) in the South East is now complete with the remaining three expected to be in service in October 2027.

AEMO identified voltage control improvement with the installation of the new reactors under low demand conditions during night and day demand conditions. AEMO considers that the gap remains, as managing sufficient SVC headroom and network voltages within limits remains a challenge. This is further exacerbated under system typical scenarios featuring a single reactor, SVC or synchronous condenser out of service. AEMO expects this gap to be closed upon installation of the remaining reactors scheduled for Oct 2027.

#### Voltage control challenges in South Australia with leading power factor

AEMO and ElectraNet introduced new conditions where South Australia could operate down to a single synchronous unit as part of its limits advice update in September 2025<sup>39</sup>. During night-time conditions there exists a risk of growing capacitive demand exacerbating voltage control issues and managing sufficient MVAR headroom of SVCs. AEMO’s 2030-31 minimum night demand studies indicate there is no voltage management risk in this scenario under current assumptions of committed BESS, VAR dispatch scheme and reactive demand trends. While completion of the roll-out of reactors under the current RIT-T and committed BESS will provide significant relief to this issue, AEMO notes this as an emerging risk and will continue to work with ElectraNet and SA Power Networks to track trends in reactive demand over time.

<sup>39</sup> AEMO, September 2025, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?rev=b42ff9893d2b47788d65404d045124f0&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?rev=b42ff9893d2b47788d65404d045124f0&sc_lang=en).

## Emerging risk in supplying projected demand growth in South Australia

AEMO has identified thermal overloads and voltage control risks in northern and central parts of South Australia predominantly driven by projected load growth. Projected load growth in the Eyre Peninsula region and metropolitan areas is making it difficult to provide voltage control with plant limits. This is further exacerbated when nearby shunts, SVCs and synchronous condensers are out of service.

AEMO considers this risk as a candidate for NSCAS, as the localised load growth is projected to drive voltage management issues where additional supply would only resolve this in specific locations. ElectraNet’s 2025 TAPR<sup>40</sup> identified several key transmission projects intended to accommodate this load growth, including the Eyre Peninsula upgrade which is progressing through a RIT-T. While the proposed contingent project is expected to address voltage and thermal limitations, this would depend on the scale of load growth and committed load applications themselves. AEMO will continue to work with ElectraNet to monitor network needs as they approach.

### A2.4.3.2 Rapid voltage change

AEMO assessed the expected voltage change impacts of switching reactive plant in South Australia. **Table 59** summarises the results of this analysis indicating maximum voltage deviations for a given case, the appropriate IEC Standard<sup>41</sup>, and whether that standard is met. The results demonstrate that the standard is met for all conditions assessed.

Table 59 **Rapid voltage change results for reactive plant switching in South Australia**

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Minimum demand day	Committed Projects Only	2025-26	1.12%	Bundey 330 kV	60 MVAR reactor at Bundey 330 kV Bus	3-5%	Yes
	Committed Projects Only	2030-31	1.01%	Temple West 275 kV	50 MVAR reactor at Temple West 275 kV Bus		Yes
Minimum demand night	Committed Projects Only	2025-26	1.19%	Bundey 330 kV	60 MVAR reactor at Bundey 330 kV Bus		Yes
	Committed Projects Only	2030-31	1.04%	Bundey 330 kV	60 MVAR reactor at Bundey 330 kV Bus		Yes
Maximum demand	Committed Projects Only	2025-26	4.12%	Bundey 330 kV	60 MVAR reactor at Bundey 330 kV Bus		Yes
	Committed Projects Only	2030-31	1.95%	Black Rock 275 kV	100 MVAR capacitor at Taillem Bend 275 kV Bus		Yes

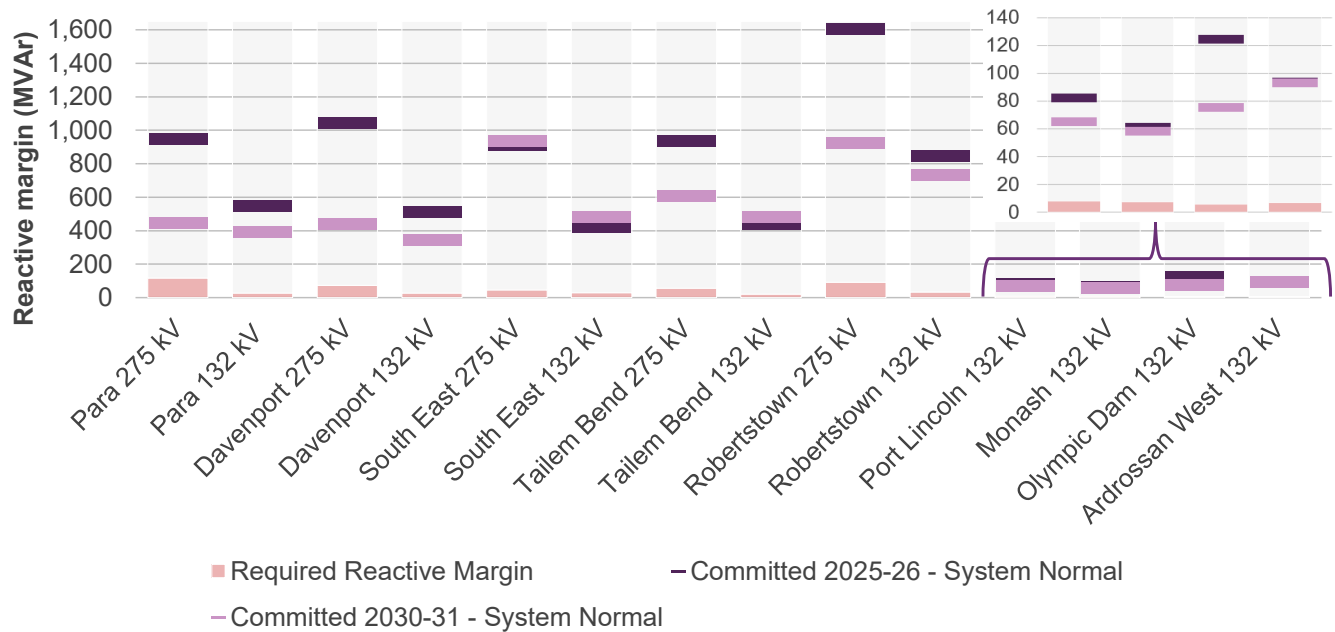
<sup>40</sup> Electranet, 2025, see [https://electranet.com.au/wp-content/uploads/2025/06/250516\\_TAPR\\_FINAL-1.pdf](https://electranet.com.au/wp-content/uploads/2025/06/250516_TAPR_FINAL-1.pdf).

<sup>41</sup> Requirements for voltage fluctuation are defined by NER S5.1a.5 and TR IEC 61000.3.7, Table 6, Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed four within a 24-hour period, with each change allowing a permissible variation of 3-5% for network elements operated at greater than 230 kV and 5-6% for network elements operated at voltages between 35 kV and 230 kV.

### A2.4.3.3 Reactive margin

AEMO assessed whether the system normal reactive margins at critical buses in South Australia are expected to remain above the system standard<sup>42</sup> of 1% of the local maximum fault level over the five-year outlook period. **Figure 35** summarises the results and indicates that all reactive margins are projected to meet the standard.

**Figure 35 Minimum reactive margin (MVA<sub>r</sub>) observed for critical buses in South Australia**



### A2.4.3.4 System strength

AEMO modelled projected fault levels under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>43</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in Section A2.8.2.

The expected three phase fault current at each system strength node in South Australia was compared against the latest minimum fault current requirements published in Section A2.4.2. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year<sup>44</sup>.

The results of this assessment are summarised in **Table 60**, and confirm there are no system strength gaps in South Australia.

<sup>42</sup> Required reactive margin is defined by NER S5.1.8 as “not less than 1% of the maximum fault level (in MVA) at the connection point”. For the purposes of this assessment, the required reactive margin was calculated based on the 2025-26 maximum fault level.

<sup>43</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

<sup>44</sup> 99.87% is equivalent to three standard deviations above the mean. See [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc_lang=en).

**Table 60 South Australia fault level requirements and identified deficits against the requirements**

System strength node	Fault level requirement (MVA)	Identified deficit in the Modified ESOO scenario (MVA)					Identified deficit in the Modified ESOO scenario with modelled parts of the RIT-T solutions (MVA)				
		2025-26	2026-27	2027-28	2028-29	2029-30	2025-26	2026-27	2027-28	2028-29	2029-30
Davenport 275 kV	2,400	0	0	0	0	0	0	0	0	0	0
Para 275 kV	2,250	0	0	0	0	0	0	0	0	0	0
Robertstown 275 kV	2,550	0	0	0	0	0	0	0	0	0	0

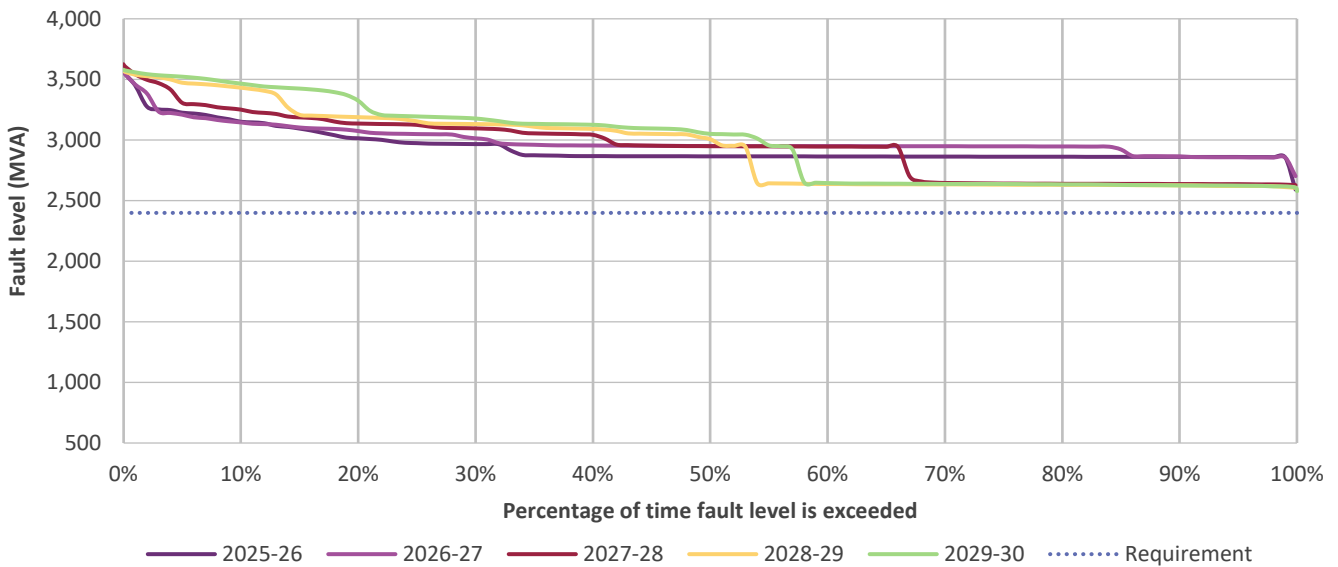
Section A2.4.2 provides additional detail on the calculation of fault level requirements. Detailed projected fault levels per system strength node are shown below, with and without modelled parts of the RIT-T solutions. ElectraNet’s *System Strength Requirements in South Australia – Project Assessment Draft Report (PADR)*<sup>45</sup> found that additional system strength investments were not required to meet South Australia’s system strength requirements. The projected fault levels with and without modelled parts of the RIT-T solutions for South Australia differ only due to interstate contributions from neighbouring regions.

### Davenport 275 kV

**Figure 36** shows the projected three phase fault level at the Davenport 275 kV node without the modelled parts of the RIT-T solution. Davenport does not show any deficits in the modelling horizon. **Figure 37** shows no notable differences in the projected fault levels after implementing the modelled parts of the RIT-T solutions.

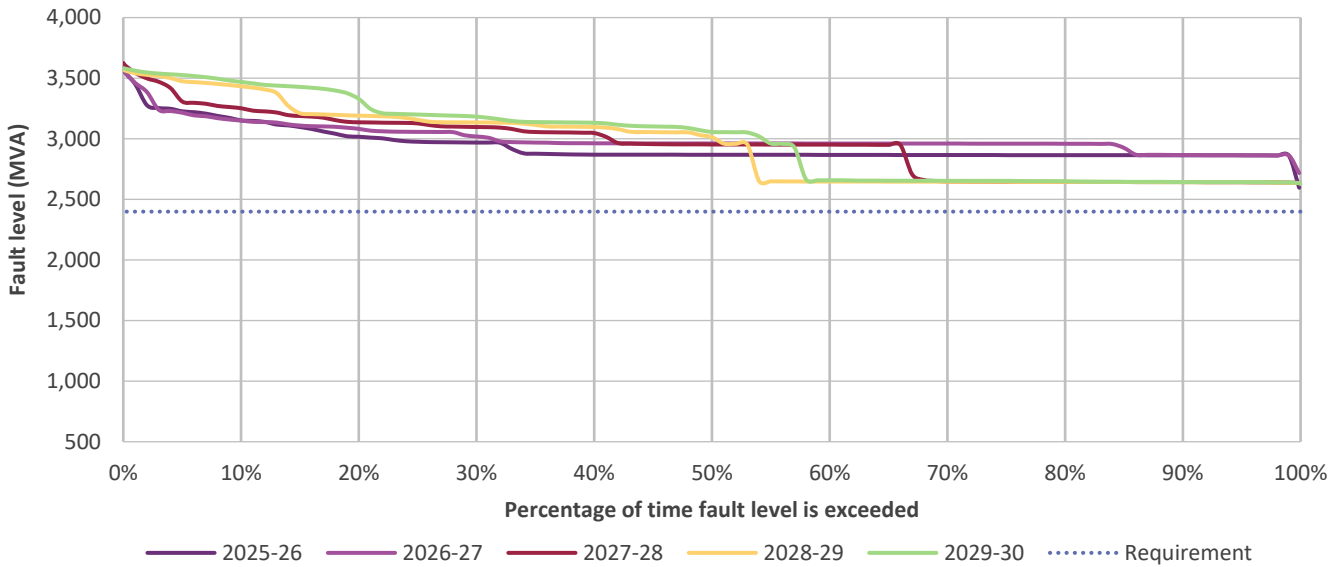
The summarised results for the 99.87<sup>th</sup> percentile values from these figures are in **Table 61**. Fault level requirements are projected to be met at Davenport with existing system strength services.

**Figure 36 Davenport node fault level duration curves and minimum requirement**



<sup>45</sup> At [https://electranet.com.au/wp-content/uploads/2025/04/RIT-T-PADR\\_Meeting-System-Strength-in-SA.pdf](https://electranet.com.au/wp-content/uploads/2025/04/RIT-T-PADR_Meeting-System-Strength-in-SA.pdf).

**Figure 37 Davenport node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 61 Davenport node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Davenport 275 kV	Minimum fault level requirement (MVA)	2,400	2,400	2,400	2,400	2,400
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	2,592	2,702	2,628	2,605	2,609
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	2,595	2,718	2,636	2,633	2,635
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

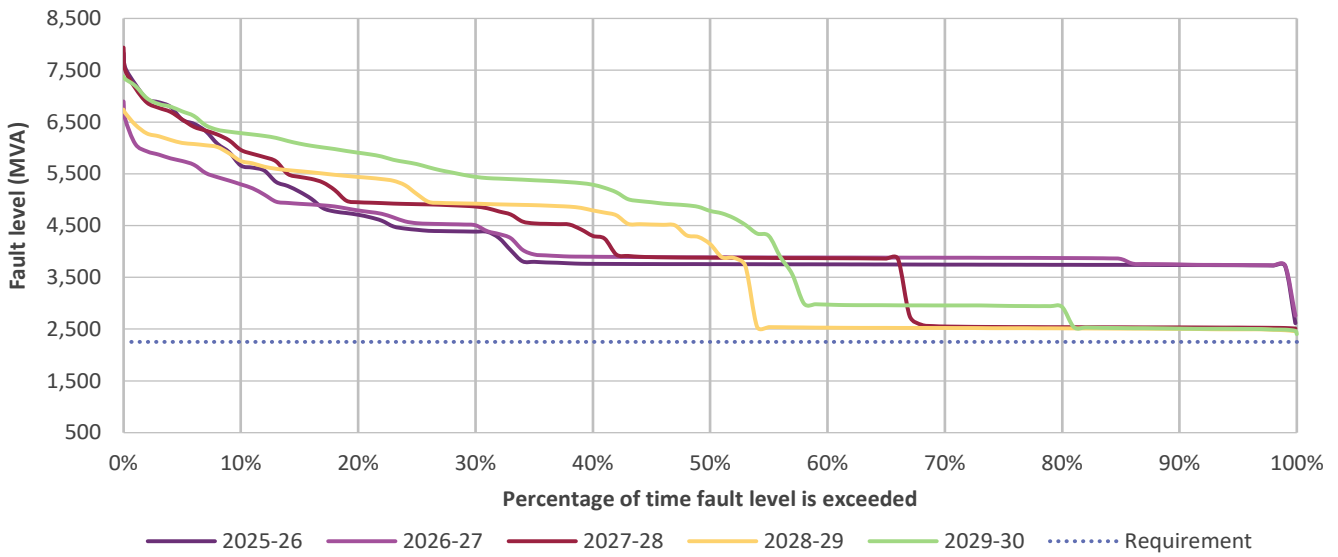
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Para 275 kV

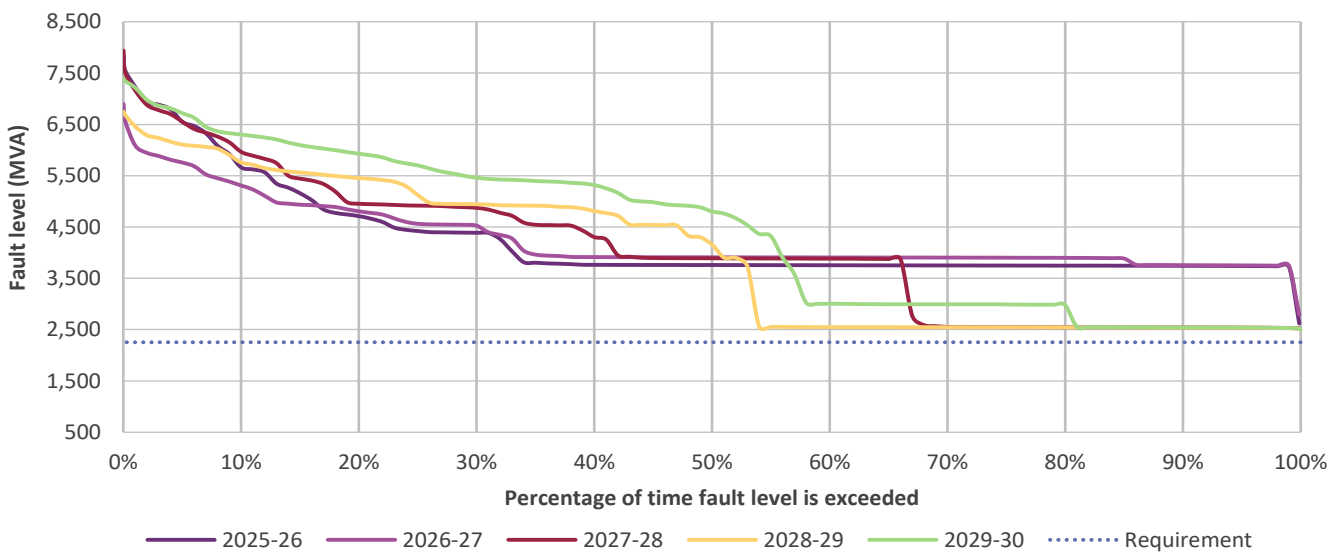
Figure 38 shows the projected three phase fault level at the Para 275 kV node without the modelled parts of the RIT-T solution. Para does not show any deficits in the modelling horizon. Figure 39 shows no notable differences in the projected fault levels after implementing the modelled parts of the RIT-T solutions.

The summarised results for the 99.87<sup>th</sup> percentile values from these figures are in Table 62. Fault level requirements are projected to be met at Para with existing system strength services.

**Figure 38 Para node fault level duration curves and minimum requirement**



**Figure 39 Para node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 62 Para node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Para 275 kV	Minimum fault level requirement (MVA)	2,250	2,250	2,250	2,250	2,250
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	2,613	2,758	2,512	2,461	2,467
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	2,619	2,784	2,525	2,518	2,521
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS Gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

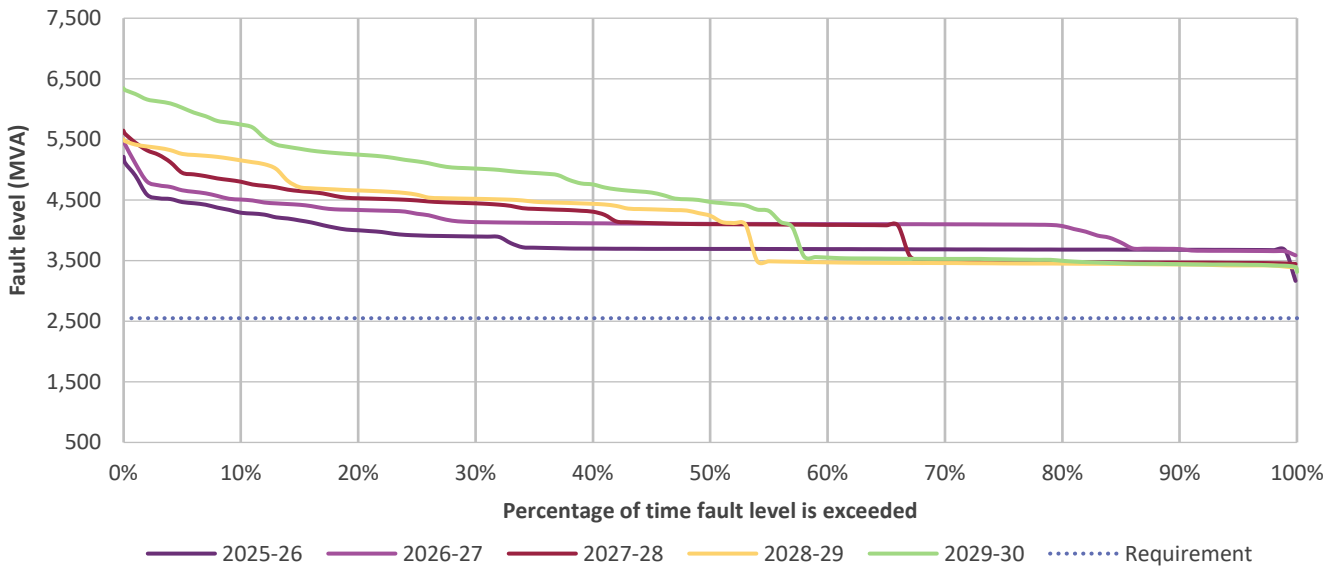


### Robertstown 275 kV

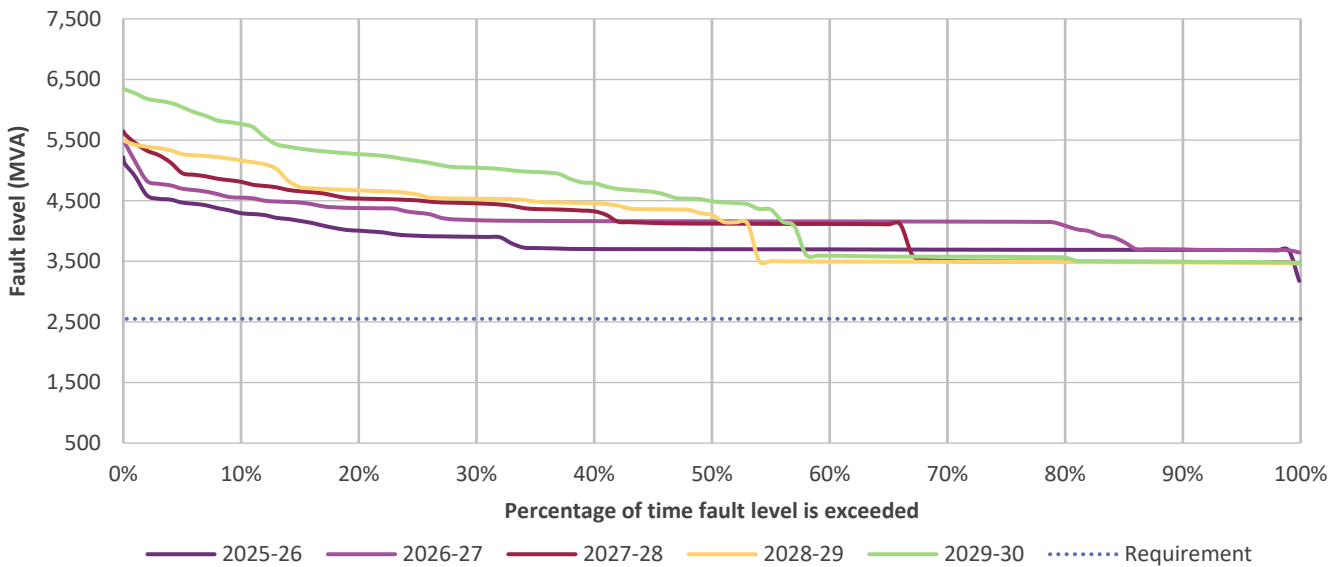
Figure 40 shows the projected three phase fault level at the Robertstown 275 kV node without the modelled parts of the RIT-T solution. Robertstown does not show any deficits in the modelling horizon. Figure 41 shows no notable differences in the projected fault levels after implementing the modelled parts of the RIT-T solutions.

The summarised results for the 99.87th percentile values from these figures can be found in Table 63. Fault level requirements are projected to be met at Robertstown with existing system strength services.

**Figure 40 Robertstown node fault level duration curves and minimum requirement**



**Figure 41 Robertstown node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 63 Robertstown node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Robertstown 275 kV</b>	Minimum fault level requirement (MVA)	2,550	2,550	2,550	2,550	2,550
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	3,168	3,586	3,446	3,385	3,395
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	3,174	3,645	3,469	3,461	3,470
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS Gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### A2.4.3.5 Inertia

AEMO modelled projected inertia under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>46</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in section A2.8.2.

AEMO assessed the expected levels of available inertia in South Australia against the latest inertia requirements published in section A2.4.1. The assessment considered the South Australia portion of the *system-wide inertia level*, the islanded regional requirements, and the likelihood of the region becoming islanded. Section A2.4.1 provides further detail on the calculation and application of these inertia requirements.

