Appendix 7. System Security

June 2024

Appendix to the 2024 Integrated System Plan for the National Electricity Market

Important notice

Purpose

This is Appendix 7 to the 2024 Integrated System Plan (ISP) which is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp. AEMO publishes the 2024 *Integrated System Plan* (ISP) pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its supporting functions under the National Electricity Rules. This publication is generally based on information available to AEMO as at 1 May 2024 unless otherwise indicated.

Disclaimer

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Version control

Version	Release date	Changes
1.0	26/6/2024	First release.

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

ISP Appendices

Contents

Tables

Figures

Executive summary

AEMO's *Integrated System Plan* (ISP) is a roadmap for the transition of the National Electricity Market (NEM) power system, with a clear plan for essential infrastructure that will meet future energy needs. The ISP's optimal development path (ODP) sets out the needed generation, storage and network investments to transition to net zero by 2050 through current policy settings and deliver significant net market benefits for consumers.

AEMO has identified a rapidly growing need for coordinated investment in system security services across the NEM. These services are necessary to enable delivery of the development plans considered in the ISP and are crucial to maintaining a secure and resilient power system throughout the energy transition.

This appendix quantifies these emerging requirements, and provides insights into the nature, timing, and geography of the services needed to address them.

AEMO has assessed the emerging need for system strength and inertia in the *Step Change* scenario. This work builds on the existing assessments in AEMO's annual security planning reports[1], and extends their outlook period to cover a 20-year horizon at five-yearly increments. It sets out:

- **A7.1 Recent reforms to the security planning frameworks** – this section provides an overview of recent and ongoing regulatory reforms relevant to the power system security analysis in this appendix. These reforms aim to deliver increasingly efficient and proactive investment in fit-for-purpose services.
- **A7.2 AEMO's approach to system security planning** – this section explains AEMO's overlapping approach to power system security planning across multiple timeframes spanning urgent shortfalls to strategic planning, and across a broad remit of potential security services.
- **A7.3 System security concepts and requirements** – this section describes the technical, economic, and locational drivers for these services in the context of the security assessments presented later in the appendix.
- **A7.4 Projected outlook and opportunities** – this section defines the minimum system security planning standards for each NEM region, the factors that influence how these will evolve, and the expected adequacy of services available to address them. This section is structured geographically to reflect the nature of network investment obligations, and to comment on any potential options for co-optimised investment in multiple security services from a single asset or provider.

Key findings across the NEM

This appendix highlights the following emerging requirements for each NEM region:

- **New South Wales** – declining utilisation of synchronous generation is expected to reduce synchronous fault levels at some nodes, while major network projects like the Sydney Ring North will provide relief at others. Most associated remediation will be needed over the coming decade, and shortfalls have already been declared for Newcastle and Sydney West from July 2025. Substantial growth in inverter-based resources (IBR) generation and storage will drive further investment in system strength over the full 20-year outlook period.

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

Projected levels of inertia also decline significantly over the horizon, however strong interconnection with neighbouring regions means New South Wales is not considered sufficiently likely to island.

- **Queensland** – similar to New South Wales, decreased utilisation of synchronous generation is expected to reduce synchronous fault levels at all nodes in the region, with most associated remediation investment likely needed over the coming decade. Substantial investment in wind and solar IBR, particularly near the Gin Gin and Western Downs nodes, will drive ongoing investment in system strength services. AEMO has declared an inertia shortfall in Queensland from 2027-28, and available inertia levels are projected to decline further over the 20-year horizon.
- **South Australia** – four large synchronous condensers in South Australia provide sufficient fault current to meet minimum requirements across the horizon. However, significant IBR build, particularly near the Davenport and Robertstown nodes, will require a corresponding investment in system strength services. Projected levels of available inertia are already below minimum secure operating levels and are not projected to recover over the study period. However, South Australia is not considered likely to island once Project EnergyConnect (PEC) Stage 2 is commissioned and protection schemes are in place.
- **Tasmania** – system strength and inertia shortfalls are projected across the 20-year horizon for Tasmania. The magnitude of these is driven primarily by growth in local IBR and changes in energy exports to the mainland, which combine to impact utilisation of local synchronous hydro generation.
- **Victoria** – declining utilisation of synchronous generation is expected to reduce synchronous fault levels at most system strength nodes in Victoria. Most of the investment needed to address these issues will likely be required within the coming decade, however substantial IBR growth will continue to drive investment in system strength services over the longer term. Projected levels of available inertia are already below minimum secure operating levels, but strong interconnection with neighbouring regions means that Victoria is not considered sufficiently likely to island.

Key changes from the Draft 2024 ISP

- The final *Step Change* scenario generator, storage and transmission build outcomes have been used to produce revised IBR, system strength and inertia projections in this appendix. The final *Step Change* scenario is similar to the Draft 2024 ISP, with some shifts in build outcomes. The revised projections are presented in A1.4.
- On 28 March 2024, the Australian Energy Market Commission (AEMC) made a final determination and final rule to improve security frameworks for the energy transition. The improving security frameworks (ISF) final rule makes various improvements to proactively address system security issues. The ISF final rule is discussed further in A1.1.

A1.1 Recent reforms to the security planning frameworks

The energy transition is transforming the way electricity is generated, transported, and consumed across the NEM. The pace of this change is still accelerating, and traditional ways of operating are being challenged as system security and reliability become increasingly complex.

The scope of these technological and economic changes must be matched by a supportive and adaptive regulatory framework that can drive action on critical services, remove unnecessary barriers to participation, and streamline investment in least-regret assets and services.

The system security planning frameworks have undergone a series of major overhauls in recent years to ensure they remain fit for purpose, and to continually push for more efficient long-term outcomes.

Changes have been introduced to drive proactive system strength investment

In October 2021, the AEMC amended the system strength framework to drive more proactivity in the provision of system strength services, to deliver a streamlined connection process, and to leverage economies of scale in larger, centralised investments. A new mechanism was also introduced to allow connection applicants to decide between procuring their own system strength assets or contributing towards a fleet of centrally provided services.

The regulatory aspects of the new framework have been progressively finalised over the past 18 months, and implementation activities have now shifted from defining the new standards and guidelines, to coordinating assessment and delivery against them. This process has identified several challenges and friction points in the new framework, and AEMO is continuing to work closely with the