AEMO’s assessment of the resulting inertia needs, summarised in **Table 64**, indicates sufficient inertia is available to meet the *inertia requirements* in South Australia. ElectraNet is also required to ensure sufficient supplies are available to meet its *inertia sub-network allocation* from 2 December 2027.

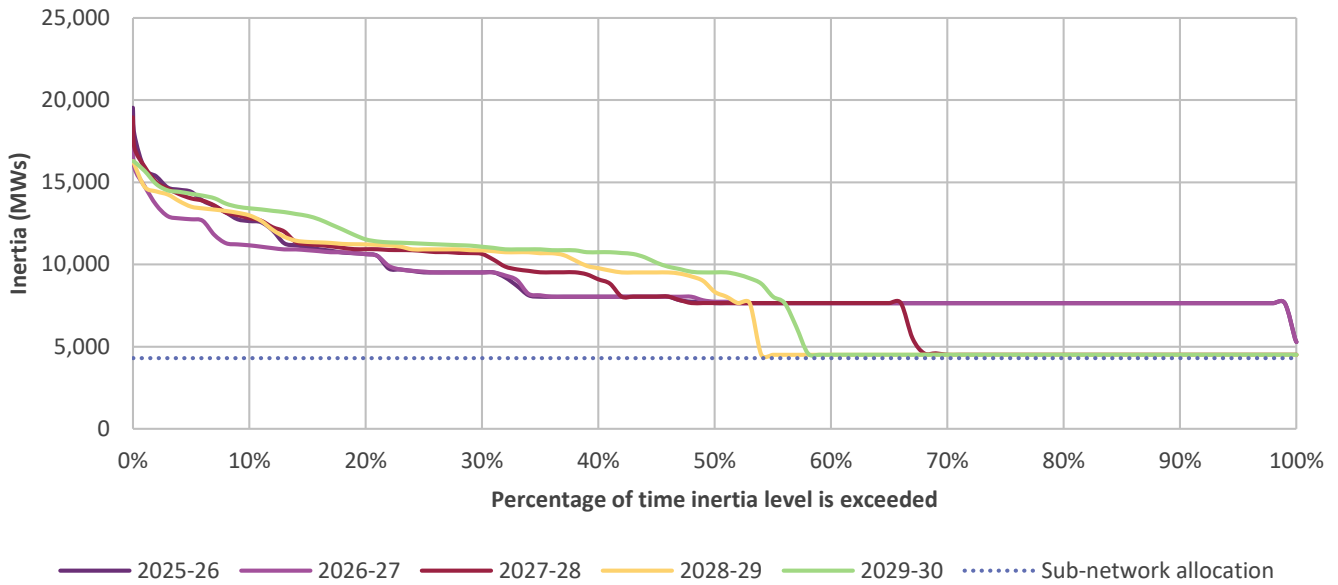
AEMO has deemed South Australia as sufficiently likely to island on its own until the commissioning of Project EnergyConnect Stage 2 and associated control schemes are in place. On this basis, AEMO has assessed the region against both its *inertia sub-network allocation* and its individual (islanded) *secure level of inertia*.

### System-wide inertia level assessment for South Australia

**Figure 42** and **Table 64** present the projected levels of inertia expected to be available in South Australia over the next five years. This indicates that levels are expected to remain above the *inertia sub-network allocation*.

<sup>46</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

**Figure 42** Projected inertia for the five-year outlook, modified ESOO scenario, South Australia



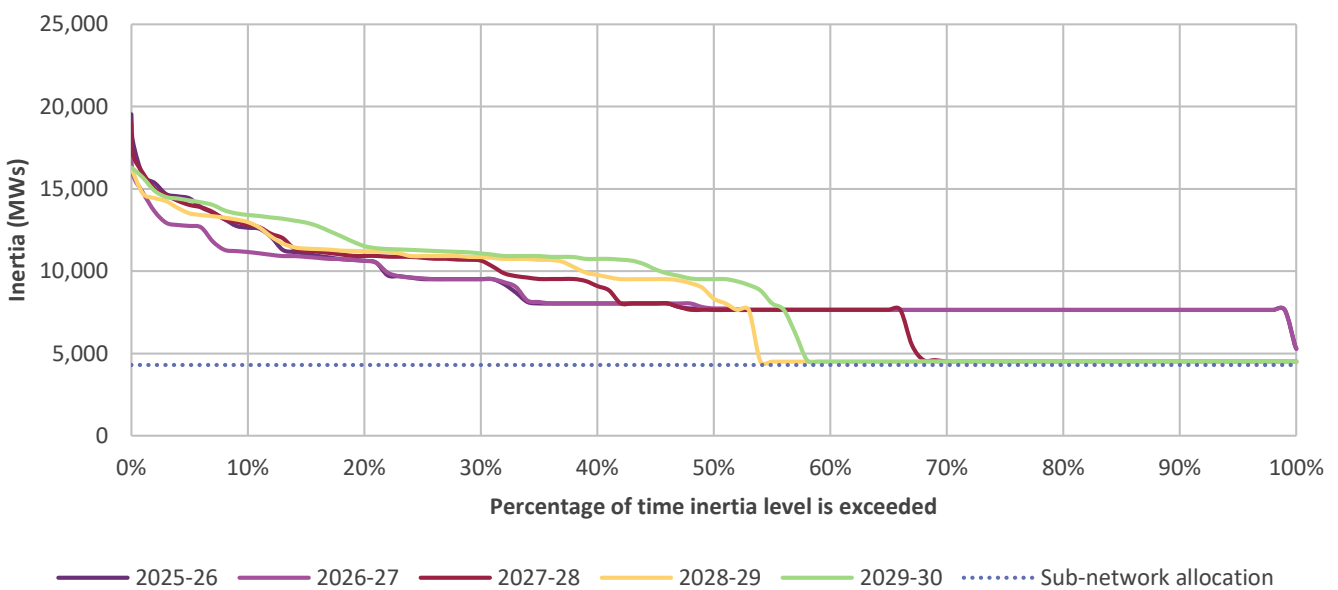
**Table 64** Inertia sub-network allocation and projections, modified ESOO scenario, South Australia

	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Inertia sub-network allocation (MWs)</b>	4,300	4,300	4,300	4,300	4,300
<b>Available inertia 99.87% of the time (MWs)</b>	5,510	5,510	4,503	4,503	4,503
<b>Inertia deficit (MWs)</b>	0	0	0	0	0
<b>NSCAS gap (Yes/No)*</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.

\*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

**Figure 43** Projected inertia for the five-year outlook, Modified ESOO scenario with the modelled parts of the RIT-T solution, South Australia



**Table 65 Inertia sub-network allocation and projections, Modified ESOO scenario with modelled parts of the RIT-T solution, South Australia**

	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Inertia sub-network allocation (MWs)</b>	4,300	4,300	4,300	4,300	4,300
<b>Available inertia 99.87% of the time (MWs)</b>	5,510	5,510	4,503	4,503	4,503
<b>Inertia deficit (MWs)</b>	0	0	0	0	0
<b>NSCAS gap (Yes/No)*</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.  
 \* NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

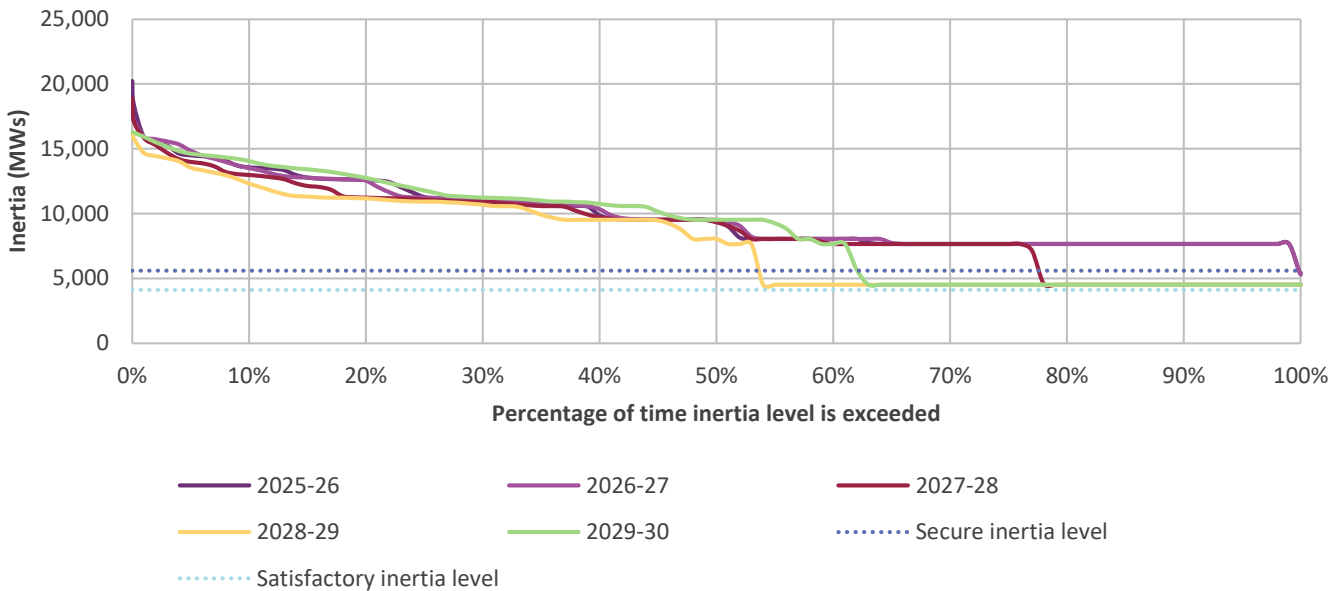
### Islanded inertia assessment for South Australia

Figure 44 and Table 66 show the projected inertia levels expected to be available under islanded operation, or credible risk of islanding, of the South Australia region in the modified ESOO scenario. Under typical operation, available inertia is expected to fall below the secure inertia level for islanded operation across all projected financial years.

The projections did not consider the availability of GFM inverters like Hornsdale or Dalrymple battery, which can provide synthetic inertia. AEMO has estimated inertia constants for South Australian GFM batteries in accordance with the Inertia Network Services Specification testing methodology<sup>47</sup> and found that available synthetic inertia is expected to address the remaining deficits.

Following the commissioning of Project EnergyConnect Stage 2 in 2027-28, South Australia will transition from a region likely to island to unlikely, due to the additional interconnection with New South Wales and Victoria. As a result, assessing against the islanded requirement will no longer be necessary.

**Figure 44 Projected inertia for the five-year outlook, Modified ESOO scenario, South Australia islanded case**



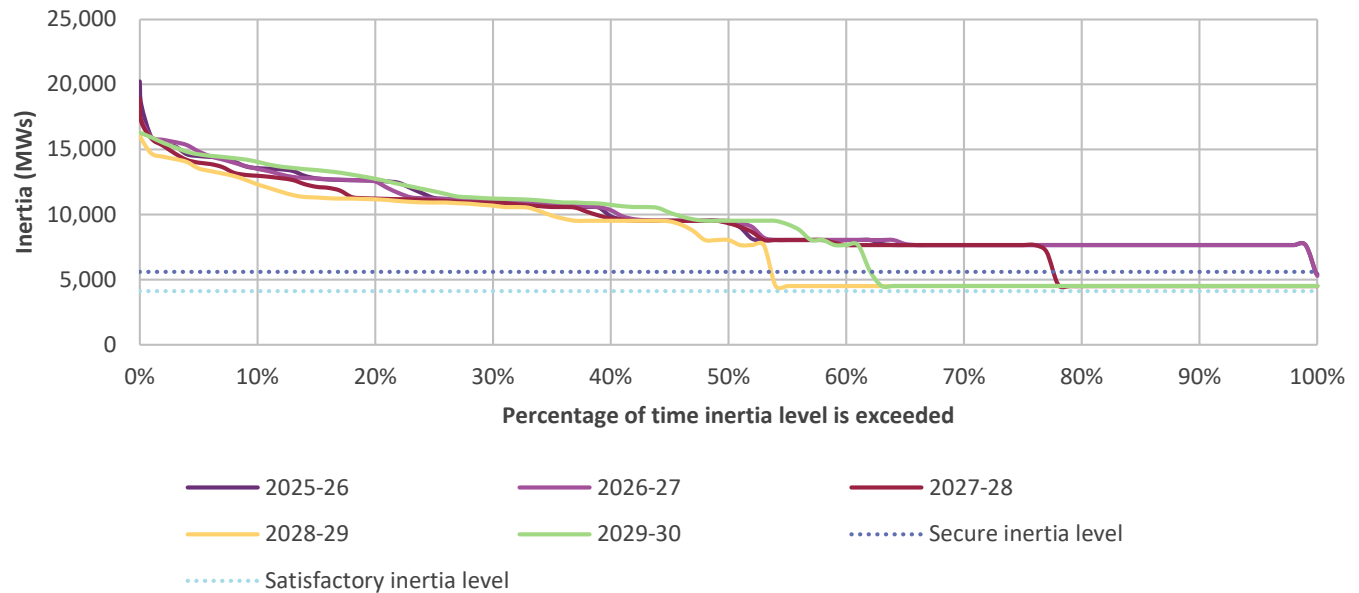
<sup>47</sup> AEMO, *Inertia Requirements Methodology*, 2024, Appendix A, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/inertia-requirements-methodology-v2-0.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.pdf).

**Table 66 Secure inertia level and projections, Modified ESOO scenario, South Australia islanded case**

	2025-26	2026-27	2027-28	2028-29	2029-30
Assumed level of 1-second FCAS (MW)	403	403	403	403	403
Secure inertia level (MWs)	5,600	5,600	5,600	5,600	5,600
Available inertia 99.87% of the time (MWs)	5,510	5,510	4,503	4,503	4,503
Inertia deficit (MWs)	90	90	1,097	1,097	1,097
NSCAS gap (Yes/No)*	No	No	No	No	No

Notes: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of Project EnergyConnect Stage 2 and necessary protection schemes are in place to manage the non-credible loss of Project EnergyConnect and the Heywood interconnector. \* NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

**Figure 45 Projected inertia for the five-year outlook, Modified ESOO scenario with modelled parts of the RIT-T solution, South Australia islanded case**



**Table 67 Secure inertia level and projections, Modified ESOO scenario with modelled parts of the RIT-T solution, South Australia islanded case**

	2025-26	2026-27	2027-28	2028-29	2029-30
Assumed level of 1-second FCAS (MW)	403	403	403	403	403
Secure inertia level (MWs)	5,600	5,600	5,600	5,600	5,600
Available inertia 99.87% of the time (MWs)	5,510	5,510	4,503	4,503	4,503
Inertia deficit (MWs) <sup>A</sup>	90 <sup>A</sup>	90 <sup>A</sup>	1,097	1,097	1,097
NSCAS Gap (Yes/No) <sup>B</sup>	No	No	No	No	No

Notes: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of Project EnergyConnect Stage 2 and necessary protection schemes are in place to manage the non-credible loss of Project EnergyConnect and the Heywood interconnector. A. Contribution from GFM inverters and contracted plant for system strength addresses these deficits B. NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

### A2.4.3.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in South Australia. **Table 68** provides a comparison of binding hours and marginal values for the top impact constraints in South Australia<sup>48</sup>. All constraints with a marginal value exceeding \$60,000 per year have previously been considered by ElectraNet. In each case, a risk status, project, control scheme, or other mitigation strategy has been identified. These options are being monitored through the ElectraNet annual TAPR process and may trigger action if market benefits exceed remediation costs.

**Table 68 South Australia high-impact constraint summary for 2024 calendar year**

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
S>NIL_MHNW1_MHNW2	Out= Nil, avoid O/L Monash-North West Bend #2 132kV on trip of Monash-North West Bend #1 132kV line, Feedback.	10.9M (↑\$2.8M)	1,673.4	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. This constraint will be alleviated when project Increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bidirectionality and allows it to run forward if required.
S>NIL_HUWT_STBG3	Out = Nil; Limit Snowtown WF generation to avoid Snowtown - Bungama line OL on loss of Hummocks - Waterloo line. [Note: Constraint Swamped when Wattle PT when generating >=60 MW)	3.2M (↓\$0M)	316.3	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. ElectraNet is monitoring this constraint to determine if the implementation of the proposed 10-band rating NCIPAP project is likely to alleviate this constraint.
S>NIL_BWMP_HUWT	Out= Nil, avoid O/L Hummocks - Waterloo 132kV on trip of Blyth West- Munno Para 275kV line, Feedback	1.6M (↑\$1.5M)	144.6	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. ElectraNet is monitoring this constraint to determine if the implementation of our proposed 10-band rating NCIPAP project is likely to alleviate this constraint, or if options such as automatic runback control schemes for 132 kV wind farms in the Mid North could be needed to alleviate this constraint.
S-NIL_WTPT_SC+INV_2	Out=NIL, limit output of Wattle Pt WF based on Wattle Pt statcom status & the number of Dalrymple battery inverters I/S (Note: constraint is swamped when the number of Dalrymple battery inverters is >= 10)	1.3M (↑\$1.3M)	115.3	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. This constraint is applied to manage system security during STATCOM unavailability at Wattle Point Wind Farm.
S>NIL_NWRB2_NWRB1	Out= NIL, avoid O/L North West Bend-Robertstown #1 132kV line on trip of North West Bend-Robertstown #2 132kV line (this trips MWP1-3 SFs), Feedback	1.1M (↓\$1.6M)	157.8	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. A project to increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bidirectionality and allow it to run forward if required. This project should allvate this constraint
S>>NIL_TWPA_TPRS	Out= NIL, avoid O/L Templers-Roseworthy 132kV line on trip of Templers West-Para 275kV line, Feedback	0.5M (↑\$0.1M)	62.2	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. This constraint would be alleviated by the installation of a second 275/132 kV transformer at Templers West and reconfiguration of the Mid North 132 kV system as part of the Northern Transmission Project.

<sup>48</sup> Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is in the NSCAS Description and Quantity Procedure, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0).

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
S>>NIL_RBTX_RBTX_1	Out= Nil, avoid O/L of one Robertstown 275/132kV TX on trip of other Robertstown 275/132kV TX, Feedback	0.2M (↑\$0.2M)	60.4	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. A project to increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bidirectionality and allow it to run forward if required. This project should allivate this constraint
SVML^NIL_MH-CAP_ON	Out=NIL, SA to Vic on ML upper transfer limit to manage voltage collapse at Monash (Note: applies when capacitor banks at Monash are available and I/S for switching.)	0.2M (↓\$0.4M)	293.7	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. A project to increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bidirectionality and allow it to run forward if required. This project should allivate this constraint
S>>NIL_TBTX4_TBMO_1	Out= Nil, avoid O/L Tailem Bend to Mobilong #1 132kV line on trip of Tailem Bend 275/132kV (#4) transformer, Feedback	0.2M (↑\$0.2M)	27.4	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. ElectraNet is investigating whether project South East Expansion or the installation of a second 275/132 kV transformer at Tailem Bend alleviates this constraint.
S>>NIL_TBTU_TBTU_1	Out= NIL, avoid O/L Tailem Bend-Tungkillo 275kV line 1 or 2 on trip of parallel Tailem Bend-Tungkillo 275 kV line 2 or 1, Feedback	0.1M (↑\$0.1M)	29.0	ENET 2025 TAPR Table 7: South Australia's top 20 binding constraints in 2024. Electranet has described a South East Expansion project which will alleviate this constraint.

Note: From annual NEM Constraint Report, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams>. Constraints have been prioritised as per calendar year 2024 data

## A2.5 Tasmania

- AEMO has not identified any thermal or voltage gaps in Tasmania over the five-year period. Future power system changes, including connection of new large loads, could impact voltage control and reactive margins in some locations. AEMO will continue to monitor these risks.
- AEMO has identified system strength deficits across Tasmania, but TasNetworks has work underway to continue a contracting arrangement which addresses these deficits. Additionally, the minimum secure fault level requirement is due to decrease to 750 MVA following the completion of a STATCOM installation in 2026.
- AEMO has identified inertia deficits of between 2,463 MWs and 2,822 MWs, but TasNetworks has work underway to continue a contracting arrangement which addresses these deficits.

This section covers:

- inertia requirements, including the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level over a 10-year horizon,
- system strength requirements, comprising the identification of system strength nodes, minimum fault level requirements over a 10-year horizon, and the 10-year forecast of IBR used to determine the efficient level of system strength, and
- NSCAS assessment details, including considerations for both inertia and system strength projections against the requirements.

### A2.5.1 Inertia requirements

AEMO has confirmed that the inertia requirements for Tasmania remain unchanged this year. **Table 69** provides a summary of the *inertia requirements* for Tasmania, including the satisfactory and secure levels of inertia when planning for islanded operation. Tasmania is not subject to the system-wide inertia requirement, so no sub-network allocation is applicable.

**Table 69** Tasmania inertia requirements from 2 December 2025 to 1 December 2035

Quantity	Value
Satisfactory inertia level	3,200 MWs
Secure inertia level	3,800 MWs
Likelihood of islanding	Likely (continuous)

#### A2.5.1.1 Likelihood of islanding

**Table 70** shows an assessment of the likelihood of Tasmania islanding.

**Table 70 Assessment of the likelihood of Tasmania islanding**

Criterion	Tasmania
<b>Inertia levels compared to secure inertia level</b>	Inertia levels forecast to be below the secure inertia level after existing system strength contracts expire on 1 December 2025.
<b>Inertia sub-network allocation</b>	Not applicable.
<b>Existing interconnections</b>	One DC link to Victoria.
<b>Future interconnections and status</b>	Project Marinus: Two DC links to Victoria (Stage 1 and Stage 2).
<b>History of islanding</b>	No AC interconnection to mainland regions.
<b>Applicable control schemes</b>	Frequency Control System Protection Scheme (FCSPS).
<b>Likelihood of islanding after contingency event</b>	Tasmania always islanded from an electrical AC perspective.

### A2.5.1.2 Co-optimisation with contracted fast frequency response (FFR) and 1-Second FCAS

The amount of FFR available in the NEM has increased rapidly in the last half a decade due to significant battery connections. The 1-Second FCAS market was introduced as a mechanism for procuring FFR to meet the FOS.

The role of the inertia requirements is to slow down the change in frequency which occurs after a generation or load contingency until FCAS responds to contain and restore frequency. Following the staged introduction of 1-Second FCAS from 2023, less inertia has been required because FCAS now responds faster.

The NEM is now reaching a point where additional FFR may no longer allow the inertia requirements to decrease. In every region, the limiting factor in meeting the FOS under current levels of FFR is no longer the nadir but rather RoCoF over the first 300-500 ms. FFR is very effective at limiting the frequency nadir, but inertia is the most appropriate tool for limiting RoCoF over the first 300-500ms.

In previous inertia reports, FFR curves have been used as a tool to determine the trade-off between inertia and FFR. Continued work studying this phenomenon in PSS<sup>®</sup>E shows these curves are unlikely to extrapolate to the levels of FFR currently available in the NEM. AEMO intends to consider the impact of additional FFR on the inertia requirements on a case-by-case basis.

BESS are still able to contribute significantly to meeting the inertia requirements by providing synthetic inertia which is similarly as effective as synchronous inertia in limiting RoCoF.

### A2.5.2 System strength requirement

AEMO has confirmed the system strength nodes, and their minimum fault level requirements continue to be maintained at the present values in this 2025 system strength report. AEMO has also updated the IBR projections in Tasmania used to determine the efficient level of system strength, based on the latest available preliminary information from the Draft 2026 ISP.

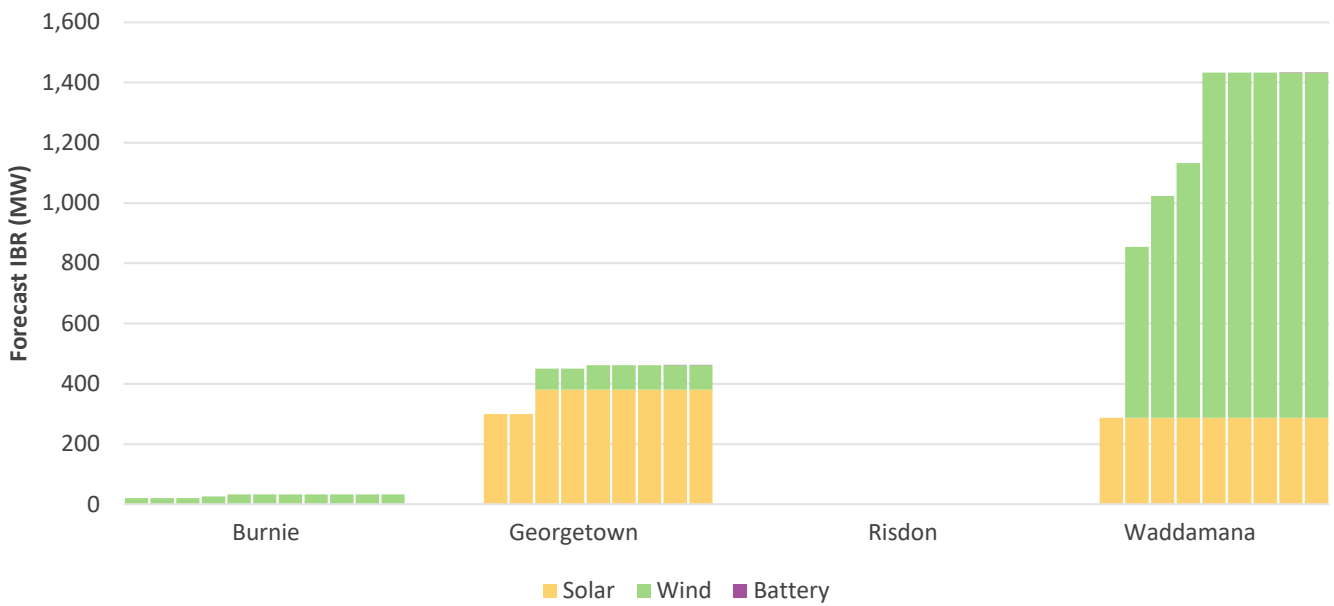
#### A2.5.2.1 Summary of IBR projections for Tasmania

AEMO's 10-year projection of the level and type of IBR and schedule 5.3a plant for Tasmanian system strength nodes under NER 5.20C.1(c)(2)(ii) is summarised in **Figure 46**. Details for each node are in Section A2.5.2.2. As defined in NER S5.1.14(a), **Figure 46** defines the 'efficient level' IBR forecast component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028.

This IBR forecast is primarily based on the Draft 2026 ISP modelling, which AEMO has allocated to specific nodes based on local network knowledge and engineering judgement. The Draft 2026 ISP is published after this system strength report<sup>49</sup> and projections may slightly differ to the preliminary results which informed this IBR forecast.

AEMO expects that TasNetworks, as the SSSP in Tasmania, may engage in joint planning with neighbouring SSSPs to identify any investment efficiencies when assessing the nature of solutions required to meet these requirements. AEMO supports SSSPs considering the latest available information and announcements to adjust this IBR forecast for use in their planning activities between publications of the system strength report, as outlined in Section A2.8.1.1.

**Figure 46 Forecasts of IBR and schedule 5.3a plant for 10 years from 2025-26, Tasmania**



### A2.5.2.2 Nodal IBR projections for Tasmania

#### Burnie 110 kV

**Table 71** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 71 Burnie node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Burnie 110 kV	Solar	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	251	21	21	21	26	33	33	33	33	33	33	33
	Battery	0	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	251	21	21	21	26	33	33	33	33	33	33	33

<sup>49</sup> The Draft 2026 ISP will be published on 10 December 2025 as per the ISP Timetable, at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>.

### George Town 220 kV

Table 72 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 72 George Town utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
George Town 220 kV	Solar	0	0	0	300	300	380	380	380	380	380	380	380
	Wind	168	0	0	0	0	70	70	82	82	82	82	82
	Battery	0	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	168	0	0	300	300	450	450	462	462	462	462	462

### Risdon 110 kV

Table 73 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 73 Risdon utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Risdon 110 kV	Solar	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	0	0	0	0	0
	Battery	0	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	0	0	0	0	0	0	0	0	0	0	0	0

### Waddamana 220 kV

Table 74 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 74 Waddamana utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Waddamana 220 kV	Solar	0	0	0	287	287	287	287	287	287	287	287	287
	Wind	148	0	0	0	568	737	846	1,146	1,146	1,146	1,146	1,146
	Battery	0	0	0	0	0	0	0	0	0	0	0	0
	Total IBR	148	0	0	287	855	1,024	1,133	1,433	1,433	1,433	1,433	1,433

### A2.5.2.3 Minimum fault level requirements for Tasmania

The Tasmanian minimum fault level requirements under NER 5.20C.1(c)(2)(i) applicable for planning purposes over the next 10 years are summarised in **Table 75** below. The minimum fault level requirements under NER 5.20C.1(c)(1) applicable for operational purposes over the next year are in Section A2.9. As defined in NER S5.1.14(a), the values in the table define the minimum fault level component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028.

In this 2025 system strength report the minimum pre-contingent fault level at Burnie has been increased from 750 MVA to 850 MVA in 2026 only, to reflect delays to commissioning of a statcom at Port Latta which will allow the minimum fault level to be reduced to 750 MVA. No changes have been made for other Tasmanian system strength nodes in this 2025 system strength report.

**Table 75 Minimum fault level requirements for Tasmania**

Node	Pre-contingent (secure) minimum fault level (MVA)	Post-contingent minimum fault level (MVA)	Contingency applicable for post-contingent level	Last changed
Burnie 110 kV	850 (750 after 2026)	560	Burnie 220 kV – Sheffield 220 kV line	2025 system strength report
George Town 220 kV	1,450	-	NA	2018 <i>System Strength Requirements Methodology</i>
Risdon 110 kV	1,330	-	NA	2018 <i>System Strength Requirements Methodology</i>
Waddamana 220 kV	1,400	-	NA	2018 <i>System Strength Requirements Methodology</i>

### A2.5.2.4 System strength nodes

AEMO has not declared any new system strength nodes nor set retirement dates for existing nodes in Tasmania in the 2025 system strength report. Possible future nodes in Tasmania are described in **Table 72**. These nodes may be declared in a future system strength report, subject to the changing needs of the power system.

**Table 76 Possible future nodes in Tasmania region and closures of existing nodes**

System strength node	Voltage and busbar	Effective date range	Purpose of new node
Hampshire Hills	220 kV Bus 1	On connection of forecast IBR in Tasmania	This node may provide better locations for forecast IBR in Western Tasmania as it connects.



### A2.5.2.5 Critical planned outages

No critical planned outages have been declared in Tasmania.

### A2.5.3 NSCAS assessment

AEMO assessed NSCAS needs in Tasmania over a five-year outlook period, under a range of demand, generation, and network project assumptions. This section summarises the results of these assessments relating to:

- voltage control and thermal loading (Section A2.5.3.1),
- rapid voltage change (Section A2.5.3.2),
- reactive margin (Section A2.5.3.3),
- system strength, over a three-year period (Section A2.5.3.4),
- inertia, over a three-year period (Section A2.5.3.5), and
- market benefit ancillary services (MBAS, Section A2.5.3.6).

**Table 77** provides an overview of the core scenarios studied for Tasmania. Section A2.8 provides further detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2024 NSCAS assessment.

**Table 77 Tasmania NSCAS scenarios and outcomes**

Case	Scenario assumptions	Year of assessment	NSCAS gap
High demand	Committed Projects Only	2025-26	No gap identified
	Committed Projects Only	2030-31	No gap identified
System strength	Modified ESOO scenario <sup>A</sup> ,	2025-26 to 2029-30	Deficits identified, but no gap declared <sup>B</sup>
System strength	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	Deficits identified, but no gap declared <sup>B</sup>
Inertia	Modified ESOO scenario <sup>A</sup> ,	2025-26 to 2029-30	Deficits identified, but no gap declared <sup>C</sup>
Inertia	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	Deficits identified, but no gap declared <sup>B</sup>

A. Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station closure notification (see <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>).

B. This deficit will be partially addressed by the solutions modelled parts of the System Strength RIT-T, but some deficit remains which could be addressed via contracts with generators or similar. See Section A2.2.2 for details.

C. An existing inertia shortfall under the transitional ISF rules remains in place until 2027-28.

#### A2.5.3.1 Voltage control and thermal loading

AEMO has assessed expected voltage control and thermal loading issues in Tasmania over a five-year outlook period. Studies focused on high demand conditions, as there has not been significant changes expected to worsen system security during minimum demand periods since last year’s studies. To study onerous voltage and thermal loading dispatch scenarios, Basslink was dispatched at high import across several generator dispatch profiles.

No gaps were identified under system normal operating conditions or following single credible contingency events.

### A2.5.3.2 Rapid voltage change

AEMO assessed the expected voltage change impacts of switching reactive plant in Tasmania. **Table 78** summarises the results of this analysis indicating maximum voltage deviations for a given case, the appropriate IEC Standard<sup>50</sup>, and whether that standard is met. The results demonstrate that the standard is met for all conditions assessed.

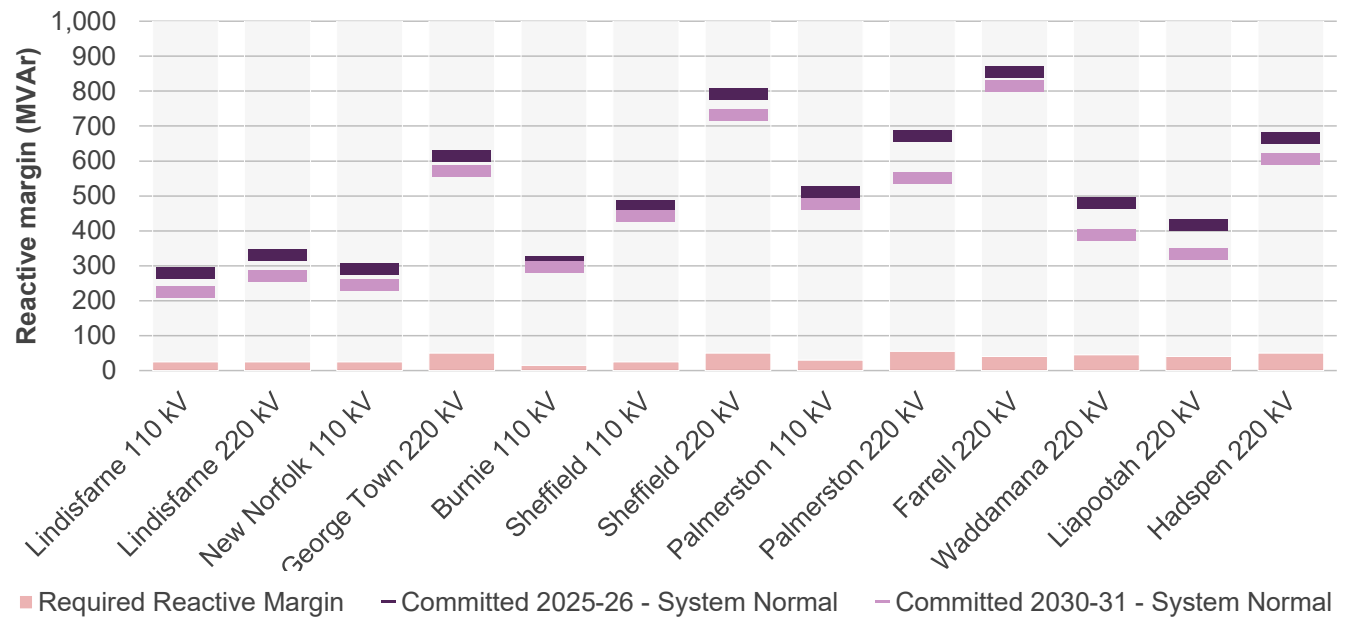
**Table 78 Rapid voltage change results for reactive plant switching in Tasmania**

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Maximum demand	Committed projects only	2025-26	1.49%	Risdon 110 kV	40 MVar capacitor at Risdon 110 kV	3-5%	Yes
	Committed projects only	2030-31	1.83%	Risdon 110 kV	40 MVar capacitor at Risdon 110 kV		Yes

### A2.5.3.3 Reactive margin

AEMO assessed whether the system normal reactive margins at critical buses in Tasmania are expected to remain above the system standard<sup>51</sup> of 1% of the local maximum fault level over the five-year outlook period. **Figure 47** summarises the results and indicates that all reactive margins are projected to meet the standard.

**Figure 47 Minimum reactive margin (MVar) observed for critical buses in Tasmania**



<sup>50</sup> Requirements for voltage fluctuation are defined by NER S5.1a.5 and TR IEC 61000.3.7, Table 6, Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed four within a 24-hour period, with each change allowing a permissible variation of 3-5% for network elements operated at greater than 230 kV and 5-6% for network elements operated at voltages between 35 kV and 230 kV.

<sup>51</sup> Required reactive margin is defined by NER S5.1.8 as “not less than 1% of the maximum fault level (in MVA) at the connection point”. For the purposes of this assessment, the required reactive margin was calculated based on the 2025-26 maximum fault level.

### A2.5.3.4 System strength

AEMO modelled projected fault levels under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>52</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in section A2.8.2.

The expected three phase fault current at each system strength node in Tasmania was compared against the latest minimum fault current requirements published in Section A2.5.2. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year<sup>53</sup>.

The results of this assessment are summarised in **Table 79**, and confirm that there are significant system strength deficits projected across Tasmania from 2025-26. TasNetworks identified contracting with existing owners of synchronous condensers and generation assets from December 2025 as the preferred option to meet system strength requirements in its System Strength RIT-T<sup>54</sup>. AEMO has confirmed through scenario-based analysis that this planned portfolio of contracts supplied by TasNetworks is sufficient to meet minimum fault level requirements in Tasmania for all future dispatch configurations until the end of the portfolio’s coverage period in 2029-30. TasNetworks will commence a new RIT-T assessing system strength requirements for 2029-30 and beyond.

**Table 79 Tasmania fault level requirements and identified deficits against the requirements**

System strength node	Fault level requirement (MVA)	Identified deficit in the Modified ESOO scenario (MVA)					Identified deficit in the Modified ESOO scenario with modelled parts of the RIT-T solutions (MVA)				
		2025-26	2026-27	2027-28	2028-29	2029-30	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Burnie 110 kV</b>	750*	422	306	328	374	404	0	0	0	0	404
<b>George Town 220 kV</b>	1,450	826	790	839	930	986	0	0	0	0	986
<b>Risdon 110 kV</b>	1,330	508	493	532	674	749	0	0	0	0	749
<b>Waddamana 220 kV</b>	1,400	591	539	611	746	833	0	0	0	0	833

\*Burnie 110 kV has a fault level requirement of 850 MVA for the 2025-26 period, which is reduced to 750 MVA in the following years.

Section A2.5.2 provides additional detail on the calculation of fault level requirements. Detailed projected fault levels per system strength node are shown below, with and without modelled parts of the RIT-T solutions. To represent the expected RIT-T generator and synchronous condenser contracts, AEMO has capped the projected fault levels at the minimum requirements in the modelled parts of the RIT-T solution fault level duration curves until 2029-30.

<sup>52</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

<sup>53</sup> 99.87% is equivalent to three standard deviations above the mean. See [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc_lang=en).

<sup>54</sup> TasNetworks, *Meeting the System Strength Standard in Tasmania from December 2025 onward*, 2025, at <https://www.tasnetworks.com.au/config/getattachment/d15ecd38-f6a3-4b6c-bc68-61909ef48c15/tasnetworks-system-strength-rit-t-pacr-june-2025.pdf>.

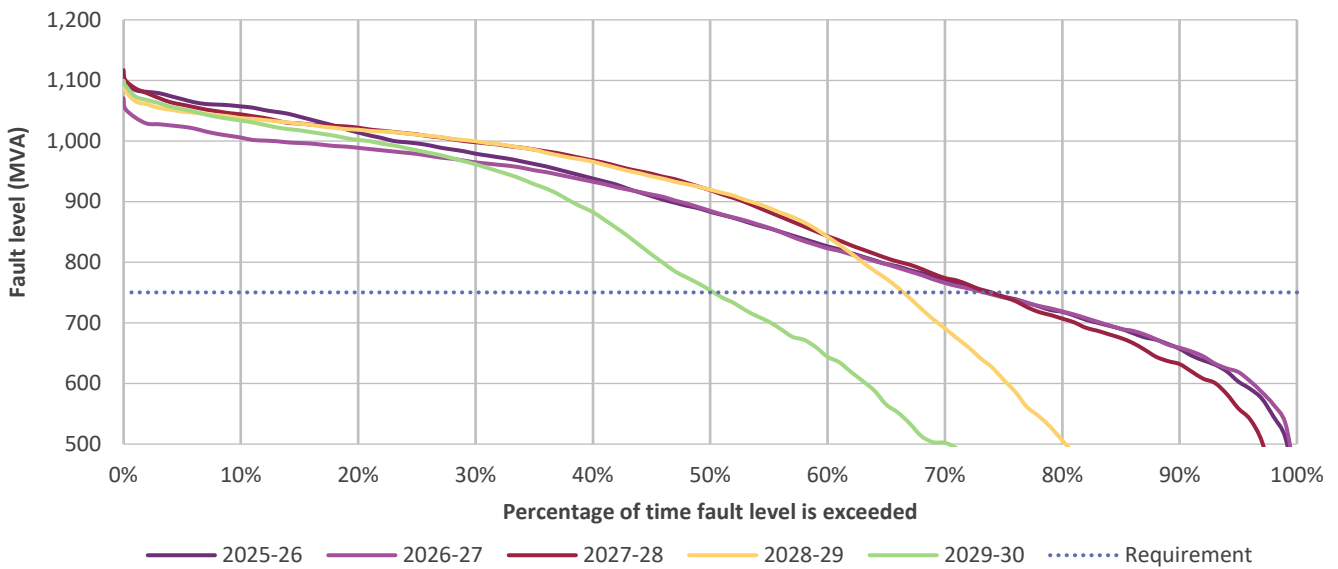


### Burnie 110 kV

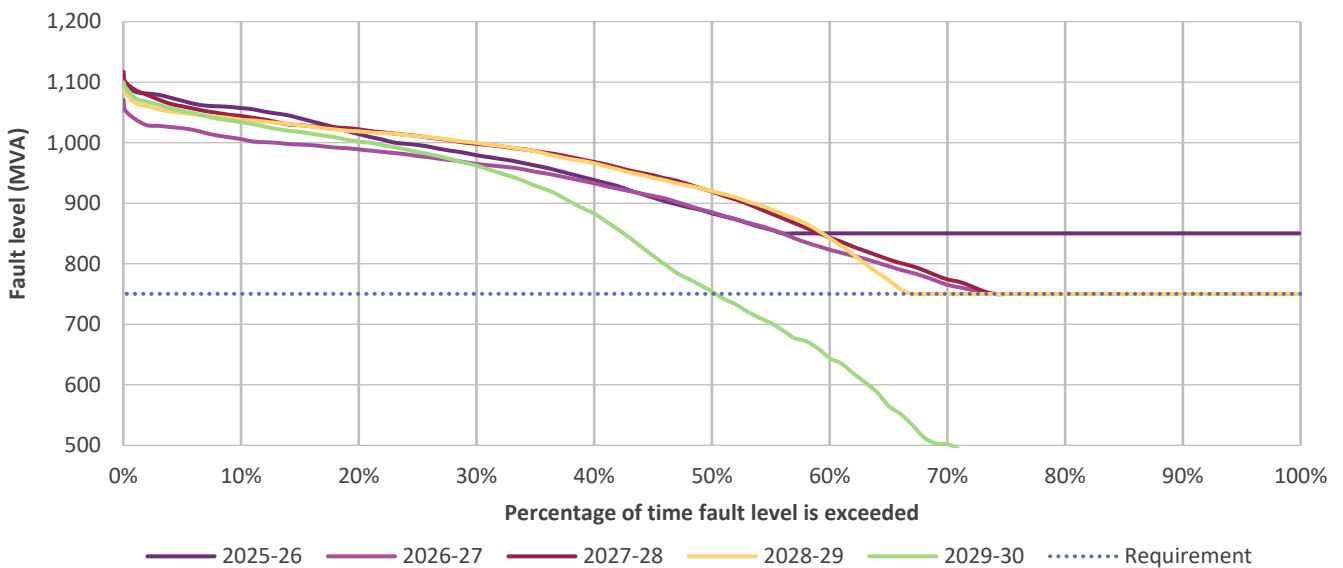
**Figure 48** shows the projected three phase fault level at the Burnie 110 kV node without the modelled parts of the RIT-T solution. Burnie sees deficits at the 99.87th percentile in all forecast years. **Figure 49** shows projected fault levels after implementing the planned portfolio of contracts supplied by TasNetworks. This figure shows the minimum fault level capped at the fault level requirement.

The summarised results for the 99.87th percentile values from these figures are in **Table 80**. TasNetworks’ planned portfolio of contracts is projected to address the deficits at Burnie until the end of the portfolio’s coverage period in 2029-30. In 2026, TasNetworks will commence a new RIT-T assessing system strength requirements for 2029-30 and beyond.

**Figure 48 Burnie node fault level duration curves and minimum requirement**



**Figure 49 Burnie node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 80 Burnie node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Burnie 110 kV	Minimum fault level requirement (MVA)	850	750	750	750	750
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	428	444	422	376	346
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	850	750	750	750	346
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	422	306	328	374	404
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	404
	NSCAS gap (Yes/No)*	No	No	No	No	No

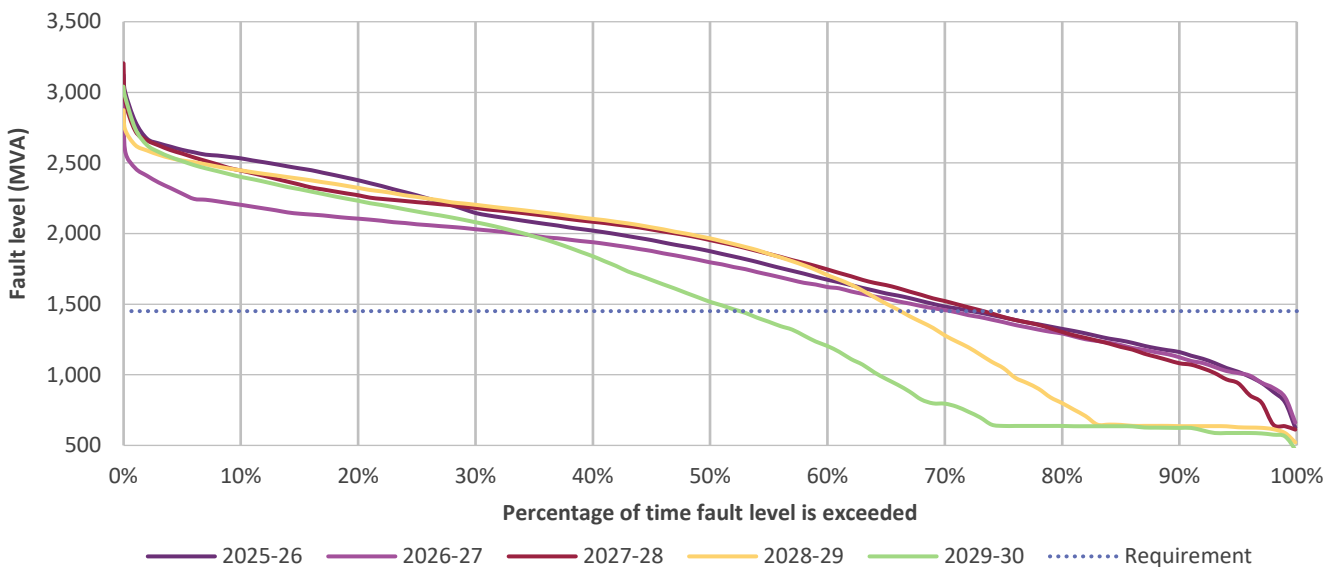
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### George Town 220 kV

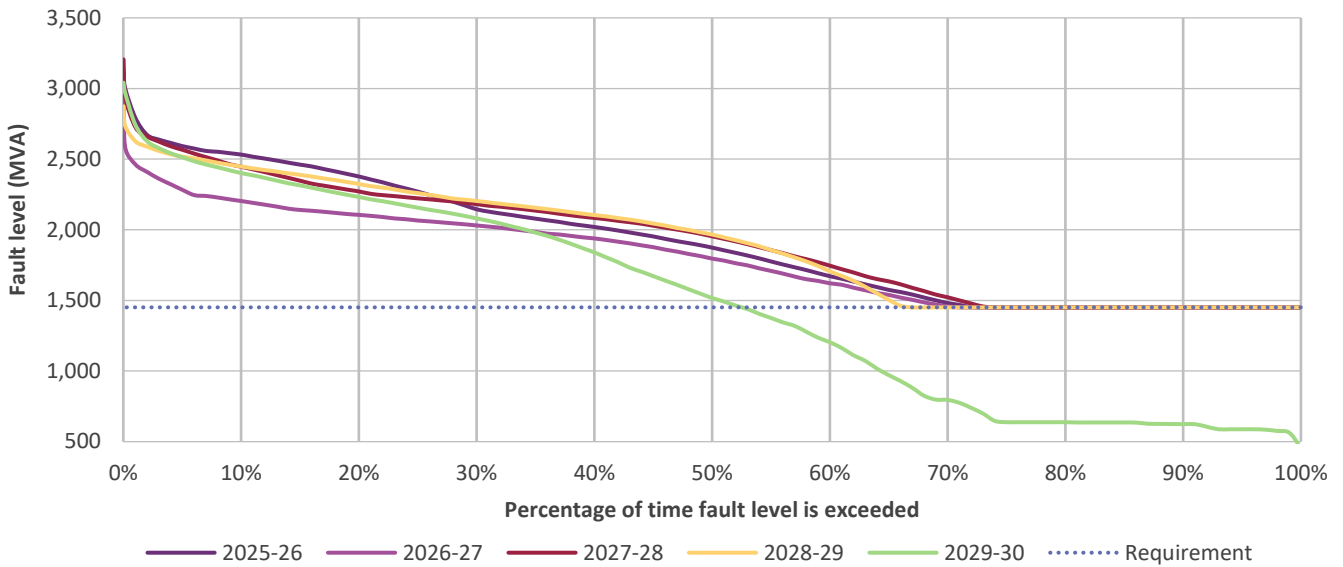
Figure 50 shows the projected three phase fault level at the George Town 220 kV node without the modelled parts of the RIT-T solution. George Town sees deficits at the 99.87th percentile in all forecast years. Figure 51 shows projected fault levels after implementing the planned portfolio of contracts supplied by TasNetworks. This figure shows the minimum fault level capped at the fault level requirement.

The summarised results for the 99.87th percentile values from these figures are in Table 81. TasNetworks’ planned portfolio of contracts is projected to address the deficits at George Town until the end of the portfolio’s coverage period in 2029-30. In 2026, TasNetworks will commence a new RIT-T assessing system strength requirements for 2029-30 and beyond.

**Figure 50 George Town node fault level duration curves and minimum requirement**



**Figure 51** George Town node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution



**Table 81** George Town node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
George Town 220 kV	Minimum fault level requirement (MVA)	1,450	1,450	1,450	1,450	1,450
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	624	660	611	520	464
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	1,450	1,450	1,450	1,450	464
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	826	790	839	930	986
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	986
	NSCAS gap (Yes/No)*	No	No	No	No	No

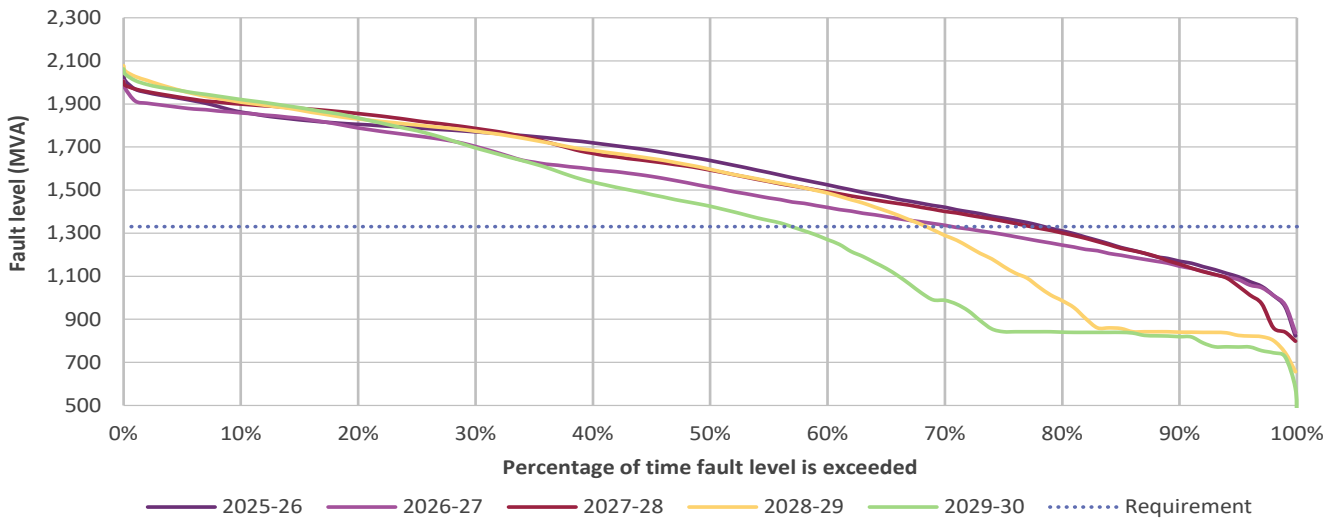
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Risdon 110 kV

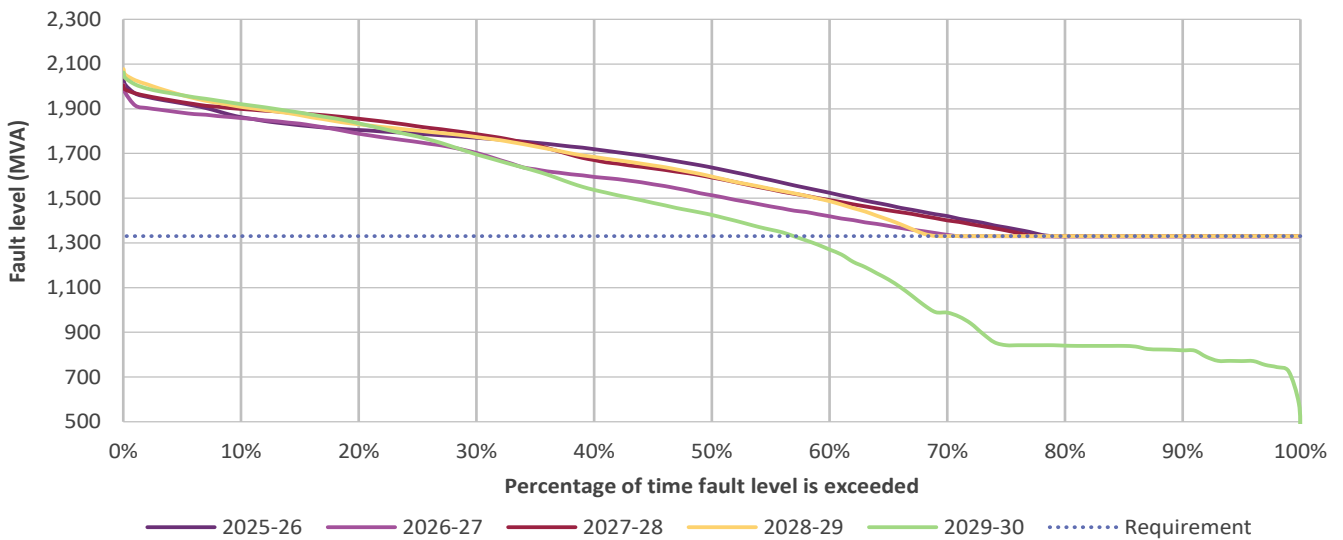
Figure 52 shows the projected three phase fault level at the Risdon 110 kV node without the modelled parts of the RIT-T solution. Risdon sees deficits at the 99.87th percentile in all forecast years. Figure 53 shows projected fault levels after implementing the planned portfolio of contracts supplied by TasNetworks. This figure shows the minimum fault level capped at the fault level requirement.

The summarised results for the 99.87th percentile values from these figures are in Table 82. TasNetworks’ planned portfolio of contracts is projected to address the deficits at Risdon the end of the portfolio’s coverage period in 2029-30. In 2026, TasNetworks will commence a new RIT-T assessing system strength requirements for 2029-30 and beyond.

**Figure 52 Risdon node fault level duration curves and minimum requirement**



**Figure 53 Risdon node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 82 Risdon node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Risdon 110 kV	Minimum fault level requirement (MVA)	1,330	1,330	1,330	1,330	1,330
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	822	837	798	656	581
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	1,330	1,330	1,330	1,330	581
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	508	493	532	674	749
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	749
	NSCAS gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

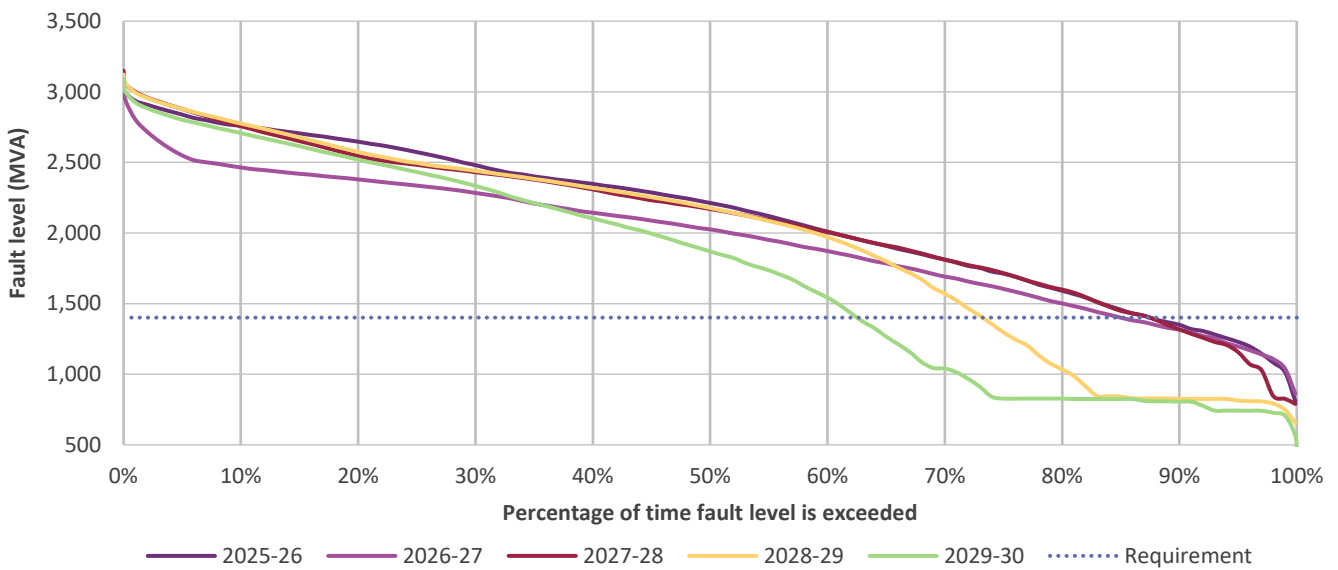


### Waddamana 220 kV

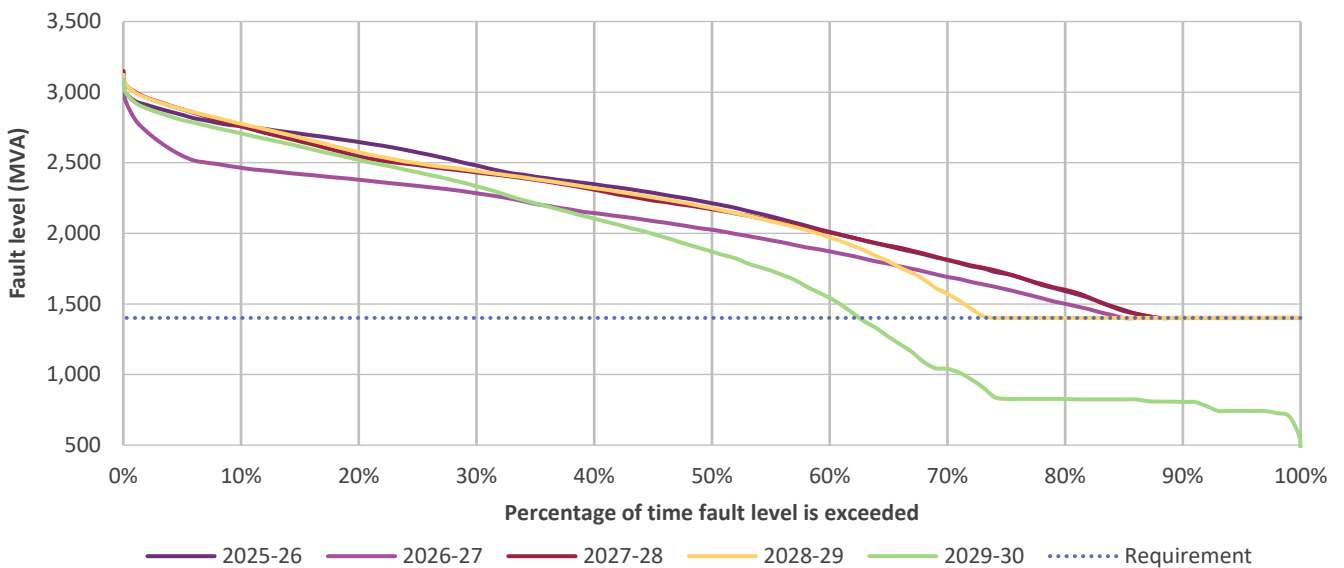
**Figure 54** shows the projected three phase fault level at the Waddamana 220 kV node without the modelled parts of the RIT-T solution. Waddamana sees deficits at the 99.87th percentile in all forecast years. **Figure 55** shows projected fault levels after implementing the planned portfolio of contracts supplied by TasNetworks. This figure shows the minimum fault level capped at the fault level requirement.

The summarised results for the 99.87th percentile values from these figures are in **Table 83**. TasNetworks’ planned portfolio of contracts is projected to address the deficits at Waddamana unit the end of the portfolio’s coverage period in 2029-30. In 2026, TasNetworks will commence a new RIT-T assessing system strength requirements for 2029-30 and beyond.

**Figure 54 Waddamana node fault level duration curves and minimum requirement**



**Figure 55 Waddamana node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 83 Waddamana node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Waddamana 220 kV</b>	Minimum fault level requirement (MVA)	1,400	1,400	1,400	1,400	1,400
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	809	861	789	654	567
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	1,400	1,400	1,400	1,400	567
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	591	539	611	746	833
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	833
	NSCAS gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### A2.5.3.5 Inertia

AEMO modelled projected inertia under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>55</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in section A2.8.2.

AEMO assessed the expected levels of available inertia in Tasmania against the latest inertia requirements published in the Section A2.5.1. Tasmania is not subject to the system-wide inertia level, so this assessment considers only the islanded regional requirement, and the likelihood of islanding events. Section A2.5.1 provides further detail on the calculation and application of these inertia requirements.

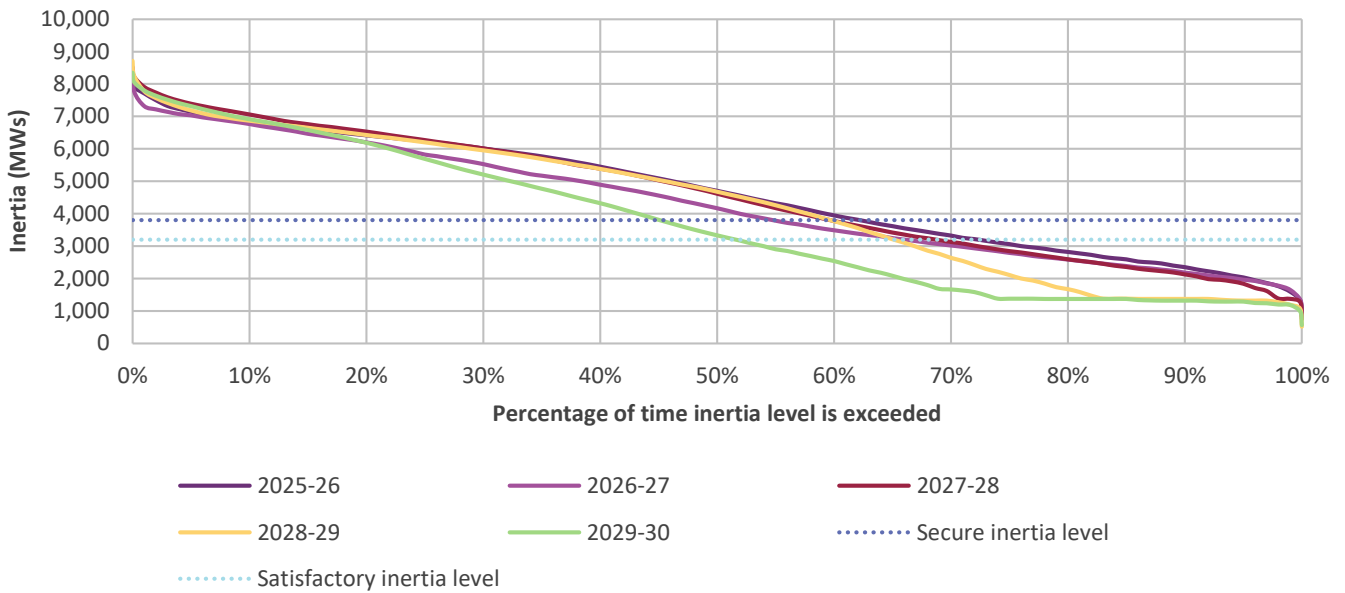
### Secure inertia requirements assessment for Tasmania

AEMO's assessment of the resulting inertia needs, summarised in **Figure 56**, indicates an inertia deficit in Tasmania of between 2,482 MWs and 2,822 MWs from 2025-26 until the end of the horizon against the secure inertia level.

TasNetworks is progressing inertia remediation measures in parallel with its completed System Strength RIT-T. AEMO will continue to work with TasNetworks to track the progress of its remediation activities through joint planning functions.

<sup>55</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station 'two-shifting', and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

**Figure 56** Projected inertia for the five-year outlook, Modified ESOO scenario, Tasmania



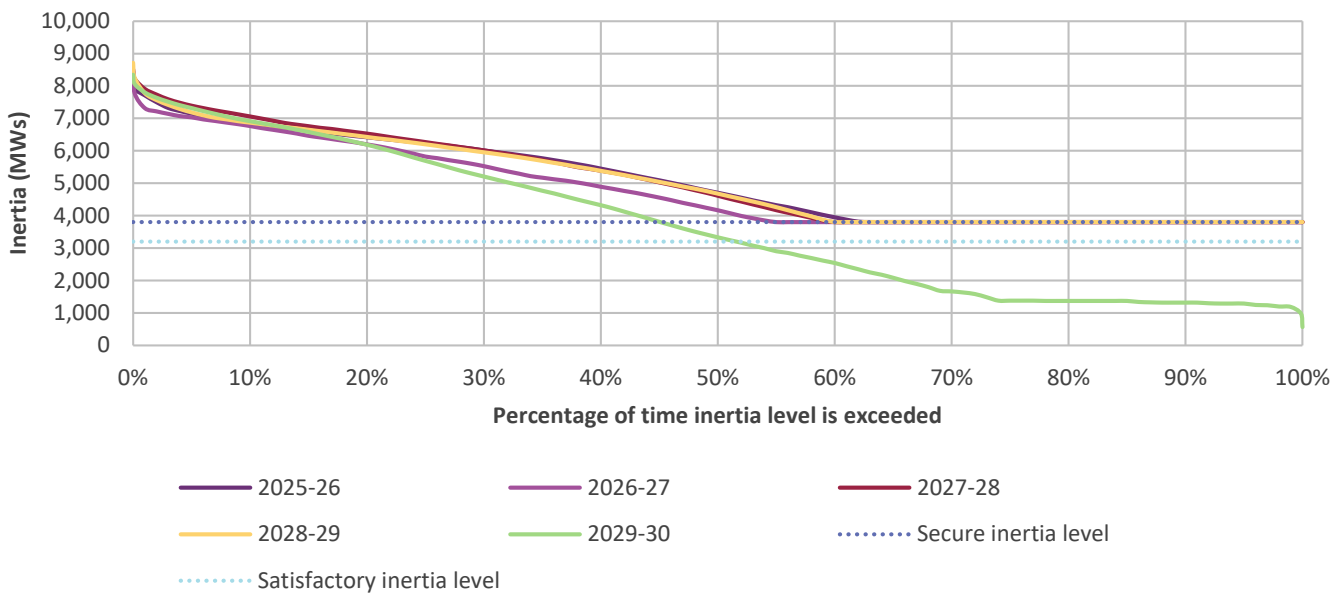
**Table 84** Secure inertia level and projections, Modified ESOO scenario, Tasmania

	2025-26	2026-27	2027-28	2028-29	2029-2030
<b>Secure inertia level (MWs)</b>	3,800	3,800	3,800	3,800	3,800
<b>Available inertia 99.87% of the time (MWs)</b>	1,318	1,337	1,266	1,059	978
<b>Inertia deficit (MWs)</b>	2,482	2,463	2,534	2,741	2,822
<b>NSCAS gap (Yes/No)*</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.

\*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

**Figure 57** Projected inertia for the five-year outlook, Modified ESOO scenario with modelled parts of the RIT-T solution, Tasmania



**Table 85 Secure inertia level and projections, Modified ESOO scenario with modelled parts of the RIT-T solution, Tasmania**

	2025-26	2026-27	2027-28	2028-29	2029-30
Secure inertia level (MWs)	3,800	3,800	3,800	3,800	3,800
Available inertia 99.87% of the time (MWs)	3,800	3,800	3,800	3,800	978
Inertia deficit (MWs)	0	0	0	0	2,822
NSCAS gap (Yes/No)*	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.

\*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

### A2.5.3.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Tasmania. **Table 86** provides a comparison of binding hours and marginal values for the top impact constraints in Tasmania<sup>56</sup>. All constraints with a marginal value exceeding \$60,000 per year have previously been considered by TasNetworks. In each case, a risk status, project, control scheme, or other mitigation strategy has been identified. These options are being monitored through the TasNetworks annual TAPR process and may trigger action if market benefits exceed remediation costs.

**Table 86 Tasmania high-impact constraint summary for 2024 calendar year**

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
T>T_NIL_110_1	Out = NIL, avoid pre-contingent O/L of the Derby to Scottsdale Tee 110 kV line, feedback.	0.8M (↑\$0.8M)	283	Constraint binding is driven by Musselroe Wind Farm generation and bidding and local load. There are no planned augmentations or updates to the existing runback scheme at this stage.
T::T_NIL_1	Out = NIL, prevent transient instability for fault and trip of a Farrell to Sheffield line, Swamp if less than 3 synchronous West Coast units generating or Farrell 220kV bus coupler open or Hampshire 110kV line is closed.	0.3M (↓\$0.3M)	638	Planned future augmentation of Sheffield–Palmerston 220 kV will assist this constraint.
T_ROCOF_3	Out = NIL, limit non-synchronous generation and Basslink to prevent high Rate of Change of Frequency in TAS following fault and trip of generation during periods of low TAS inertia	0.1M (↑\$0.1M)	102	Constraint to manage RoCoF in Tasmania.

Note: From annual NEM Constraint Report, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams>. Constraints have been prioritised as per calendar year 2024 data

<sup>56</sup> Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is in the NSCAS Description and Quantity Procedure, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0)

## A2.6 Victoria

- AEMO has confirmed the existing voltage control and thermal loading risks at Deer Park, however Powercor and VicGrid are progressing solutions. This risk is associated with large load growth projected at Deer Park. Powercor is progressing a RIT-T<sup>57</sup> to address transformer overloading and localised issues, while VicGrid is progressing augmentations around Keilor and Geelong as a high priority project identified in the 2025 Victorian Transmission Plan<sup>58</sup>. A System Overload Control Scheme (SOCS) addresses this issue in the interim. On this basis, AEMO is flagging this as an emerging risk rather than a NMAS gap, and will continue to monitor progress and solutions to manage this risk.
- AEMO has confirmed the previously identified thermal overloading risks during high demand periods post Yallourn retirement, and notes that VicGrid is progressing a number of priority investment assessments to address this.
- An inertia deficit of 3,235 MWs to 7,104 MWs from 2027-28 against the sub-network allocation has been identified. This deficit is partially mitigated by synchronous condensers due to be installed as part of the System Strength RIT-T, however a residual deficit of around 3,000 MWs could be managed via contracts with generators or similar. VicGrid is required to ensure sufficient inertia is available to meet its full inertia sub-network allocation of 11,800 MWs from 2 December 2027.
- Inertia levels fall below the sub-network allocation from 2025-26. However, during the ISF transitional period (up to 2 December 2027), inertia from neighbouring regions can be shared with Victoria, and AEMO has confirmed that sufficient shared inertia is available to avoid a deficit over this period.
- System strength deficits ranging from 384 MVA to 2,031 MVA at Moorabool, Hazelwood and Thomastown have been identified from 2027-28. This risk is mostly addressed by the synchronous condensers as part of the preferred option in the System Strength RIT-T, however a residual deficit of 348 MVA at Hazelwood remains in 2027-28, which could be managed via contracts with generators or similar. This is described in the RIT-T but was not modelled due to insufficient information.

This section covers:

- inertia requirements, including the satisfactory and secure levels of inertia when planning for islanded operation, and the regional allocation of the system-wide level over a 10-year horizon,
- system strength requirements, comprising the identification of system strength nodes, minimum fault level requirements over a 10-year horizon, and the 10-year forecast of IBR, used to determine the efficient level of system strength, and
- NSCAS assessment details, including considerations for both inertia and system strength projections against the requirements.

<sup>57</sup> Powercor, June 2025, see [https://media.powercor.com.au/wp-content/uploads/2025/06/24165310/Deer-Park-TS-PSCR\\_FINAL.pdf](https://media.powercor.com.au/wp-content/uploads/2025/06/24165310/Deer-Park-TS-PSCR_FINAL.pdf).

<sup>58</sup> VicGrid, 2025, see <https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan>.

### A2.6.1 Inertia requirements

AEMO has confirmed that the inertia requirements for Victoria remain unchanged this year. **Table 87** provides a summary of the *inertia requirements* for Victoria, including the *satisfactory* and *secure inertia levels* when planning for potential islanded operation, and the *sub-network allocation* of the *system-wide inertia level*. VicGrid is required to ensure sufficient inertia services are available to meet its *sub-network allocation* from 2 December 2027.

In addition to the system-wide inertia requirements, AEMO has determined *minimum regional interconnected inertia levels* for each region. While these levels are not regulatory obligations under NER 5.20B.2, they represent the practical amount of inertia that is required to be available within the region to withstand a contingency within that region, as detailed in Section A2.1.

For Victoria, the minimum regional interconnected inertia level is 8,000 MWs. If regional inertia falls below this threshold, supporting inertia from neighbouring regions may be insufficient to maintain compliance with the FOS following a credible contingency, due to high network impedances between regions. The calculation and operational application of these minimum regional interconnected inertial levels are described in detail in Section A2.1.

**Table 87** Victoria inertia requirements from 2 December 2025 to 1 December 2035

Quantity	Value
Satisfactory inertia level	13,700 MWs
Secure inertia level	15,400 MWs
Inertia sub-network allocation	11,800 MWs
Minimum regional interconnected inertia level	8,000 MWs
Likelihood of islanding	Unlikely

#### A2.6.1.1 Likelihood of islanding

**Table 88** presents the criteria assessed when determining the likelihood of the Victorian inertia sub-network islanding from the remainder of the system.

**Table 88** Assessment of the likelihood of Victoria islanding

Criterion	Victoria
Inertia levels compared to secure inertia level	<i>Inertia</i> levels forecast to be below the <i>secure inertia level</i> across the horizon.
Inertia sub-network allocation	11,800 MWs
Existing interconnections	Two 220 kV AC, three 330 kV AC, and one 132 kV AC connection to New South Wales. One 275 kV AC double-circuit to South Australia. One DC link to South Australia. One DC link to Tasmania.
Future interconnections and status	VNI West: 500 kV AC double-circuit to New South Wales. Project Marinus: Two DC links to Tasmania (Stage 1 and Stage 2) Project EnergyConnect Stage 2
History of islanding	N/A
Applicable control schemes	N/A
Likelihood of islanding after contingency event	Unlikely

### A2.6.1.2 Co-optimisation with contracted FFR and 1-Second FCAS

The amount of FFR available in the NEM has increased rapidly in the last half a decade due to significant battery connections. The 1-Second FCAS market was introduced as a mechanism for procuring FFR to meet the FOS.

The role of the inertia requirements is to slow down the change in frequency which occurs after a generation or load contingency until FCAS responds to contain and restore frequency. Following the staged introduction of 1-Second FCAS from 2023, less inertia has been required because FCAS now responds faster.

The NEM is now reaching a point where additional FFR may no longer allow the inertia requirements to decrease. In every region, the limiting factor in meeting the FOS under current levels of FFR is no longer the nadir but rather RoCoF over the first 300-500 ms. FFR is very effective at limiting the frequency nadir, but inertia is the most appropriate tool for limiting RoCoF over the first 300-500 ms.

In previous inertia reports, FFR curves have been used as a tool to determine the trade-off between inertia and FFR. Continued work studying this phenomenon in PSS®E shows these curves are unlikely to extrapolate to the levels of FFR currently available in the NEM. AEMO intends to consider the impact of additional FFR on the inertia requirements on a case-by-case basis.

BESS are still able to contribute significantly to meeting the inertia requirements by providing synthetic inertia which is similarly as effective as synchronous inertia in limiting RoCoF.

### A2.6.2 System strength requirements

AEMO has confirmed the system strength nodes, and their minimum fault level requirements continue are maintained at the present values in the 2025 system strength report. AEMO has also updated the IBR projections in Victoria used to determine the efficient level of system strength, based on the latest available preliminary information from the Draft 2026 ISP.

#### A2.6.2.1 Summary of IBR projections for Victoria

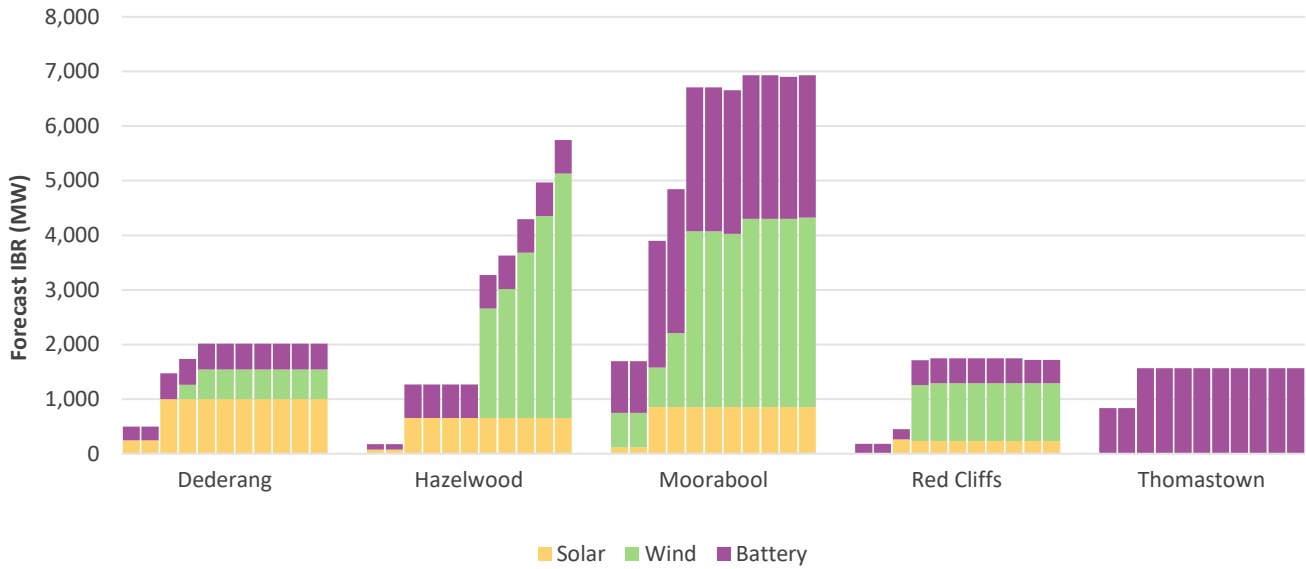
AEMO's 10-year projection of the level and type of IBR and schedule 5.3a plant for Victorian system strength nodes under NER 5.20C.1(c)(2)(ii) is summarised in **Figure 58**. As defined in NER S5.1.14(a), **Figure 58** defines the 'efficient level' IBR forecast component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028.

This IBR forecast is primarily based on the Draft 2026 ISP modelling, which AEMO has allocated to specific nodes based on local network knowledge and engineering judgement. The Draft 2026 ISP is published after this system strength report<sup>59</sup> and projections may slightly differ to the preliminary results which informed this IBR forecast.

AEMO expects that VicGrid, as the SSSP in Victoria, may engage in joint planning with neighbouring SSSPs to identify any investment efficiencies when assessing the nature of solutions required to meet these requirements. AEMO supports SSSPs considering the latest available information and announcements to adjust this IBR forecast for use in their planning activities between publications of the system strength report, as outlined in Section A2.8.1.1.

<sup>59</sup> The Draft 2026 ISP will be published on 10 December 2025 as per the ISP Timetable, at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp>.

**Figure 58** Forecasts of IBR and market schedule 5.3a plant for 10 years from 2025-26, Victoria



A2.6.2.2 Nodal IBR projections for Victoria

Dederang 220 kV

Table 89 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 89** Dederang node utility-scale IBR projections

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Dederang 220 kV	Solar	747	250	250	999	999	999	999	999	999	999	999	999
	Wind	0	0	0	0	264	544	544	544	544	544	544	544
	Battery	0	250	250	474	474	474	474	474	474	474	474	474
	<b>Total IBR</b>	<b>747</b>	<b>500</b>	<b>500</b>	<b>1,473</b>	<b>1,737</b>	<b>2,017</b>	<b>2,017</b>	<b>2,017</b>	<b>2,017</b>	<b>2,017</b>	<b>2,017</b>	<b>2,017</b>

Hazelwood 500 kV

Table 90 provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 90** Hazelwood node utility-scale IBR projections

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Hazelwood 500 kV	Solar	0	77	77	658	658	658	658	658	658	658	658	658
	Wind	127	0	0	0	0	0	0	2,000	2,360	3,026	3,693	4,475
	Battery	200	100	100	614	614	614	614	614	614	614	614	614
	<b>Total IBR</b>	<b>327</b>	<b>177</b>	<b>177</b>	<b>1,272</b>	<b>1,272</b>	<b>1,272</b>	<b>1,272</b>	<b>3,272</b>	<b>3,632</b>	<b>4,298</b>	<b>4,965</b>	<b>5,747</b>

## Moorabool 220 kV

**Table 91** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 91 Moorabool node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Moorabool 220 kV	Solar	0	119	119	857	857	857	857	857	857	857	857	857
	Wind	5,255	629	629	721	1,356	3,219	3,219	3,167	3,444	3,444	3,444	3,470
	Battery	414	947	947	2,320	2,631	2,631	2,631	2,631	2,631	2,631	2,601	2,601
	Total IBR	5,669	1,695	1,695	3,898	4,844	6,707	6,707	6,655	6,932	6,932	6,902	6,928

## Red Cliffs 220 kV

**Table 92** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 92 Red Cliffs node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Red Cliffs 220 kV	Solar	750	0	0	263	233	233	233	233	233	233	233	233
	Wind	15	0	0	0	1,022	1,057	1,057	1,057	1,057	1,057	1,057	1,057
	Battery	30	185	185	188	460	460	460	460	460	460	430	430
	Total IBR	795	185	185	451	1,715	1,750	1,750	1,750	1,750	1,750	1,750	1,720

## Thomastown 220 kV

**Table 93** provides an overview of projected IBR by technology and year, which forms the basis of the efficient level requirement for system strength at this node.

**Table 93 Thomastown node utility-scale IBR projections**

Node	Type	Existing (MW)	Projected additional IBR by financial year ending (MW)										
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Thomastown 220 kV	Solar	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	69	0	0	0	0	0	0	0	0	0	0	0
	Battery	267	840	840	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565
	Total IBR	336	840	840	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565

## A2.6.2.3 Minimum fault level requirements for Victoria

The Victorian minimum fault level requirements under NER 5.20C.1(c)(2)(i) applicable for planning purposes over the next 10 years are summarised in **Table 94** below. The minimum fault level requirements under NER 5.20C.1(c)(1) applicable for operational purposes over the next year are in Section A2.9. As defined in NER S5.1.14(a), the values in the table define the

minimum fault level component of the *system strength standard specification* for three years from the publication of this report – that is, for the year commencing 2 December 2028.

No changes have been made to the minimum fault levels for Victoria in this 2025 system strength report.

**Table 94 Minimum fault level requirements for Victoria**

Node	Pre-contingent (secure) minimum fault level (MVA)	Post-contingent minimum fault level (MVA)	Contingency applicable for post-contingent level	Last changed
Dederang 220 kV	3,500	3,300	South-Morang Transformer 500/330 kV	2020 <i>System Strength Report</i>
Hazelwood 500 kV	7,700	7,150	Hazelwood – South Morang 500 kV line	2020 <i>System Strength Report</i>
Moorabool 220 kV	4,600	4,050	Moorabool Transformer 500/220 kV	2020 <i>System Strength Report</i>
Red Cliffs 220 kV	1,786	1,036	Red Cliff – Wemen 220 kV line	2021 <i>System Strength Report</i>
Thomastown 220 kV	4,700	4,500	Thomastown (Bus B) – Keilor 220 kV line	2020 <i>System Strength Report</i>

#### A2.6.2.4 System strength nodes

AEMO has not declared any new system strength nodes, nor set retirement dates for existing nodes in the 2025 system strength report. Possible future nodes in Victoria are described in **Table 95**. These nodes may be declared in a future system strength report, subject to the changing needs of the power system.

**Table 95 Possible future nodes in Victoria region and closures of existing nodes**

System strength node	Voltage and busbar	Effective date range	Purpose of new node
<b>Mortlake</b>	500 kV Bus 1	On connection of significant IBR in Victoria	This node is located within the V5 South West Victoria REZ, where large amounts of future IBR may connect. It may also provide a node suitable for assessing critical planned outages on the interconnector with other regions.
<b>Bulgana</b>	220 kV Bus 1	On connection of significant IBR in Victoria	This node is located between the Western Victorian REZs V3 Wimmera Grampians and V4 Wimmera Southern Mallee, where future transmission augmentation projects will unlock network capacity to connect new IBR generation.

#### A2.6.2.5 Intermittent sub-synchronous oscillations in South West Victoria

AEMO has observed intermittent oscillations in South West Victoria and neighbouring parts of South Australia in late 2024 and 2025. The root cause of these oscillations is still under ongoing investigation. Investigations to date have not found evidence to suggest that a change in system strength requirements or retuning of generators is needed. AEMO will update the system strength requirements in future if needed based on the outcome of further investigations.

#### A2.6.2.6 Critical planned outages

SSSPs are expected to consider critical planned outages in their proposed system strength solutions on a case-by-case basis<sup>60</sup>. AEMO has declared several critical planned outages as impactful for maintaining system strength in Victoria, and

<sup>60</sup> AEMO, *System Strength Requirements Methodology*, section 4.5, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/system-strength-requirements-methodology-v21.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/system-strength-requirements-methodology-v21.pdf).

these are presented in **Table 96**. AEMO has updated this table to reflect the changed line sections in the South West Victoria corridor following the cut-in of Mortlake Terminal station into the Haunted Gully to Tarrone line since the 2024 *System Strength Report*.

**Table 96 Critical planned outages in Victoria for each system strength node**

Affected node	Network outage	Reason for consideration as critical
<b>Dederang (Darlington Point in New South Wales)</b>	Dederang to Wodonga 330 kV line	Fault level at Darlington Point drops below requirement for another contingency.
<b>Moorabool Thomastown</b>	Hazelwood to Loy Yang 1 or 2 or 3 500 kV line	One of the specified minimum synchronous unit combinations must be dispatched <sup>A</sup> .
	Moorabool to Sydenham 1 or 2 500 kV line	
	South Morang to Rowville 500 kV line	
<b>Moorabool</b>	500/220 kV Transformer at Moorabool	Low fault level at Moorabool.
	Heywood to Mortlake 500 kV line	Significant system strength impact along Victoria to South Australia corridor for another contingency.
	Haunted Gully to Mortlake 500 kV line	
	Tarrone to Heywood 500 kV line	
	Mortlake to Tarrone 500 kV line	
	Moorabool to Sydenham 1 or 2 500 kV line	
	Cressy to Moorabool No.1 500 kV line	
	Cressy to Moorabool No.2 500 kV line	
	Cressy to Haunted Gully 500 kV line	
	Cressy to Mortlake 500 kV line	

A. See [https://aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/congestion-information/victorian-transfer-limit-advice-outages.pdf?la=en](https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/victorian-transfer-limit-advice-outages.pdf?la=en).

### A2.6.3 NSCAS assessment

AEMO assessed NSCAS needs in Victoria over a five-year outlook period, under a range of demand, generation, and network assumptions. This section summarises the results of these assessments relating to:

- voltage control and thermal loading (Section A2.6.3.1),
- rapid voltage change (Section A2.6.3.2),
- reactive margin (Section A2.6.3.3),
- system strength, over a three-year period (Section A2.6.3.4),
- inertia, over a three-year period (Section A2.6.3.5), and
- market benefit ancillary services (Section A2.6.3.6).

**Table 97** provides an overview of the core scenarios studied for Victoria. Section A2.8 has more detail on the specific input sources, cut-off dates, modelling assumptions, and study methodology used for the 2025 NSCAS assessment. Minimum demand was not studied, given there was only a slight increase in minimum demand forecast in the 2025 forecasts<sup>61</sup>.

<sup>61</sup> See <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal> for details.

**Table 97 Victorian NSCAS scenarios and outcomes**

	Scenario assumptions	Year of assessment	NSCAS gap
<b>High demand</b>	<i>Committed Projects Only</i>	2025-26	No NSCAS gap declared. An immediate voltage risk at Deer Park Terminal Station. Vic System Overload Control Scheme (SOCS) in service to manage this issue.
	<i>Committed Projects Only</i>	2030-31	No NSCAS gap declared. An emerging voltage and thermal risk at Deer Park Terminal Station. Powercor and VicGrid are progressing investment testing to remediate this issue in time.
	<i>System typical Committed Projects Only – Basslink out of service</i>	2030-31	No NSCAS gap declared. An emerging thermal and reliability risk in meeting growing demand considering committed transmission, generation and storage developments.
<b>System strength</b>	Modified ESOO scenario <sup>A</sup>	2025-26 to 2029-30	Deficits identified, but no NSCAS gap declared <sup>B</sup> .
<b>System strength</b>	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	Deficits identified, but no NSCAS gap declared <sup>B</sup> .
<b>Inertia</b>	Modified ESOO scenario <sup>A</sup>	2025-26 to 2029-30	Deficits identified, but no NSCAS gap declared <sup>B</sup> .
<b>Inertia</b>	Modified ESOO scenario <sup>A</sup> ,+ modelled parts of the System Strength RIT-T preferred options.	2025-26 to 2029-30	Deficits identified, but no NSCAS gap declared <sup>B</sup> .

A. Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station closure notification (see <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>).

B. A deficit was identified against the requirements for system strength and inertia. This deficit will be partially addressed by the solutions modelled parts of the System Strength RIT-T, but some deficit remains which could be addressed via contracts with generators or similar. See section A2.8.2 for details

### A2.6.3.1 Voltage control and thermal loading

AEMO assessed expected voltage control and thermal loading issues in Victoria over a five-year outlook period, under a maximum demand scenario. This included testing several different assumptions relating to committed and announced changes to both generation and transmission projects.

#### Thermal overloads and voltage control risk at Deer Park Terminal Station

The 2025 NSCAS studies confirmed the previously identified voltage control and thermal overload risks near Deer Park. This is predominantly driven by large load growth projected at Deer Park. A System Overload Control Scheme (SOCS) has been commissioned to manage this issue until permanent solutions identified by both Powercor and VicGrid are completed. The control scheme enables higher pre-contingent loading on the Geelong – Deer Park 220 kV and Geelong – Keilor 220 kV lines. The control scheme also responds post contingent to remove any overload following a contingency of a 220 kV circuit between Geelong and Keilor. It is also noted that other RIT-T and VicGrid transmission plan projects<sup>62</sup> are in progress to deliver greater thermal capacity to Deer Park, further mitigating the risk of thermal overloads.

The 2025 NSCAS studies also confirmed voltage risks following credible contingencies on the 220 kV network near Deer Park, and a need for additional reactive support near Deer Park which grows over the NSCAS horizon. VicGrid and Powercor

<sup>62</sup> See <https://www.aemo.com.au/initiatives/major-programs/western-metropolitan-melbourne-reinforcement>, <https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan>, and <https://www.aemo.com.au/consultations/current-and-closed-consultations/pscr-ts-dpts>.

are progressing investment options to address the voltage risk at Deer Park<sup>63</sup>. There is an interim voltage risk until these projects deliver a solution, however VicGrid is investigating the ability of the existing SOCS to manage the under-voltage risks in addition to thermal loading risks.

### Yallourn retirement and thermal overloads risks during high demand periods

AEMO has confirmed the previously identified risk for thermal overloads during high demand. This is caused by transformer loading limits at key points between the 500 kV and 220 kV networks supplying Metropolitan Melbourne and thermal limits in Western Victoria where a majority of renewable generators are connected. These limits tightened following the announced retirement of Yallourn Power Station.

The transformer loading limits was identified as a priority limitation in the 2023 *Victorian Annual Planning Report (VAPR)*<sup>64</sup>. The report proposed a network switching arrangement that would reconfigure the Latrobe Valley network into parallel mode and attempt to reduce loading on the 500 kV network by redirecting flows onto the 220 kV corridor. The 2025 VAPR<sup>65</sup> noted works were progressing with relevant asset owners to enable transition to modified parallel operating mode when Yallourn retires. The Latrobe Valley modified parallel configuration will continue to utilise the Yallourn Power Station switchyard (YPS) connections to Hazelwood Power Stations switchyard (HWPS) to enable the 220 kV lines connected to both switchyards to continue to supply consumers.

Yallourn retirement places a greater reliance on renewable generation to support demand in Victoria. A majority of renewable generation is in Western Victoria and as such highlights the need for additional thermal capacity in Western Victoria as confirmed by the 2025 NSCAS studies.

The 2025 NSCAS studies identified that by 2030-31:

- While the reconfiguration is effective in the short term following Yallourn retirement, the gap is expected to re-emerge (due to limitations on 500/220 kV transformers) as maximum demand continues to grow and additional generators retire in the Latrobe Valley.
- Thermal overloads are present following a credible contingency, related to supporting Deer Park demand, on the Deer Park – Geelong, Deer Park – Keilor, and Geelong – Keilor 220 kV lines.
- Thermal overloads are present following a credible contingency, related to supporting demand, on the Moorabool – Geelong, Keilor – Thomastown, Rowville – Malvern, Moorabool – Terang, Ringwood – Thomastown and Thomastown – Templestowe 220 kV lines.
- Thermal overloads are present following a credible contingency in Western Victoria, related to export of renewable generation out of the area, on the Red Cliffs – Wemen – Koorangie, Koorangie – Kerang and Ballarat-Bendigo 220 kV lines.
- Under a scenario with Basslink out of service and committed transmission, generation and storage developments considered, maintaining sufficient supply to Victorian peak demand is challenging in 2030-31.

<sup>63</sup> See <https://www.aemo.com.au/-/media/files/initiatives/metropolitan-melbourne-voltage-management-rit/melbourne-metropolitan-voltage-management-project-assessment-draft-report.pdf?la=en>.

<sup>64</sup> At [https://wa.aemo.com.au/-/media/files/electricity/nem/planning\\_and\\_forecasting/vapr/2023/2023-victorian-annual-planning-report.pdf?la=en](https://wa.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2023/2023-victorian-annual-planning-report.pdf?la=en).

<sup>65</sup> At [https://www.aemo.com.au/-/media/files/electricity/nem/planning\\_and\\_forecasting/vapr/2025/2025-victorian-annual-planning-report.pdf?rev=170d75d5022a4fa8842c0010e3cacc0e&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2025/2025-victorian-annual-planning-report.pdf?rev=170d75d5022a4fa8842c0010e3cacc0e&sc_lang=en).

VicGrid is progressing investment testing for Eastern Victoria Grid Reinforcement<sup>66</sup> and Western Metropolitan Melbourne Reinforcement<sup>67</sup>. These aim to address grid reinforcement needs, including those identified in the 2025 NSCAS studies, following retirement of coal generation and increase to demand. Additionally, Western Renewables Link<sup>68</sup> will improve thermal capability in this region. AEMO will continue to monitor remediation of this issue based on assessment of progress in a future NSCAS report.

### A2.6.3.2 Rapid voltage change

AEMO assessed the expected voltage change impacts of switching reactive plant in Victoria<sup>69</sup>. **Table 98** summarises the results of this analysis indicating maximum voltage deviations for a given case, the appropriate IEC Standard<sup>70</sup>, and whether that standard is met. The results demonstrate that the standard is met for all conditions assessed.

**Table 98 Rapid voltage change results for reactive plant switching in Victoria**

Case	Project assumptions	Year of assessment	Maximum voltage step (%)	Bus with maximum voltage step	Switched reactive plant	IEC Standard	Does it meet the standard?
Maximum demand day	Committed Projects Only	2025 -26	2.52%	Altona 220 kV bus	200 MVar capacitor at Altona 220 kV bus	3%-5%	Yes
	Committed Projects Only	2030 -31	3.54%	Altona 220 kV bus	200 MVar capacitor at Altona 220 kV bus		Yes
	Committed Projects Only	2030 -31	3.28%	Brooklyn 220 kV bus	200 MVar capacitor at Brooklyn 220 kV bus		Yes
	Committed Projects Only	2030 -31	2.87%	Fishermans Bend 220 kV bus	200 MVar capacitor at Fishermans Bend 220 kV bus		Yes
	Committed Projects Only	2030 -31	2.73%	Keilor 220 kV bus	200 MVar capacitor at Keilor 220 kV bus		Yes

<sup>66</sup> At <https://aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf?la=en>.

<sup>67</sup> At <https://www.aemo.com.au/initiatives/major-programs/western-metropolitan-melbourne-reinforcement>.

<sup>68</sup> At <https://www.aemo.com.au/initiatives/major-programs/western-victorian-regulatory-investment-test-for-transmission>.

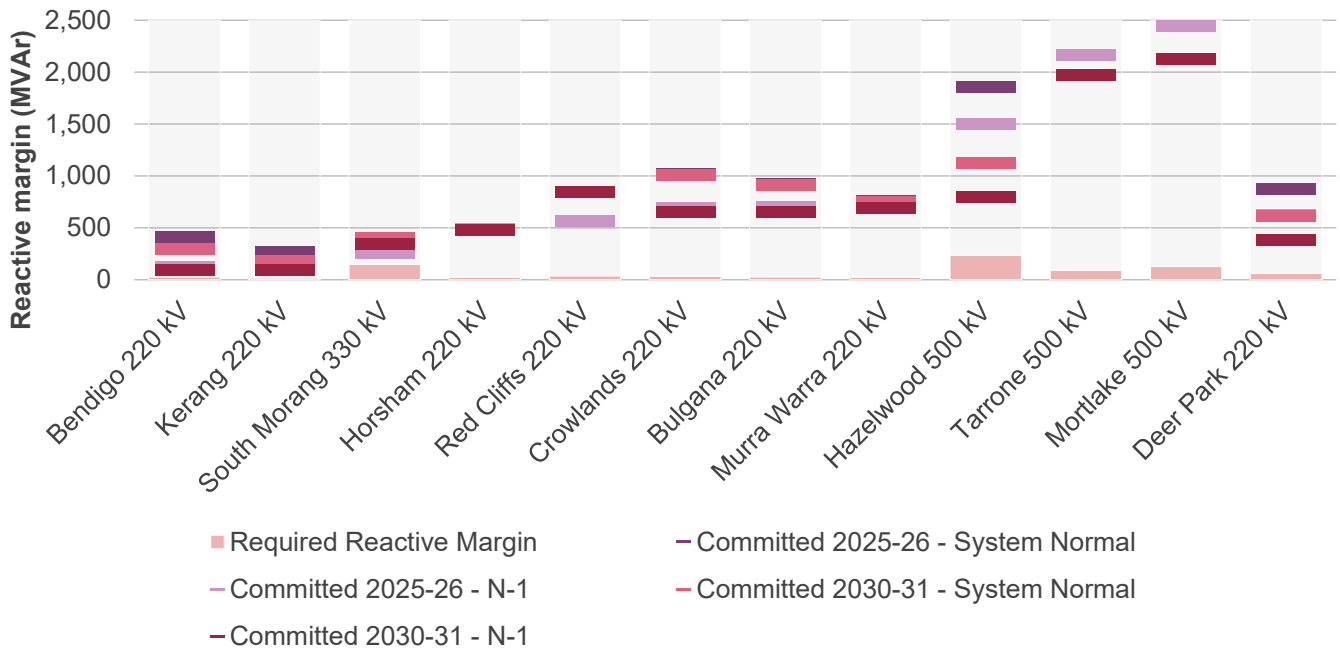
<sup>69</sup> Required reactive margin is defined by NER S5.1.8 as “not less than 1% of the maximum fault level (in MVA) at the connection point”. For the purposes of this assessment, the required reactive margin was calculated based on the 2023-24 maximum fault level.

<sup>70</sup> Requirements for voltage fluctuation are defined by NER S5.1a.5 and TR IEC 61000.3.7, Table 6, Indicative planning levels for rapid voltage changes as a function of the number of such changes in a given period. The number of voltage changes should not exceed four within a 24-hour period, with each change allowing a permissible variation of 3-5% for network elements operated at greater than 230 kV and 5-6% for network elements operated at voltages between 35 kV and 230 kV.

### A2.6.3.3 Reactive margin

AEMO assessed whether the system normal and post-contingent reactive margins at critical buses in Victoria are expected to remain above the system standard<sup>71</sup> of 1% of the local maximum fault level over the five-year outlook period. **Figure 59** summarises the results, which indicate that all reactive margins are projected to meet the standard. The results for 2030-31 were based on operating the Latrobe Valley in modified parallel mode<sup>72</sup>.

**Figure 59 Minimum reactive margin (MVar) observed for critical buses in Victoria**



### A2.6.3.4 System strength

AEMO modelled projected fault levels under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>73</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in section A2.8.2.

The expected three phase fault current at each system strength node in Victoria was compared against the latest minimum fault current requirements published in Section A2.6.2. In undertaking this assessment, AEMO conducted time sequential market modelling and detailed power system analysis to project the levels of fault current expected to be available for 99.87% of a typical year<sup>74</sup>.

<sup>71</sup> Required reactive margin is defined by NER S5.1.8 as “not less than 1% of the maximum fault level (in MVA) at the connection point”. For the purposes of this assessment, the required reactive margin was calculated based on the 2024-25 maximum fault level.

<sup>72</sup> See AEMO, 2025 VAPR, Figure 22, at [https://www.aemo.com.au/-/media/files/electricity/nem/planning\\_and\\_forecasting/vapr/2025/2025-victorian-annual-planning-report.pdf?rev=170d75d5022a4fa8842c0010e3cacc0e&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2025/2025-victorian-annual-planning-report.pdf?rev=170d75d5022a4fa8842c0010e3cacc0e&sc_lang=en).

<sup>73</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station ‘two-shifting’, and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

<sup>74</sup> 99.87% is equivalent to three standard deviations above the mean. See [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc\\_lang=en](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0.pdf?rev=79c63a4d0979453384d4ab16493f23da&sc_lang=en).

The results of this assessment are summarised in **Table 100**, and confirm that there are significant system strength deficits projected at Hazelwood and smaller deficits at Moorabool and Thomastown from 2028-29. This is predominantly due to retirement of Yallourn Power station from 2028-29<sup>75</sup>.

AEMO also modelled fault level projections under an outlook which included some parts of the preferred options from each TNSP's system strength RIT-T (RIT-T outlook) where modelling information was available or a reasonable assumption could be made. The remainder of the preferred option was not modelled due to uncertainty with contracting or confidentiality. Through joint planning with TNSPs, AEMO has used the latest available modelling information including the most up to date location, timing, inertia, and fault level contribution for synchronous condensers based on current procurement status, and services from non-network synchronous condensers and synchronous generation where a proponent has been identified. The parts of VicGrid's system strength RIT-T preferred solution modelled in the RIT-T outlook for fault level projections are detailed in Table 99 below.

**Table 99 Parts of VicGrid's System Strength RIT-T preferred option modelled in the RIT-T outlook for fault level projections**

System Strength Service Provider	Part of RIT-T preferred solution	Included in the RIT-T outlook for fault level projections?
VicGrid <sup>A</sup>	Five network synchronous condensers	Included.
	Non-network contracts with synchronous units	Contracting with one existing synchronous condenser at the Red Cliffs system strength node was included. No contracts with synchronous generation were included based on available information leading up to publication of this report. Contracts with synchronous generation are expected in the final portfolio of non-network contracts upon completion of tendering.
	Grid forming (GFM) BESS	Not included in fault level projections due to current lack of evidence that GFM BESS can provide protection quality fault current.

A. AVP, *Victorian System Strength Requirement Project Assessment Conclusions Report*, 2025, at <https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf>.

The modelled parts of the RIT-T solutions mostly address the deficits identified, with some interim deficits remaining in 2027-28, which could be managed via contracts with generators or similar.

**Table 100 Victoria fault level requirements and identified deficits against the requirements**

System strength node	Fault level requirement (MVA)	Identified deficit in the Modified ESOO scenario (MVA)					Identified deficit in the Modified ESOO scenario with modelled parts of the RIT-T solutions (MVA)				
		2025-26	2026-27	2027-28	2028-29	2029-30	2025-26	2026-27	2027-28	2028-29	2029-30
Dederang 220 kV	3,500	0	0	0	0	0	0	0	0	0	0
Hazelwood 500 kV	7,700	384	0	562	2,031	1,999	107	0	348	0	0
Moorabool 220 kV	4,600	0	0	0	558	654	0	0	0	0	0
Red Cliffs 220 kV	1,786	0	5	0	0	0	0	0	0	0	0
Thomastown 220 kV	4,700	0	0	0	650	661	0	0	0	0	0

<sup>75</sup> AEMO received a notice of closure for Yallourn Power Station stating intention for all units to cease supplying, acquiring, or trading in the market from 1 July 2028.



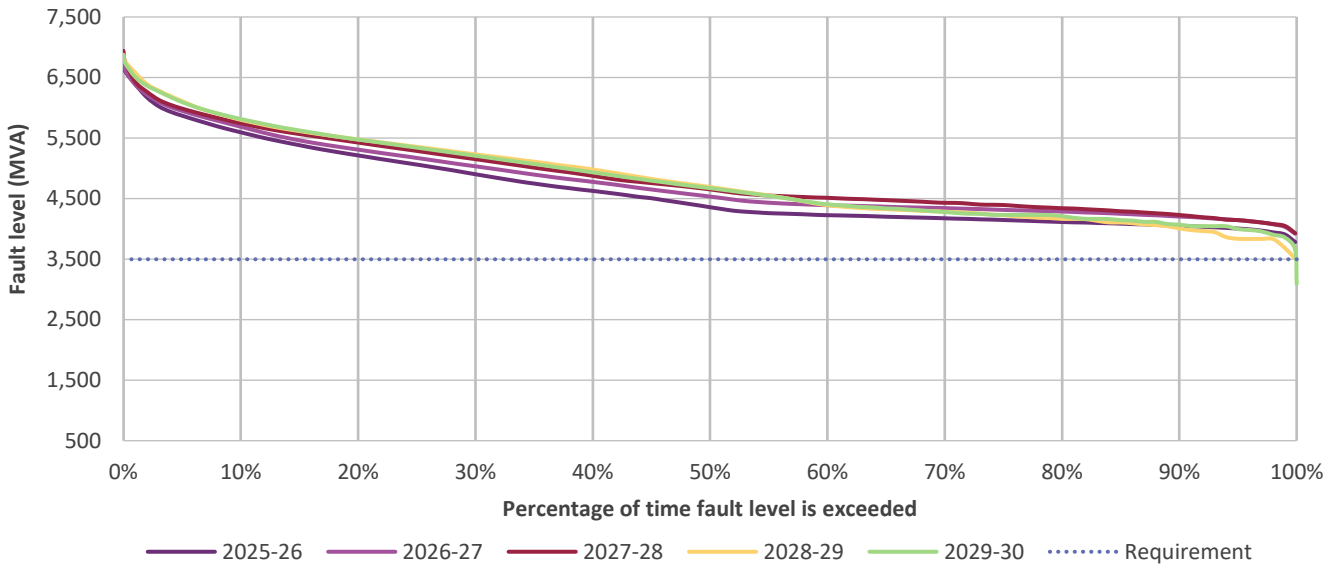
Section A2.6.2 provides additional detail on the calculation of fault level requirements. Detailed projected fault levels per system strength node are shown below with and without modelled parts of the RIT-T solutions. The results assumed that one Hazelwood to South Morang 500 kV line is out of service for voltage control during low demand until 2028-29 when the preferred option reactors from the Victorian metro voltage management RIT-T<sup>76</sup> are delivered.

### Dederang 220 kV

**Figure 60** shows the projected three phase fault level at the Dederang 220 kV node without the modelled parts of the RIT-T solution. Dederang does not show any deficits in the modelling horizon. **Figure 61** shows an increase in the projected fault levels after implementing the modelled parts of the RIT-T solutions.

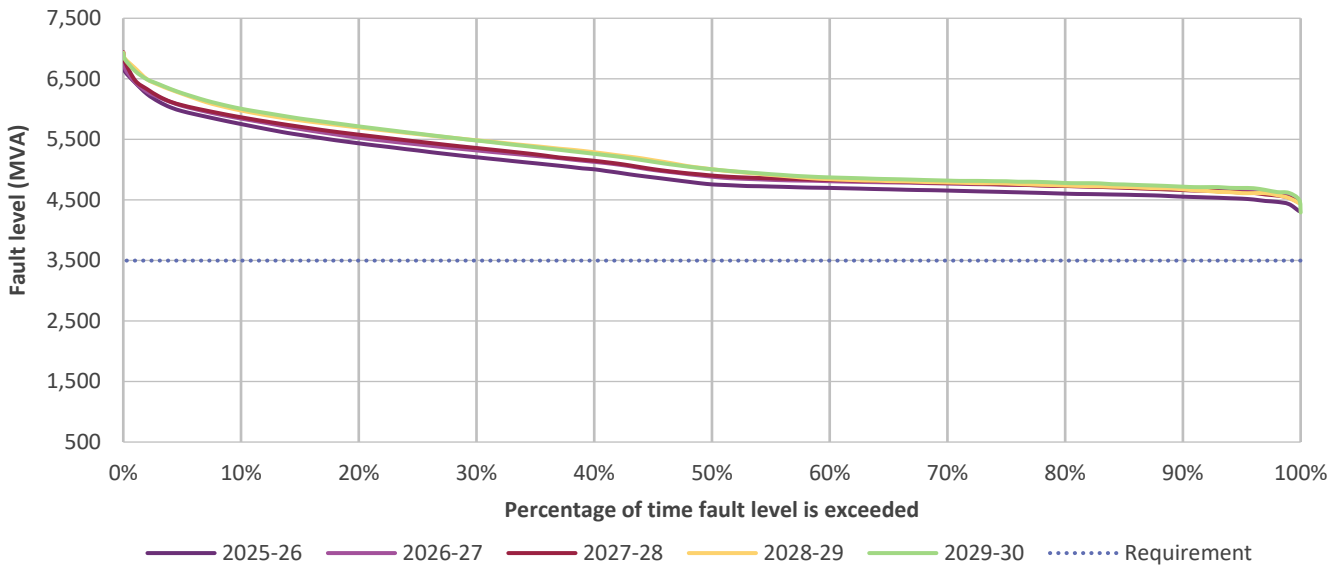
**Table 101** shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The increase in fault level at Dederang is primarily due to nearby parts of the RIT-T solutions to manage fault levels at neighbouring system strength nodes.

**Figure 60 Dederang node fault level duration curves and minimum requirement**



<sup>76</sup> At <https://www.aemo.com.au/-/media/files/initiatives/metropolitan-melbourne-voltage-management-rit/metropolitan-melbourne-voltage-management-pacr.pdf>.

**Figure 61 Dederang node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 101 Dederang node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Dederang 220 kV	Minimum fault level requirement (MVA)	3,500	3,500	3,500	3,500	3,500
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	3,783	3,921	3,931	3,510	3,655
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	4,313	4,459	4,456	4,445	4,502
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

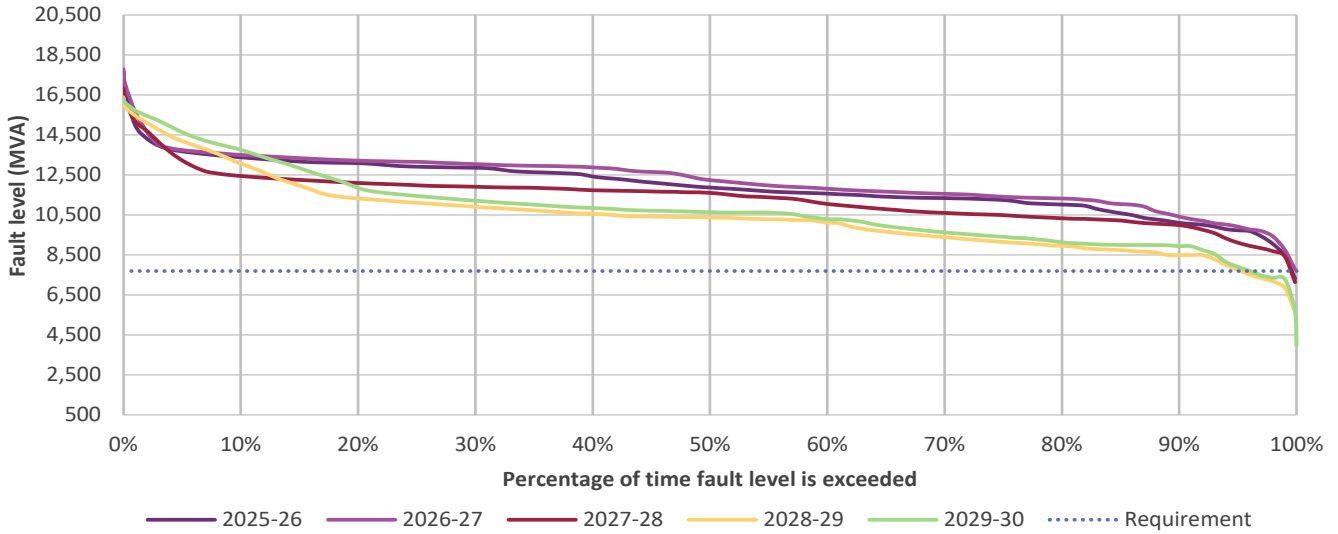
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Hazelwood 500 kV

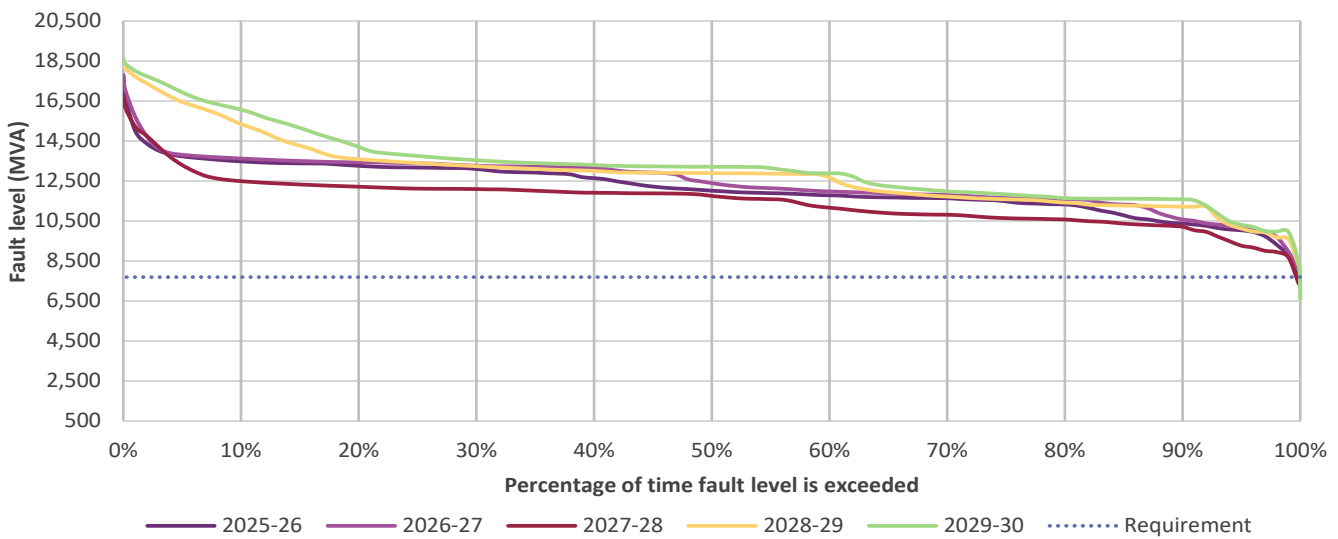
Figure 62 shows the projected three phase fault level at the Hazelwood 500 kV node without the modelled parts of the RIT-T solution. Hazelwood sees a deficit in 2025-26, 2027-28, 2028-29 and 2029-30. Figure 63 shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which reduces the deficit seen in 2025-26 and 2027-28 while removing the deficit seen in 2028-29 and 2029-30.

Table 102 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The larger deficits from 2028-29 are largely due to retirement of Yallourn Power station. These larger deficits from 2028-29 are addressed by the modelled parts of the RIT-T solutions, with some remaining interim deficits in 2025-26 and 2027-28. VicGrid is currently tendering for synchronous unit contracts for system strength, which were not included in this modelling and which may address the remaining deficit.

**Figure 62 Hazelwood node fault level duration curves and minimum requirement**



**Figure 63 Hazelwood node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 102 Hazelwood node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Hazelwood 500 kV	Minimum fault level requirement (MVA)	7,700	7,700	7,700	7,700	7,700
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	7,316	7,764	7,138	5,669	5,701
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	7,593	8,047	7,352	8,260	8,296
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	384	0	562	2,031	1,999
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	107	0	348	0	0
	NSCAS gap (Yes/No)*		No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

Moorabool 220 kV

Figure 64 shows the projected three phase fault level at the Moorabool 220 kV node without the modelled parts of the RIT-T solution. Moorabool sees a deficit in 2028-29 and 2029-30. Figure 65 shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the previously seen deficits.

Table 103 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The deficits at Moorabool from 2028-29 are largely due to retirement of Yallourn Power Station. These deficits are addressed by the delivery of the modelled parts of the RIT-T solutions, on time and in full.

Figure 64 Moorabool node fault level duration curves and minimum requirement

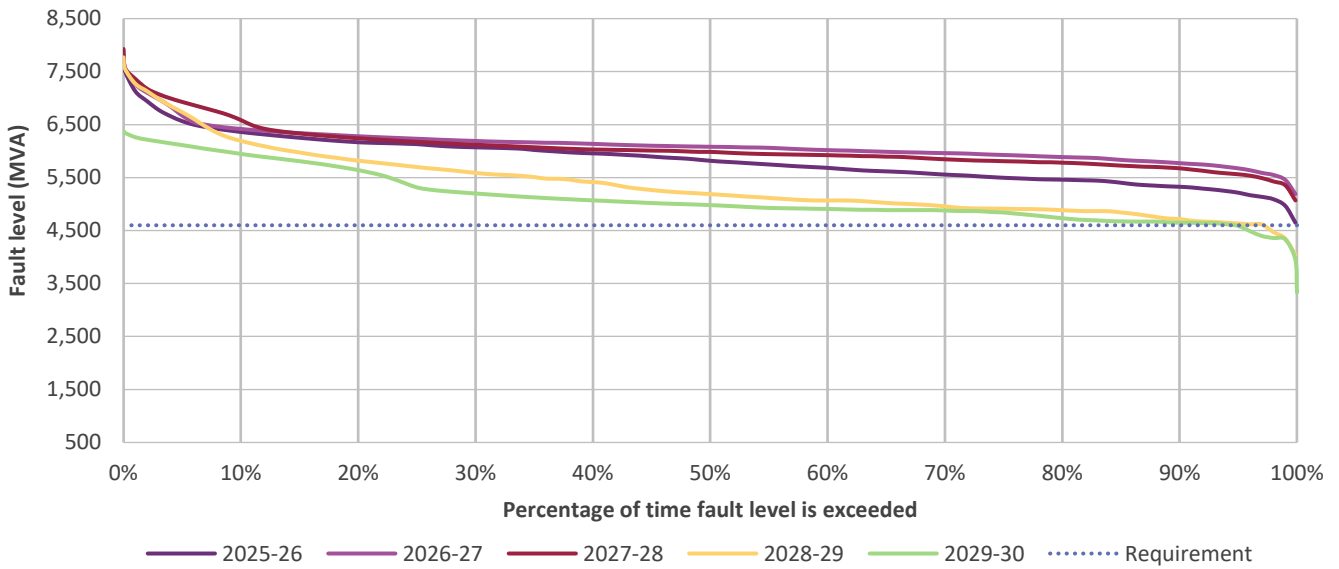
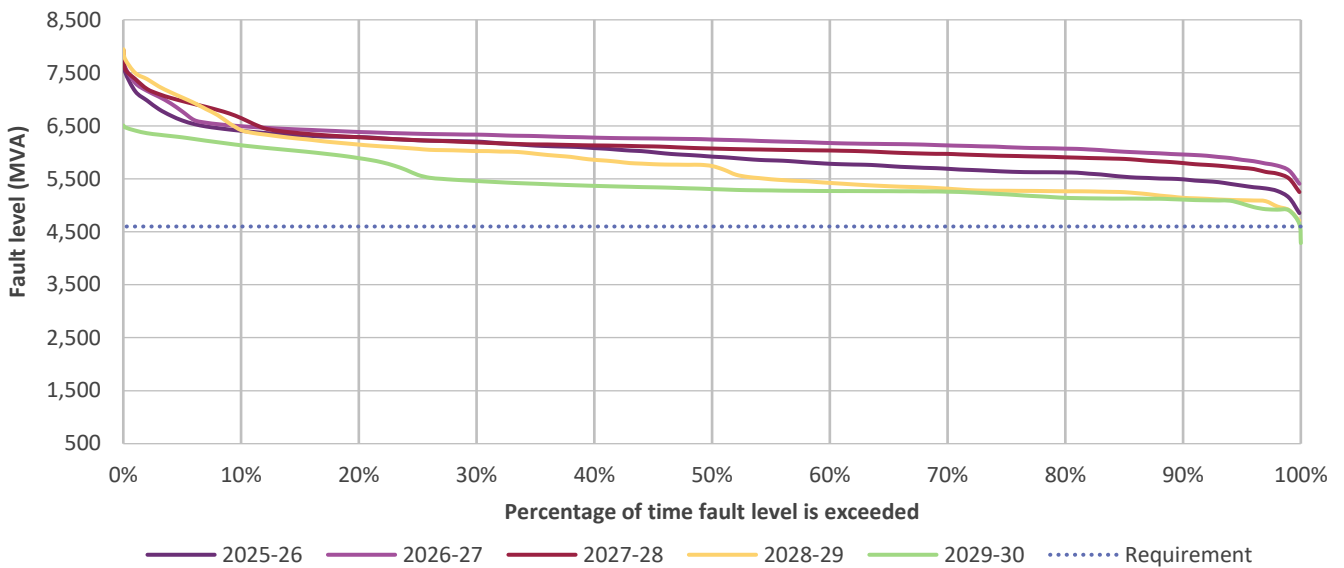


Figure 65 Moorabool node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution



**Table 103 Moorabool node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Moorabool 220 kV	Minimum fault level requirement (MVA)	4,600	4,600	4,600	4,600	4,600
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	4,649	5,187	5,071	4,042	3,946
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	4,855	5,407	5,247	4,705	4,650
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	558	654
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

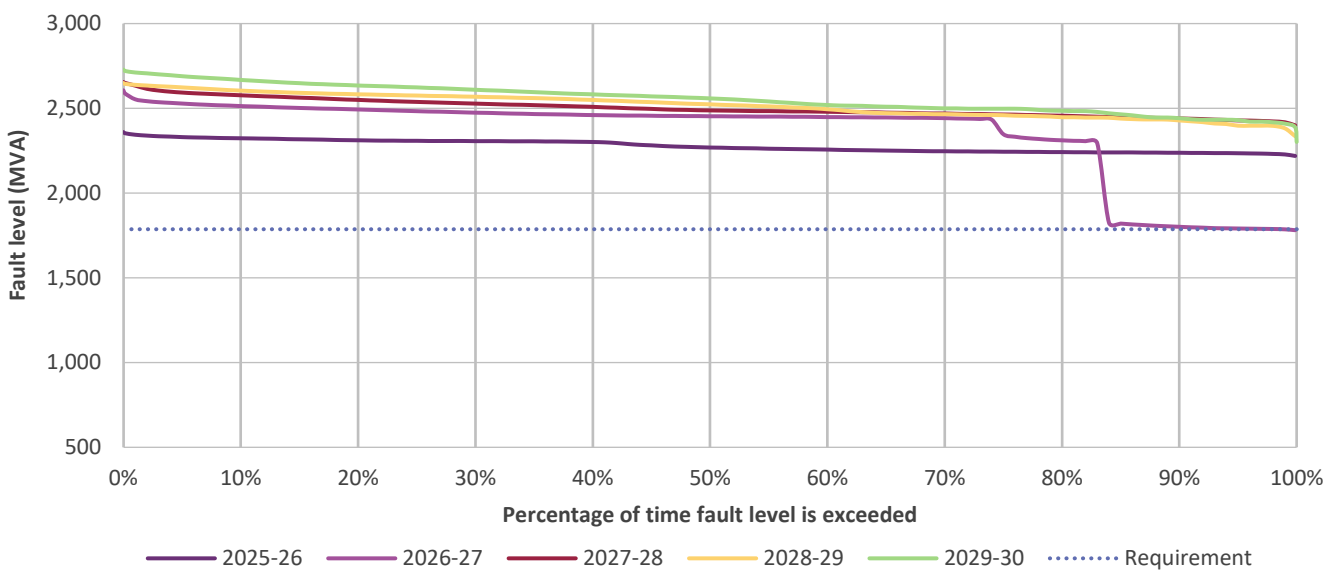
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Red Cliffs 220 kV

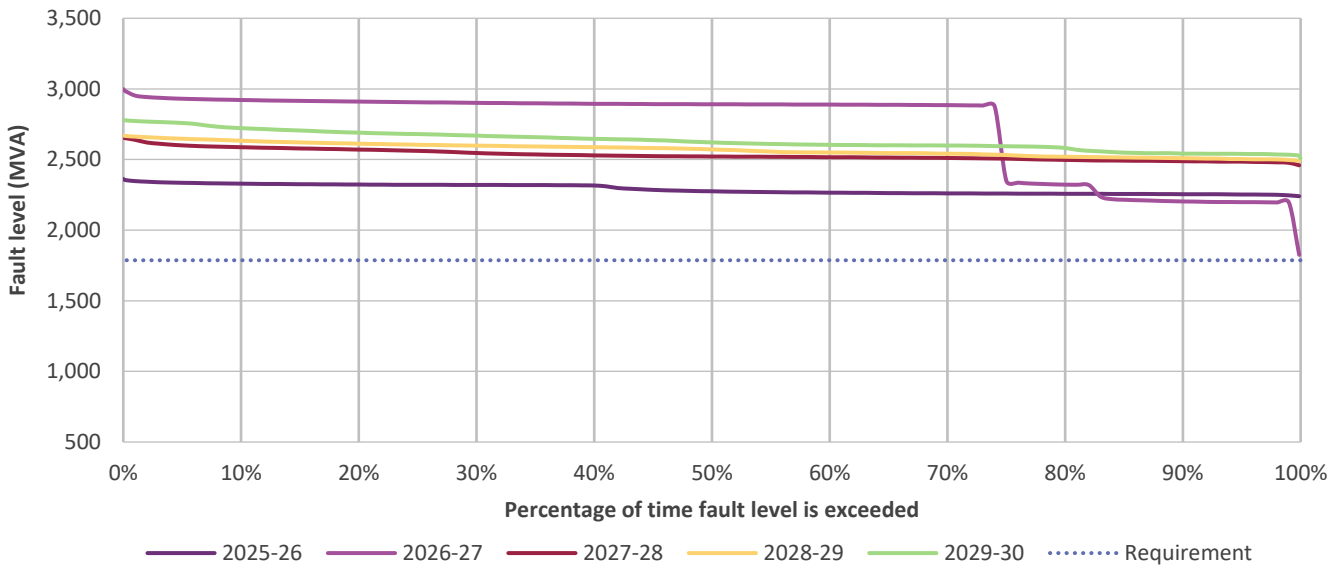
Figure 66 shows the projected three phase fault level at the Red Cliffs 220 kV node without the modelled parts of the RIT-T solution. Red Cliffs does not show any deficits in the modelling horizon. Figure 67 shows an increase in the projected fault levels after implementing the modelled parts of the RIT-T solutions.

Table 104 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. VicGrid has existing contracts in place for system strength with existing synchronous condensers near the Red Cliffs node which expire in July 2026. A small interim deficit is seen at Red Cliffs in 2026-27 following the expiry of these contracts. This deficit is addressed from 2027-28 by commissioning of synchronous condensers at Dinawan under Project EnergyConnect. The interim deficit in 2026-27 is addressed by the modelled parts of the RIT-T solutions, which includes new contracts with existing synchronous condensers near the Red Cliffs node.

**Figure 66 Red Cliffs node fault level duration curves and minimum requirement**



**Figure 67 Red Cliffs node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 104 Red Cliffs node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Red Cliffs 220 kV	Minimum fault level requirement (MVA)	1,786	1,786	1,786	1,786	1,786
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	2,219	1,781	2,400	2,336	2,389
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	2,240	1,825	2,460	2,490	2,528
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	5	0	0	0
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

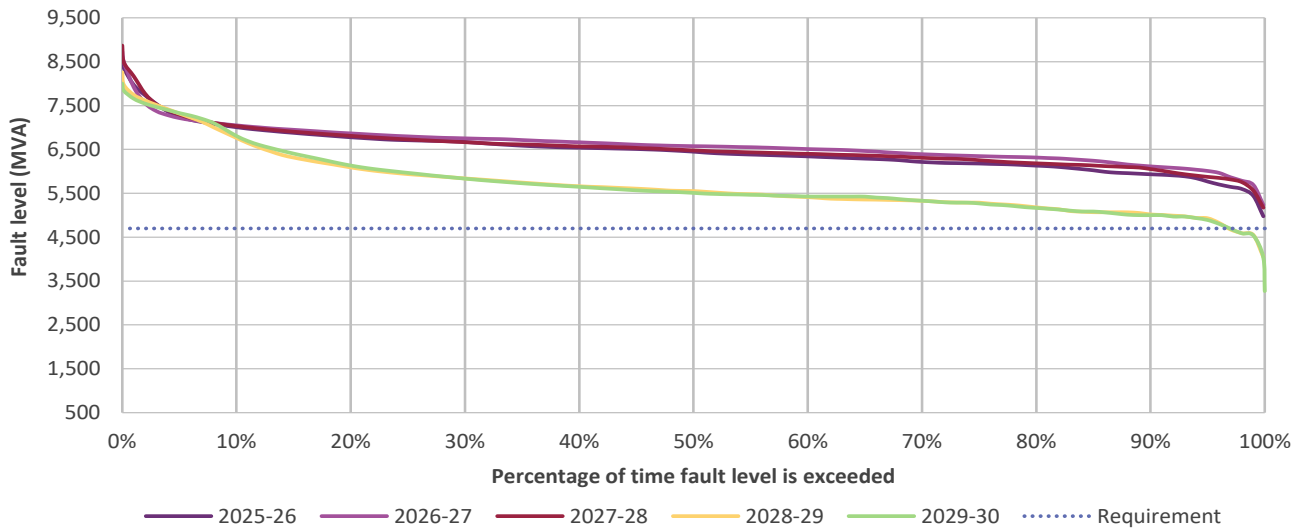
\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### Thomastown 220 kV

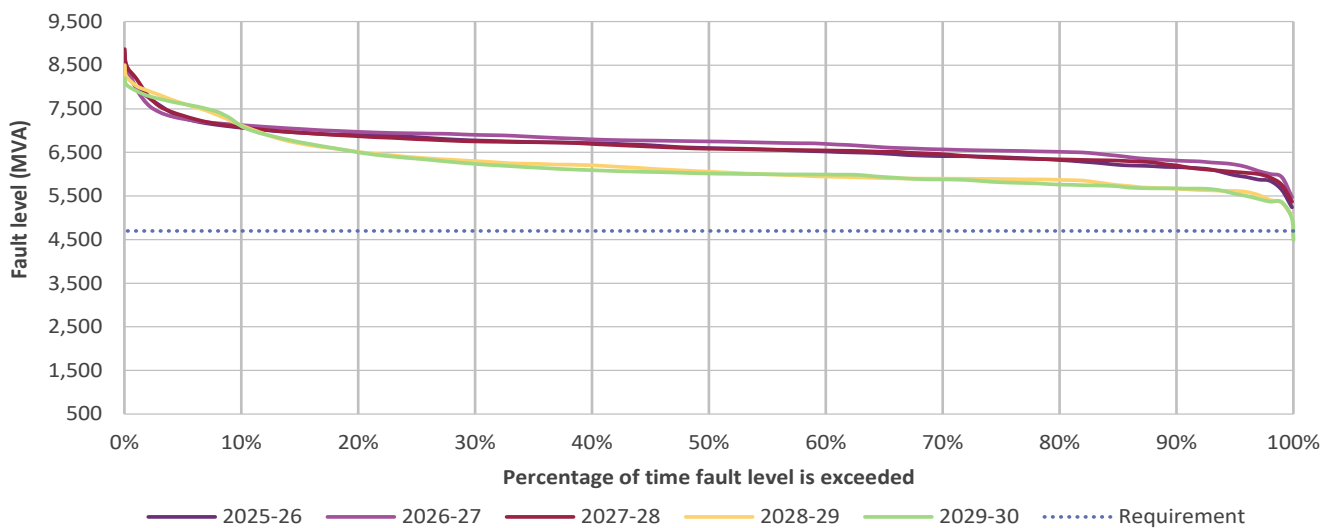
Figure 68 shows the projected three phase fault level at the Thomastown 220 kV node without the modelled parts of the RIT-T solution. Thomastown sees a deficit in 2028-29 and 2029-30. Figure 69 shows the projected fault levels after implementing the modelled parts of the RIT-T solutions, which removes the previously seen deficits.

Table 105 shows the summarised results for the 99.87<sup>th</sup> percentile values from these figures. The deficits at Thomastown from 2028-29 are largely due to retirement of Yallourn Power station. These deficits are addressed by delivery of the modelled parts of the RIT-T solutions, on time and in full.

**Figure 68 Thomastown node fault level duration curves and minimum requirement**



**Figure 69 Thomastown node fault level duration curves and minimum requirement with modelled parts of the RIT-T solution**



**Table 105 Thomastown node projected 99.87% three phase fault level with and without modelled parts of the RIT-T solution**

Node	Quantity	2025-26	2026-27	2027-28	2028-29	2029-30
Thomastown 220 kV	Minimum fault level requirement (MVA)	4,700	4,700	4,700	4,700	4,700
	Projected fault level 99.87% of time without modelled parts of RIT-T preferred option (MVA)	4,978	5,235	5,172	4,050	4,039
	Projected fault level 99.87% of time with modelled parts of RIT-T preferred option (MVA)	5,239	5,471	5,370	5,052	4,992
	System strength deficit without modelled parts of RIT-T preferred option (MVA)	0	0	0	650	661
	System strength deficit with modelled parts of RIT-T preferred option (MVA)	0	0	0	0	0
	NSCAS gap (Yes/No)*	No	No	No	No	No

\*NSCAS gaps cannot be declared because the minimum fault level requirement has not been revised.

### A2.6.3.5 Inertia

AEMO modelled projected inertia under two development outlooks:

- 2025 ESOO *Government Schemes and Actionable Developments* scenario<sup>77</sup>, modified with 2024 ISP retirements and latest Queensland and South Australia notifications of closure (Modified ESOO scenario), and
- Modified ESOO scenario, with implementation of the modelled parts of the System Strength RIT-T preferred options, as described in section A2.8.2.

AEMO assessed the expected levels of available inertia in Victoria against the latest *inertia requirements* published in Section A2.6.1. The assessment considered the Victoria portion of the *system-wide inertia level*, the islanded regional requirements, and the likelihood of the region becoming islanded.

As part of that assessment, AEMO deemed Victoria unlikely to become islanded<sup>78</sup> given its strong interconnection with neighbouring regions. Consequently, AEMO's analysis focused on potential deficits relative to Victoria's allocation of the *system-wide inertia level* (the *inertia sub-network allocation*).

#### System-wide inertia level assessment for Victoria

**Figure 70** and **Table 107** show the projected inertia levels for the Victoria region in the modified ESOO scenario. Under typical operation, available inertia is expected to fall below the sub network allocation in financial year 2025-26 through to the end of the projection horizon 2029-30.

AEMO also modelled inertia projections under an outlook which included some parts of the preferred options from each TNSP's system strength RIT-T (RIT-T outlook) where modelling information was available or a reasonable assumption could be made. The remainder of the preferred option was not modelled due to uncertainty with contracting or confidentiality. Through joint planning with TNSPs, AEMO has used the latest available modelling information including the most up to date location, timing, inertia, and fault level contribution for synchronous condensers based on current procurement status, and services from non-network synchronous condensers and synchronous generation where a proponent has been identified. The parts of the system strength RIT-T preferred solution modelled in the RIT-T outlook for inertia projections are detailed in **0** below.

<sup>77</sup> Modified to contain 2024 ISP generation retirements, Bayswater Power Station 'two-shifting', and the Gladstone Power Station notification. See <https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station>.

<sup>78</sup> Historically, AEMO has assessed a scenario where the NEM has separated with Victoria and South Australia forming an island. For completeness, AEMO has confirmed that no inertia deficit exists for this scenario with updated inputs in 2024, however AEMO considers that the *system-wide inertia level* requirement assessment should supersede the need for this scenario in future.

**Table 106** Parts of VicGrid’s System Strength RIT-T preferred option modelled in the RIT-T outlook for inertia projections

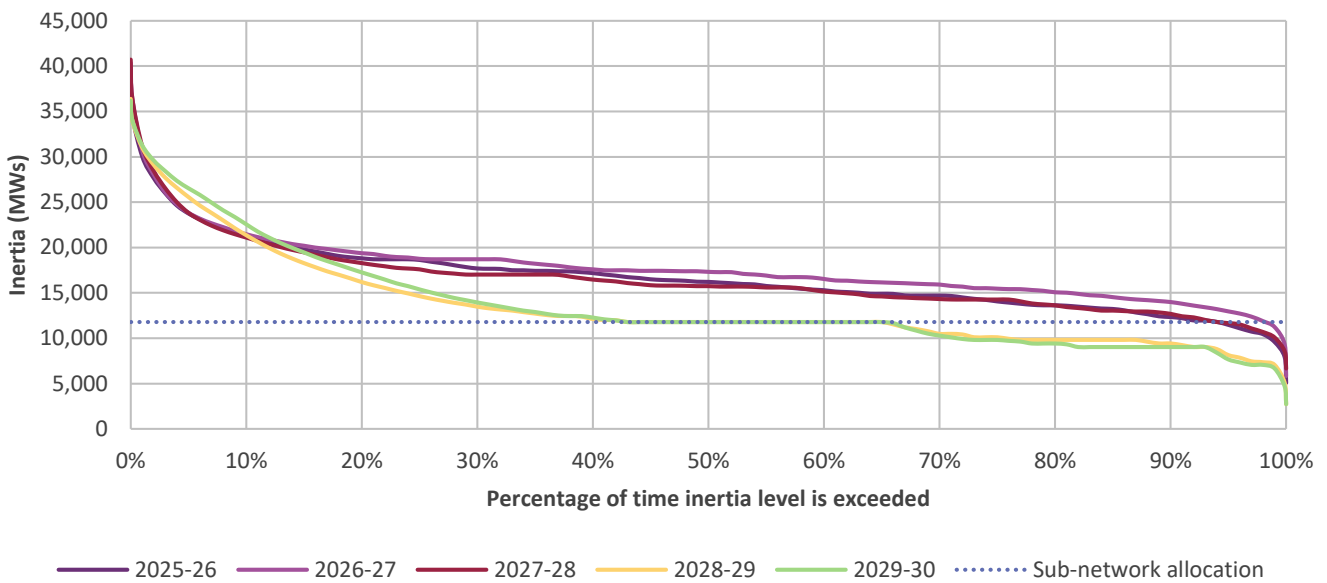
System Strength Service Provider	Part of RIT-T preferred solution	Included in the RIT-T outlook for inertia projections?
VicGrid <sup>A</sup>	Five network synchronous condensers	Included.
	Non-network contracts with synchronous units	Contracting with one existing synchronous condenser at the Red Cliffs system strength node was included. No contracts with synchronous generation were included based on available information leading up to publication of this report. Contracts with synchronous generation are expected in the final portfolio of non-network contracts upon completion of tendering.
	Grid forming (GFM) BESS	Not included in inertia projections as synthetic inertia constants have not been calculated.

A. AVP, *Victorian System Strength Requirement Project Assessment Conclusions Report*, 2025, at <https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf>.

The modelled parts of the RIT-T solutions reduce the inertia deficits, but large 2,143-3,873 MVA deficits remain. This residual risk could be managed via contracts with synchronous generators or similar.

VicGrid must ensure that its full *inertia sub-network allocation* of 11,800 MWs is met from 2 December 2027.

**Figure 70** Projected inertia for the five-year outlook, Modified ESOO scenario, Victoria



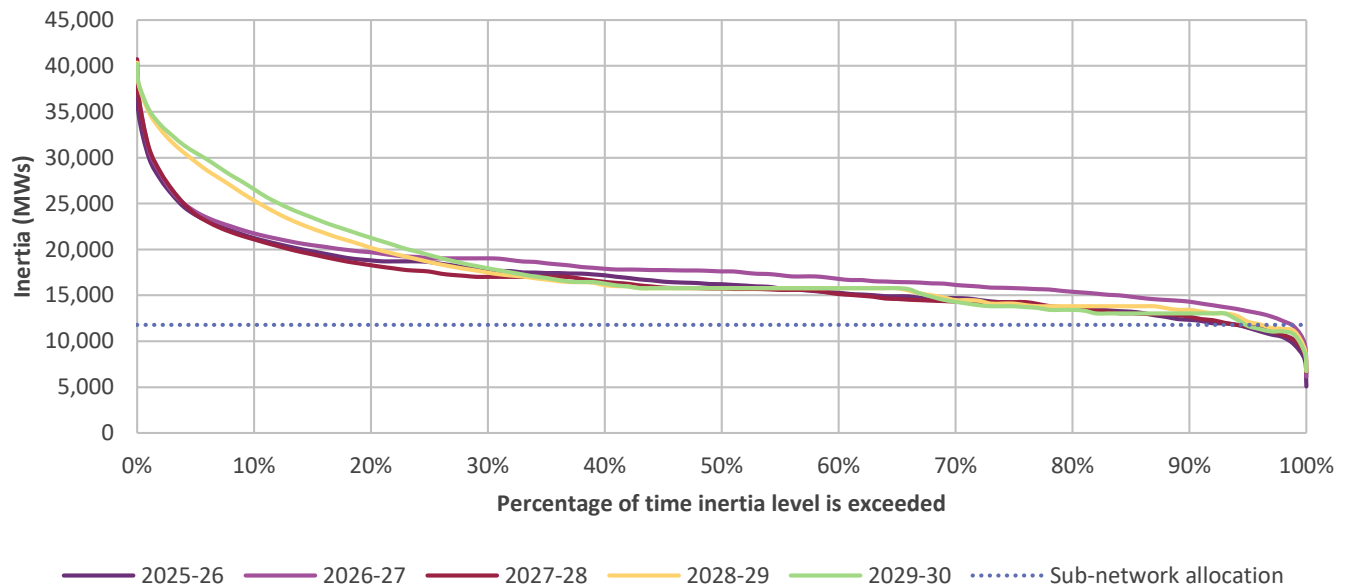
**Table 107** Inertia sub-network allocation and projections, Modified ESOO scenario, Victoria

	2025-26	2026-27	2027-28	2028-29	2029-30
Inertia sub-network allocation (MWs)	11,800	11,800	11,800	11,800	11,800
Available inertia 99.87% of the time (MWs)	7,927	9,312	8,565	5,091	4,696
Inertia deficit (MWs)	3,873	2,488	3,235	6,709	7,104
NSCAS gap (Yes/No)*	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.

\*NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

**Figure 71** Projected inertia for the five-year outlook, Modified ESOO scenario with modelled parts of the RIT-T solution, Victoria



**Table 108** Inertia sub-network allocation and projections, Modified ESOO scenario with modelled parts of the RIT-T solution, Victoria

	2025-26	2026-27	2027-28	2028-29	2029-30
<b>Inertia sub-network allocation (MWs)</b>	11,800	11,800	11,800	11,800	11,800
<b>Available inertia 99.87% of the time (MWs)</b>	7,927	9,657	8,565	9,091	8,696
<b>Inertia deficit (MWs)*</b>	3,873	2,143	3,235	2,709	3,104
<b>NSCAS gap (Yes/No)^</b>	No	No	No	No	No

Note: Modelling was conducted on a financial year basis, however the gap declaration period is from 2 December 2025 to 1 December 2028.  
 \*The 7,927 MWs deficit in 2025-26 does not incorporate synthetic inertia from the GFM BESS which would make the available inertia greater than the minimum regional interconnected level of 8000 MWs.  
 ^NSCAS gaps for inertia can only be declared when the deficit occurs within the next three years and is caused by an increase in the minimum inertia requirement.

### A2.6.3.6 Market benefits ancillary services assessment

AEMO has not identified any new MBAS gaps in Victoria. **Table 109** provides a comparison of binding hours and marginal values for the top impact constraints in Victoria<sup>79</sup>. All constraints with a marginal value exceeding \$60,000 per year have previously been considered by VicGrid. In each case, a risk status, project, control scheme, or other mitigation strategy has been identified. These options are being monitored through the annual VAPR process and may trigger action if market benefits exceed remediation costs.

<sup>79</sup> Marginal values have been used as a proxy for the relative impact of constraints; however, this is not equivalent to the market benefits of relieving the constraint. More information on this metric is in the NSCAS Description and Quantity Procedure, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/system\\_security\\_planning/nscas-description-and-quantity-procedure-v3-0](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/nscas-description-and-quantity-procedure-v3-0).

Table 109 Victorian high-impact constraint summary for 2024 calendar year

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
V^AV_NIL_KGTSxx	Out= Nil, avoid voltage collapse for loss of Horsham - Murra Warra - Kiamal 220kV line. Murraylink VFRB disabled. Swamp if Murraylink VFRB enabled.	12.3M (↑\$4.1M)	1,473.1	Project EnergyConnect, Ararat Syncon and the connection of Koorangie Energy Storage System are expected to reduce the impact of these constraints. Expected planned completion date is 2027-28.
V>>NIL_WBBA_KGBE	Out= Nil, avoid O/L Waubra to Ballarat 220kV line on trip of Kerang to Bendigo 220kV line, Feedback	1.4M (↑\$0.3M)	163.5	It is expected that minor augmentations as part of the Victorian Government's RDP Stage 1 projects and the WRL project increase the thermal capability of the Ballarat – Waubra– Ararat – Crowlands – Bulgana – Horsham– Murra Warra – Kiamal 220 kV corridor to reduce the impact of this limitation. Expected planned completion date is 2029-30.
V>>NIL_ELML_BAML2	Out= Nil, avoid O/L Elaine to Moorabool 220kV line on trip of Ballarat to Moorabool No.2 220kV line, Feedback	0.7M (↑\$0.6M)	222.2	The WRL project will reduce the impact of this constraint. Expected planned completion date is 2029-30.
V^ASML_NIL_3	Out = Nil, avoid voltage collapse for loss of Bendigo to Kerang 220kV line	0.4M (↑\$0.1M)	85.0	Project EnergyConnect, Ararat Syncon and the connection of Koorangie Energy Storage System are expected to reduce the impact of these constraints. Expected planned completion date is 2027-28.
V>>NIL_WBBA_RCWEKG	Out = Nil, avoid O/L Waubra to Ballarat 220kV line on trip of Red Cliffs to Wemen to Koorangie 220kV line (this trips off Bannerton and Wemen solar farms), Feedback	0.3M (↓\$0.3M)	131.3	It is expected that minor augmentations as part of the Victorian Government's RDP Stage 1 projects and the WRL project increase the thermal capability of the Ballarat – Waubra– Ararat – Crowlands – Bulgana – Horsham– Murra Warra – Kiamal 220 kV corridor to reduce the impact of this limitation. Expected planned completion date is 2029-30.
V^AN_NIL_1	Out = Nil, avoid voltage collapse around Murray for loss of all APD potlines	0.3M (↓\$0.2M)	329.1	VicGrid is investigating the possible causes of APD tripping due to failure to ride through 500 kV faults and is exploring options to avoid tripping. Completion of Project EnergyConnect Stage 2, WRL and VNI West is expected to reduce the impact of this constraint. Expected planned completion date is 2029-30.
V^ASML_NSWRB_2	Out = NSW Murraylink runback scheme, VIC to SA transfer limit on Murraylink to avoid voltage collapse at Red Cliffs for the loss of either the Darlington Point to Balranald (X5) or Balranald to Buronga (X3) 220kV lines	0.2M (↑\$0.1M)	20.7	Project EnergyConnect, Ararat Syncon and the connection of Koorangie Energy Storage System are expected to reduce the impact of these constraints. Expected planned completion date is 2027-28. Note this constraint is only expected to be in service during unavailability of the Murraylink runback scheme.
V>NIL_WBBA_KMRC	Out= Nil, avoid O/L Waubra to Ballarat 220kV line on trip of Kiamal to Red Cliffs 220kV line, Feedback. Constraint active only when GFT2 on Murra Warra WF I/S.	0.2M (↑\$0M)	25.0	It is expected that minor augmentations as part of the Victorian Government's RDP Stage 1 projects and the WRL project increase the thermal capability of the Ballarat – Waubra– Ararat –

Constraint ID	Description	Marginal value (↓↑ change)	Binding hours	TNSP comments
				Crowlands – Bulgana – Horsham– Murra Warra – Kiamal 220 kV corridor to reduce the impact of this limitation. Expected planned completion date is 2029-30.
V^^V_NIL_SWVIC	Out = Nil, manage flow towards Moorabool across Haunted Gully to Cressy and Mortlake to Cressy 500kV lines to avoid voltage instability for the loss of Haunted Gully to Cressy 500kV line and both APD potlines	0.2M (↑\$0.1M)	192.9	Mortlake Power Station (MOPS) turn-in project, as a part of the Victorian Government's RDP and the new terminal station at Cressy <sup>A</sup> , will reduce the impact of this constraint. This project was completed in July 2025.
V>>NIL_BABE_HOMRKM	Out= Nil, avoid O/L Ballarat to Bendigo 220kV line on trip of Horsham to Murra Warra to Kiamal 220kV line (this trips Murra Warra WF), Feedback	0.1M (↓\$0.1M)	40.5	The WRL project will reduce the impact of this constraint. Expected planned completion date is 2029-30.

Note: From annual NEM Constraint Report, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/statistical-reporting-streams>. Constraints have been prioritised as per calendar year 2024 data A. See <http://www.gazette.vic.gov.au/gazette/Gazettes2022/GG2022S547.pdf>.

## A2.7 Inertia levels for interconnected operation

Inertia is not a purely global quantity across the NEM. The effectiveness of inertia in one region to provide frequency support in another region is highly sensitive to network topology, the nature of supply and demand along the corridor between the regions, intervening network limitations, and a range of other system conditions in effect during frequency disturbance events. For example, if no inertia was online in Queensland, the FOS would not be met following a credible contingency event in Queensland, no matter how much inertia is online in other regions.

AEMO has calculated minimum regional interconnected inertia levels for each mainland NEM region to quantify inertia sharing when interconnected. When every mainland region individually is above its minimum regional interconnected inertia level and the total mainland inertia is above the system-wide inertia level, inertia can be shared freely between regions. The minimum regional interconnected inertia levels are not part of the formal inertia requirements and are each less than or equal to the subnetwork allocation for the region.

To calculate the minimum regional interconnected inertia levels, AEMO performed PSS®E dynamics simulations of a credible contingency under low inertia levels to assess whether the FOS was met. For each region, the most onerous contingency was identified and simulated under progressively lower levels of inertia in that region. As inertia was lowered in the region of study, inertia was increased in other regions to keep the total system inertia at the system-wide inertia level. The minimum regional interconnected inertia level was set at the highest level of inertia that resulted in a marginal pass.

The minimum regional interconnected inertia levels and sub-network allocations for each region are summarised in **Table 110** below.

**Table 110 Minimum regional interconnected inertia level and sub-network allocation per region**

Region	Minimum regional interconnected inertia level (MWs)	Inertia sub-network allocation (MWs)
New South Wales	7,500	9,600
Queensland	10,500	10,500
South Australia	1,800	4,300
Victoria	8,000	11,800

Note: The system-wide level of inertia requirement only applies to mainland NEM regions, so Tasmania is not included in this table.

The application of each component of the *inertia requirements* and the minimum regional interconnected inertia levels are summarised in **Table 111** below.

**Table 111 Application of inertia requirements terms**

Concept	Required to maintain the FOS following a credible contingency	Sets a requirement for TNSPs to procure inertia services	Operational conditions under which it applies
Minimum regional interconnected inertia level	Yes	No	Interconnected
System-wide inertia level	Yes	No	Interconnected
Sub-network allocation	No	Yes	Interconnected
Secure and Satisfactory inertia levels	Yes	If there is a sub-network islanding risk	Islanded

## A2.8 Generator, network and market modelling assumptions

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

### A2.8.1 Generation outlook assumptions

Assumptions made about committed, anticipated and future generation projects as well as generator withdrawals are summarised in **Table 112** below.

**Table 112 Generation outlook assumptions**

<b>Committed generation projects</b>	<p>All NSCAS assessments – including thermal and voltage studies, fault level projections, and inertia projections – considered existing generators already in service as well as any in-commissioning, committed and committed* scheduled and semi scheduled generation projects from the July 2025 Generation Information page<sup>a</sup>.</p> <p>The IBR forecast component of the system strength requirements included newly committed projects from the October 2025 Generator Information page.</p>
<b>Anticipated and future generation projects</b>	<p>For system strength and inertia RSAS, AEMO considered scenarios featuring anticipated generation and storage projects as per the July 2025 Generation Information Page<sup>b</sup> to assess project impact.</p> <p>The fault level and inertia projections used the 2025 ESOO <i>Government Schemes and Actionable Developments</i> outlook. This included all in-commissioning, committed and anticipated generation and storage as per the July 2025 Generation Information page, as well generation supported by government schemes<sup>c</sup>.</p> <p>The IBR forecast component of the system strength requirements included newly anticipated projects from the October 2025 Generation Information page, as well as future generation from preliminary Draft 2026 ISP analysis.</p>
<b>Generation withdrawal</b>	<p>The NSCAS thermal and voltage studies, system strength and inertia projections in this report are aligned with the generator withdrawals in the <i>Step Change</i> scenario of the 2024 ISP with consideration of the following announcements:</p> <ul style="list-style-type: none"> <li>• Gladstone – on 29 September 2025, CS Energy advised AEMO of the potential closure of the 1,680 MW Gladstone Power Station in Queensland by submitting an updated closure date of 31 March 2029, which is earlier than the expected closure year of 2035 previously provided.</li> <li>• Torrens Island B – on 1 October 2025, AGL Energy advised AEMO of an extension to the previously notified closure of Torrens Island B power station units 2-4 from 30 June 2026 to 30 June 2028. The closure date for unit 1 remains 30 June 2026.</li> <li>• Eraring – in May 2024, Origin Energy advised AEMO of an extension to the previously notified closure of Eraring from 19 August 2025 to 19 August 2027.</li> </ul>

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

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

C. As detailed in Table 6, AEMO, 2025 ESOO, at [https://www.aemo.com.au/-/media/files/electricity/nem/planning\\_and\\_forecasting/nem\\_esoo/2025/2025-electricity-statement-of-opportunities.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf).

#### A2.8.1.1 Adjustments to the IBR forecast

The IBR forecasts presented in this report may include projects that have elected to be part of the old system strength framework, those which have chosen to self-remediate, or those which have not yet made a declaration as part of their connection process.

The intent of the efficient levels is to represent AEMO’s best view of the future IBR projects that will (or could) benefit from the centralised system strength services offered through SSSP investment. AEMO encourages SSSPs to apply their local knowledge in adjusting the efficient levels for application in their planning processes. This may include consideration of:

- whether proponents have elected to self-remediate through their connection application,
- whether proponents have elected to apply the old system strength connection framework if eligible to do so,
- whether proponents are part of a REZ development project that has committed to self-remediation or is proceeding outside the NER framework, and
- the proportion of future IBR that may be grid-forming (particularly batteries).

AEMO considers that SSSPs are likely better placed to determine the status of these decisions throughout the year, and between annual updates to the efficient levels. As such, AEMO encourages SSSPs to apply their local knowledge in adjusting the efficient levels for application in their planning processes.

### A2.8.2 System strength RIT-T modelling assumptions

Parts of the preferred option in each TNSP’s system strength RIT-T were modelled in the RIT-T outlook for both system strength and inertia projections where modelling information was available or a reasonable assumption could be made. The remainder of the preferred option was not modelled due to uncertainty with contracting or confidentiality. Through joint planning with TNSPs, AEMO has used the latest available modelling information including the most up to date location, timing, inertia, and fault level contribution for synchronous condensers based on current procurement status, and services from non-network synchronous condensers and synchronous generation where a proponent has been identified. **Table 113** provides details for each jurisdiction.

**Table 113 Modelled parts of RIT-T preferred option included in the RIT-T outlook for fault level and inertia projections**

System Strength Service Provider	Part of RIT-T preferred solution	Included in the RIT-T outlook for fault level and inertia projections?
Transgrid <sup>A</sup>	Ten network synchronous condensers	Included with latest modelling information based on the outcome of a tender for synchronous condensers <sup>9</sup> .
	Non-network contracts with synchronous units	Only one synchronous power station was included based on available information leading up to publication of this report. More contracts are expected in the final portfolio of non-network contracts upon completion of tendering.
	GFM BESS	Not included in fault level projections due to current lack of evidence that GFM BESS can provide protection quality fault current. Not included in inertia projections as synthetic inertia constants have not been calculated.
Powerlink <sup>C</sup>	Nine network synchronous condensers	Included.
	Non-network contracts with synchronous units	Not included as information was not available leading up to publication of this report.
	GFM BESS	Not included in fault level projections due to current lack of evidence that GFM BESS can provide protection quality fault current. Not included in inertia projections as synthetic inertia constants have not been calculated.
ElectraNet <sup>D</sup>	Clutch installation for potential future gas generation	Not included as no new future gas generation is included in fault level and inertia projections.
VicGrid <sup>E</sup>	Five network synchronous condensers	Included.
	Non-network contracts with synchronous units	Contracting with one existing synchronous condenser at the Red Cliffs system strength node was included. No contracts with synchronous generation were included based on available information leading up to publication of this report. Contracts with

System Strength Service Provider	Part of RIT-T preferred solution	Included in the RIT-T outlook for fault level and inertia projections?
		synchronous generation are expected in the final portfolio of non-network contracts upon completion of tendering.
	GFM BESS	Not included in fault level projections due to current lack of evidence that GFM BESS can provide protection quality fault current. Not included in inertia projections as synthetic inertia constants have not been calculated.
TasNetworks <sup>f</sup>	Non-network contracts with synchronous units	The information for the full portfolio of planned non-network contracts under the RIT-T was included.

A. Transgrid, *Meeting system strength requirements in New South Wales Project Assessment Conclusions Report*, 2025, at <https://www.transgrid.com.au/media/kfhd21bg/250812-transgrid-system-strength-pacr.pdf>.

B. See <https://www.transgrid.com.au/media-publications/news-articles/nsw-secures-critical-grid-stabilising-machines-to-support-renewables-rollout>.

C. Powerlink, *Addressing System Strength Requirements in Queensland from December 2025 Project Assessment Conclusions Report*, 2025, at <https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf>.

D. Electranet, *Meeting System Strength Requirements in South Australia Project Assessment Draft Report*, 2025, <https://electranet.com.au/wp-content/uploads/2025/04/RIT-T-PADR-Meeting-System-Strength-in-SA.pdf>.

E. AVP, *Victorian System Strength Requirement Project Assessment Conclusions Report*, 2025, at <https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf>.

F. TasNetworks, *Meeting the System Strength Standard in Tasmania from December 2025 onward*, 2025, at

<https://www.tasnetworks.com.au/config/getattachment/d15ecd38-f6a3-4b6c-bc68-61909ef48c15/tasnetworks-system-strength-rit-t-pacr-june-2025.pdf>.

Existing and committed sources of synchronous fault level and inertia, such as services procured to address previously declared system strength and inertia shortfalls and synchronous condensers included in the scope of committed augmentations, were included in both the base case and RIT-T outlooks. These are summarised in **Table 114**.

**Table 114 Existing and committed sources of fault level and inertia included in both base case and RIT-T outlooks for fault level and inertia projections.**

Proponent	Service description	Timing
VicGrid on behalf of the Victorian Government	250 MVA synchronous condenser at Ararat Terminal Station	February 2026
VicGrid	Contracts with non-network synchronous condensers at the Red Cliffs system strength node.	Existing until expiry in July 2026
Transgrid	Two synchronous condensers at Buronga 330 kV and two synchronous condensers at Dinawan 330 kV delivered by Project Energy Connect	Buronga synchronous condensers: existing Dinawan synchronous condensers: October 2026
EnergyCo	Seven 250 MVA synchronous condensers delivered by Central-West Orana REZ Infrastructure Project	Staged delivery from December 2028
ElectraNet	Four 125 MVA synchronous condensers at Davenport and Robertstown	Existing
Powerlink	Non-network contract with a gas unit in North Queensland to operate in synchronous condenser mode via a clutch.	Existing until expiry.

### A2.8.3 Transmission network augmentations

AEMO considered the following transmission augmentation projects as part of system strength, inertia and NSCAS thermal and voltage modelling work. Project scopes, status and timings were in general sourced from the Transmission Augmentation Information Page July 2025 edition<sup>80</sup> and the 2025 *Electricity Network Options Report*<sup>81</sup>, unless more recent

<sup>80</sup>AEMO, *Transmission Augmentation Information Page*, July 2025, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

<sup>81</sup>AEMO, *Electricity Networks Options Report*, August 2025, at [https://www.aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/final/2025-electricity-network-options-report.pdf?rev=7fd2059752bd41eba55184df4e389e1e&sc\\_lang=en](https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/final/2025-electricity-network-options-report.pdf?rev=7fd2059752bd41eba55184df4e389e1e&sc_lang=en).

information has been provided to AEMO. Timings captured in this table are advised in-service dates; capacity release dates where applicable are subject to inter-network testing conditions being met.

**Table 115 Transmission augmentations considered as part of system strength, inertia and NSCAS voltage and thermal assessments**

Region	Project name	Augmentation detail	Status	Modelling date (calendar year) <sup>A</sup>	Included in assessment
SA, NSW, VIC	<b>Project EnergyConnect Stage 1</b>	<p>Stage 1:</p> <ul style="list-style-type: none"> <li>• A new Robertstown to Bunday 275 kV double-circuit line strung one circuit initially.</li> <li>• A new Bunday to Buronga 330 kV double-circuit line strung one circuit initially.</li> <li>• A new Buronga to Red Cliffs 220 kV double-circuit line strung one circuit only.</li> <li>• A new 330/275 kV substation and a 330/275 kV transformer at Bunday.</li> <li>• A new 330/220 kV substation, a 330/220 kV transformer and a 330 kV phase shifting transformer at Buronga.</li> <li>• Static and dynamic reactive plant at Bunday and Buronga.</li> </ul>	In-service	In-service	System strength projections, inertia projections and NSCAS voltage and thermal studies.
	<b>Project EnergyConnect - Stage 2<sup>B</sup></b>	<p>Stage 2:</p> <ul style="list-style-type: none"> <li>• Second 330 kV circuit closed on the Bunday–Buronga 330 kV double-circuit line (including 1 x 60 MVAR line reactor at Bunday and 1 x 50 MVAR line reactor at Buronga of each circuit).</li> <li>• A new 330 kV double-circuit line from Dinawan to Buronga (including 60 MVAR line reactors at both ends of each circuit).</li> <li>• A new 500 kV double-circuit line from Dinawan to Wagga Wagga operating at 330 kV (including 50 MVAR line reactors at the Dinawan end on each circuit).</li> <li>• A new 330 kV switching station at Dinawan.</li> <li>• Additional 4 x 200 MVA 330 kV phase shifting transformers at Buronga.</li> <li>• Additional 2 x 200 MVA 330/220 kV transformers at Buronga.</li> <li>• New 2 x 100 MVA 330 kV connected synchronous condenser at Dinawan</li> <li>• New 2 x 52 MVAR 330 kV capacitor banks at Dinawan.</li> <li>• An additional 1 x 100 MVA 330 kV connected synchronous condenser at Buronga</li> <li>• A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia.</li> </ul>	Committed	Oct-2026	System strength projections, inertia projections and NSCAS voltage and thermal studies.
	<b>Western Renewables Link (WRL)</b>	<ul style="list-style-type: none"> <li>• A new 500 kV double-circuit transmission line from Sydenham Terminal Station to Bulgana Terminal Station with switched shunt line reactors at the end of each circuit (approximately 70 MVAR).</li> <li>• Extension of the 500 kV Sydenham Terminal Station by two breaker and a half switched bays</li> <li>• Additional 100 MVAR at 500 kV switched bus reactor at Sydenham Terminal Station.</li> </ul>	Anticipated	Nov-29	System strength and inertia projections

Region	Project name	Augmentation detail	Status	Modelling date (calendar year) <sup>A</sup>	Included in assessment
		<ul style="list-style-type: none"> <li>Rerouting of the existing No. 1 Sydenham to South Morang and Sydenham to Keilor 500 kV transmission lines to terminate into new bays at Sydenham Terminal Station.</li> <li>Construction of new 220 kV circuit breakers and a second 220 kV bus at Bulgana Terminal Station.</li> <li>A new 500 kV switchyard at Bulgana Terminal Station with two new 500/220 kV 1,000 MVA transformers, transmission line realignment, site provisioning and line cut in works for the existing Bulgana to Horsham 220 kV transmission line and Crowlands to Bulgana 220kV transmission line.</li> <li>Cut-in, termination and switching of the existing Ballarat to Moorabool No.2 220 kV transmission line at Elaine Terminal Station, forming Ballarat to Elaine No.2 line and Elaine to Moorabool No.2 line.</li> <li>Re-alignment and switching of the existing Ballarat to Elaine transmission line and Elaine to Moorabool transmission lines at Elaine Terminal Station and renaming them to Ballarat to Elaine No.3 line and Elaine to Moorabool No.3 line.</li> <li>Implement new Special Control Schemes and/or amend some existing ones at multiple stations.</li> <li>Validation of the capabilities of the existing earthing systems at multiple stations and the connected 220 kV transmission lines optic ground wire and/or earth wire.</li> <li>Minor augmentations at existing terminal stations impacted by the WRL works.</li> </ul>			
NSW	<b>Central-West Orana renewable energy zone (REZ) Transmission Link<sup>C</sup></b>	<ul style="list-style-type: none"> <li>New Merotherie 500/330 kV substation with 4 x 500/330/33 kV 1,500 MVA transformers.</li> <li>New 330 kV Elong Elong switching stations.</li> <li>New 500 kV Barigan Creek switching station.</li> <li>2 x 500 kV double-circuit lines from Barigan Creek to Merotherie with Quad Orange conductor.</li> <li>2 x 500 kV double-circuit lines and initially operated at 330 kV from Merotherie to Elong Elong with Quad Orange conductor.</li> <li>3 x 250 MVA synchronous condensers at Elong Elong switching station.</li> <li>4 x 250 MVA synchronous condensers at Merotherie substation.</li> <li>Provision of switch bays for future generator connections (cost estimation is not required)</li> <li>An additional 330 kV single-circuit line from Bayswater to Liddell.</li> <li>An additional 330 kV single-circuit line from Mt Piper to Wallerawang.                             <ul style="list-style-type: none"> <li>Possible expansion to Uungula/Burrendong is subject to a separate and future project authorisation process.</li> </ul> </li> </ul>	Committed	Dec-2028	System strength projections, inertia projections and NSCAS voltage and thermal studies.
	<b>Waratah Super Battery Network Augmentations and SIPS Control</b>	<p>Transmission augmentations to the network:</p> <ul style="list-style-type: none"> <li>Uprate of Bannaby – Sydney West, Yass – Collector, Collector – Marulan and Yass – Marulan 330 kV transmission lines.</li> </ul>	Committed	Line uprates in-service	System strength projections, inertia projections and NSCAS voltage and thermal studies.

Region	Project name	Augmentation detail	Status	Modelling date (calendar year) <sup>A</sup>	Included in assessment
		<ul style="list-style-type: none"> <li>Upgrade equipment at 22 substations along the northern and southern transmission line routes.</li> <li>Link tendered paired generation to Waratah Super Battery with SIPS control scheme.</li> <li>SIPS control delivered by Transgrid.</li> </ul>			
	<b>HumeLink</b>	<ul style="list-style-type: none"> <li>New Gugaa 500/330 kV Substation and 330 kV connection to the existing Wagga Wagga Substation</li> <li>Three 500 kV transmission circuits and shunt reactors:                             <ul style="list-style-type: none"> <li>Between Maragle and Bannaby 500 kV Substation, 120 MVar shunt reactor at both ends,</li> <li>Between Maragle and Gugaa 500 kV Substation, 100 MVar shunt reactor at Maragle end and</li> <li>Between Gugaa and Bannaby 500 kV Substation, 120 MVar shunt reactors at both ends.</li> </ul> </li> </ul> <p>The above circuits will be built on double-circuit transmission structures.</p> <ul style="list-style-type: none"> <li>Three new 500/330/33 kV 1,500 MVA transformers at Maragle Substation and two new 500/330/33 kV 1,500 MVA transformers at new Gugaa Substation.</li> <li>Augment the Maragle Substation to accommodate the additional transmission lines.</li> <li>Augment the existing substations at Wagga Wagga and Bannaby to accommodate the additional transmission lines/transformers.</li> </ul>	Committed	Dec-2027	System strength projections, inertia projections and NSCAS voltage and thermal studies.
	<b>Hunter-Central Coast REZ Network Infrastructure project.</b>	EnergyCo has appointed Ausgrid as the Network operator (Commitment Deed executed December 2024) to deliver the HCC REZ 1 GW network transfer capacity. The scope comprises of electricity distribution network upgrades between Kurri substation and Muswellbrook bulk supply point in three portions.	Actionable NSW	Component 1: Dec-25 Component 2: Jun-28 Component 3: Jul-28	System strength and inertia projections
	<b>Sydney Ring South (Reinforcing Sydney, Newcastle, and Wollongong Supply)</b>	<p>Option 2d: (ISP candidate option) Power flow control on the 330 kV network</p> <ul style="list-style-type: none"> <li>Install power flow control devices in the 330 kV network supplying Sydney from the south.</li> </ul>	Actionable ISP (2024 ISP Candidate Option)	September-2028	System strength and inertia projections
QLD	<b>Gladstone Project</b>	<ul style="list-style-type: none"> <li>New Gladstone West 275 kV switching station.</li> <li>New 275 kV high capacity double-circuit line between Calvale and Calliope River (switched into Gladstone West).</li> <li>A new (third) 275/132 kV transformer at Calliope River.</li> <li>Power flow control of Calvale – Wurdong 275 kV line.</li> <li>200 MVar capacitor bank at Larcom Creek and Calliope River.</li> <li>150 MVar reactor at Gladstone West.</li> <li>Two synchronous condensers at Gladstone West.</li> <li>Wide area monitoring, control and protection scheme.</li> <li>Rebuild Bouldercombe - Calliope River 275kV (#812) as a high capacity Bouldercombe - Larcom Creek</li> </ul>	Actionable QLD	31/03/2029	NSCAS voltage and thermal studies (as a sensitivity)

Region	Project name	Augmentation detail	Status	Modelling date (calendar year) <sup>A</sup>	Included in assessment
		<p>275kV double-circuit line (switched into Gladstone West).</p> <p>Notes: (1) Retain the existing Calliope River-Larcom Creek-Raglan Bouldercombe 275 kV line (#s 8859, 8875 and 811) in service (2) Decommission #812 from Bouldercombe to Gladstone West but retain #812 from Gladstone West to Calliope River</p>			
SA	<b>Transmission Network Voltage Control</b>	Install a total of four 60 Mvar 275 kV reactors around the Adelaide metropolitan region and a single 50 Mvar 275 kV reactor at South East.	Committed	Staged delivery, completion of all reactors expected Oct-2027	NSCAS voltage and thermal studies.
	<b>Eyre Peninsula upgrade Option 1</b>	<ul style="list-style-type: none"> <li>A new Yadnarie North substation with two new 275/132 kV transformers.</li> <li>Operate the Cultana – Yadnarie 132 kV double-circuit line (built as part of the Eyre Peninsula Link RIT-T) at 275 kV.</li> <li>Reconnect 132 kV connections to 275 kV at both Yadnarie North and Cultana.</li> </ul>	Actionable ISP	1/07/2030 <sup>E</sup>	System strength and inertia projections
VIC	<b>Mortlake turn-in</b>	<p>The Mortlake turn-in consists of:</p> <ul style="list-style-type: none"> <li>installing four new 500 kV circuit breakers and associated equipment to fully populate one of the existing 500 kV bays and establish a new additional 500 kV bay at Mortlake Power Station, and</li> <li>connecting the existing Haunted Gully to Tarrone 500 kV circuit, of the Moorabool – Heywood 500 kV double circuit line, into Mortlake Terminal Station to establish a Haunted Gully – Mortlake 500 kV circuit and a Mortlake to Tarrone 500 kV circuit.</li> </ul>	In-service	In-service	System strength projections, inertia projections and NSCAS voltage and thermal studies
	<b>Latrobe Valley switching configuration - modified parallel mode</b>	The Latrobe Valley reconfiguration project was identified in the 2023 VAPR to enhance the utilisation of 220 kV network between Latrobe Valley and Melbourne and reduce reliability risks after retirement of YWPS. It involves rearrangement of existing infrastructure to minimise risks of overloading transformers and lines at times of high demand post the retirement of YWPS.	Victorian future project	1/07/2028	System strength projections, inertia projections and NSCAS voltage and thermal studies
	<b>Eastern Victoria reinforcement program - Part 1<sup>P</sup></b>	<p>Eastern Victoria reinforcement program</p> <ul style="list-style-type: none"> <li>Install a second Hazelwood - Yallourn double circuit line.</li> <li>Install a second 500/220 kV transformer at Cranbourne and tie in existing Hazelwood-Rowville 500 kV (no 3) circuit at Cranbourne.</li> <li>Load management of works on the Rowville - Templestowe - Thomastown 220 kV line and Rowville - Ringwood to Thomastown 220 kV circuit.</li> <li>Fault level mitigation at Keilor, Rowville, South Morang, Thomastown 220 kV busses and Templestowe and Thomastown 66 kV buses.</li> </ul>	Victorian future project	1/12/2028	System strength projections and inertia projections
	<b>Western Victoria reinforcement program<sup>P</sup></b>	<p>Western Victoria reinforcement program</p> <ul style="list-style-type: none"> <li>Increase rating of Moorabool - Geelong 220 kV circuits 1 and 2 - (Check rating increase at least 385 MVA).</li> <li>Replace the H1 and H2 South Morang Transformers.</li> <li>Rebuild the existing Ballarat - Moorabool line into a high capacity double circuit line.</li> </ul>	Victorian future project	1/12/2028	System strength projections and inertia projections

Region	Project name	Augmentation detail	Status	Modelling date (calendar year) <sup>A</sup>	Included in assessment
		<ul style="list-style-type: none"> <li>Switch the existing Geelong to Keilor circuits at Deer Park (No 1 and 3). This project assumes that the three 220 kV lines running from Deer Park to Keilor will operate as normally open (Draft 2025 VTP, Appendix Af).</li> </ul>			
VIC,TAS	<b>Project Marinus Stage 1</b>	Project Marinus Stage 1 (includes MarinusLink Cable 1 and the associated TasNetworks equipment for the North West Transmission Development Project) <ul style="list-style-type: none"> <li>A 750 MW monopole HVDC link between Burnie area in Tasmania and Hazelwood area in Victoria.</li> <li>A new 750 MW HVDC monopole converter station in Burnie area.</li> <li>A new 750 MW HVDC monopole converter station in Hazelwood area.</li> <li>A new 220 kV switching station at Heybridge adjacent to the converter station.</li> <li>A new double-circuit 220 kV transmission line between Sheffield, Heybridge and Burnie</li> <li>A new 220 kV double-circuit line from Palmerston to Sheffield with decommissioning of the existing single-circuit line.</li> <li>A new 500 kV connection from converter station in Hazelwood area.</li> <li>Decommission existing Sheffield – Burnie 220 kV line.</li> </ul>	Actionable ISP (2024 ISP Candidate Option)	1/07/2030	System strength projections and inertia projections

A. Modelling dates are consistent with those applied in the original 2025 ESOO. For some of the nearer-term projects, AEMO is aware of some delays to delivery and commissioning. However, in these cases AEMO does not consider the delays to be impactful for the purposes of system strength and inertia assessments and so the modelling dates are unchanged.

B. AEMO has incorporated recent advice from VicGrid on the status of the second synchronous condenser at Buronga originally to be delivered as part of Project Energy Connect Stage 2. VicGrid has advised AEMO that this asset has been commissioned early and is now in-service.

C. AEMO has modelled a staged delivery of the seven synchronous condensers in Central-West Orana from the modelling date specified as per timing advice from EnergyCo.

D. AEMO is aware that the scope and expected delivery timing of the East and West Victorian Grid Reinforcement projects has changed since information considered here. AEMO will continue to monitor these projects as they advance through both RIT-T and Victorian transmission investment frameworks.

E. AEMO has considered the 2024 ISP four year lead time for commissioning of the Eyre Peninsula upgrade project. ElectraNet's TAPR notes the need as 2029 - 2033.

F. See <https://engage.vic.gov.au/victransmissionplan> for further details

AEMO undertakes integrated energy market modelling to forecast future investment in and operation of electricity generation, storage and transmission in the NEM<sup>82</sup>.

The market model used in the 2025 ESOO *Government Schemes and Actionable Developments* scenario has been used for this report, with changes as shown in **0** below.

<sup>82</sup> AEMO. 2025 *ISP Methodology*, at [https://www.aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf](https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf).

**Table 116 Market modelling inputs and settings used in system strength and inertia NSCAS projections**

Input	Assumption
<b>Time Horizon</b>	Five financial years from 2025-26 to 2029-30.
<b>Scenario</b>	2025 ESOO <i>Government Schemes and Actionable Developments</i> – which assumes all in-commissioning, committed and anticipated generation, storage and transmission developments are delivered on time, and also the on-time delivery of government schemes supported by delivery mechanisms.
<b>Bidding</b>	Generator dispatch projections are from a time-sequential model using the ‘bidding behaviour model’ for realistic generator dispatch results given the generation and build outcomes. The bidding behaviour model uses historical analysis of actual generator bidding data and back-cast approaches for the purposes of calibrating projected dispatch <sup>A</sup> .
<b>Demand</b>	Applied the <i>Step Change</i> scenario 50% probability of exceedance (POE) demand projection from the 2025 ESOO for the NEM.
<b>Reference year</b>	2020
<b>Unplanned outages</b>	Applied projections of unplanned generation outages based Monte Carlo simulation. 50 outage patterns were applied per simulated year. No unplanned outages are applied to synchronous condensers or network plant.
<b>Planned Maintenance</b>	Applied projections of planned maintenance based on MT PASA data and then repeated every two years.
<b>Market Dynamics</b>	Desynchronising of one coal power station in New South Wales has been considered.
<b>Constraints</b>	Thermal and stability constraints included as per the 2025 ESOO <i>Government Schemes and Actionable Developments</i> scenario. Minimum unit constraints are turned off where they related to system strength and inertia. Daily gas usage constraints for GPG and hydro ecological constraints are included.

A. Details for the bidding behaviour model are in AEMO’s 2025 *ISP Methodology*, at [https://www.aemo.com.au/-/media/files/stakeholder\\_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf](https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf).

### Desynchronising of coal plant

The system strength and inertia projections also considered desynchronising of one coal power station in New South Wales. This is where an individual unit is not electrically connected to the grid, and either a steam bypass is used or the boiler is shut down (sometimes referred to as two-shifting). In this arrangement, the generator is not contributing to system strength and inertia but can return to a normal, synchronised operation within a matter of hours<sup>83</sup>. Desynchronised operation is now being observed for some thermal units in the NEM – particularly in New South Wales.

<sup>83</sup> See Section 4.8 of AEMO 2025 Thermal Audit, at [https://www.aemo.com.au/-/media/files/electricity/nem/security\\_and\\_reliability/power\\_system\\_ops/2025-thermal-audit.pdf](https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/2025-thermal-audit.pdf).

## A2.9 Translation of minimum fault level requirements to real-time operations

AEMO is required to publish minimum fault level requirements for each system strength node applicable for the following year under NER 5.20C.1(c)(1) for the purposes of clauses 4.2.6(g), 4.4A.3(b)(4) and 4.6.1(b). Maintaining the system strength requirements at each node forms part of the general power system principles to operate a secure network as per NER 4.2.6(g).

The minimum fault level requirements translate to real-time operations such that if the operational conditions match the planning assumptions studied, then these minimum fault levels are expected to be maintained. This may be, if necessary, through the enablement of system strength services under NER 4.4.5(a) (enablement of system security services will be under NER 4.4A.5 from 2 December 2025).

The minimum fault level requirements have been assessed for pre-contingent system normal conditions given a particular set of planning assumptions. The requirements do not account for planned or unplanned outages or other operational conditions outside of an intact system that might occur in the network. Where circumstances outside of the planning assumptions may occur, the minimum fault level requirements may not be able to be maintained even with the enablement of system strength services under NER 4.4.5(a). Under those conditions, AEMO and TNSPs will work together to determine appropriate limits advice for the given conditions to keep the power system secure as required under NER 4.3.2(a).

**Table 117** lists the pre-contingency minimum fault level requirements for each system strength node as at 2 December 2025.

**Table 117 Pre-contingency minimum fault level requirements for each system strength node**

Region	System strength node	Minimum fault level requirement (pre-contingency) (MVA)
New South Wales	Armidale 330 kV	3,300
	Buronga 220 kV	1,755
	Darlington Point 330 kV	1,500
	Newcastle 330 kV	8,150
	Sydney West 330 kV	8,450
	Wellington 330 kV	2,900
Queensland	Gin Gin 275 kV	2,800
	Greenbank 275 kV	4,350
	Lilyvale 132 kV	1,400
	Ross 275 kV	1,350
	Western Downs 275 kV	4,000
South Australia	Davenport 275 kV	2,400
	Para 275 kV	2,250
	Robertstown 275 kV	2,550
Tasmanian	Burnie 110 kV	850 <sup>B</sup>
	George Town 220 kV	1,450
	Risdon 110 kV	1,330
	Waddamana 220 kV	1,400

Region	System strength node	Minimum fault level requirement (pre-contingency) (MVA)
Victoria	Dederang 220 kV	3,500
	Hazelwood 500 kV	7,700
	Moorabool 220 kV	4,600
	Red Cliffs 220 kV	1,786
	Thomastown 220 kV	4,700

A. These requirements are calculated to ensure system security for the ‘worst credible contingency’. Non-credible events like the inability of synchronous generators to ride through a circuit breaker fail event have not been considered. AEMO’s view is events like this and the resulting loss of resilience of the system should be taken into consideration by the SSSP when meeting the system strength standard.

B. The pre-contingent minimum fault level requirement at Burnie is expected to reduce from 850 MVA in 2025-26 to 750 MVA in 2026-27 following commissioning of a STATCOM at Port Latta Wind Farm.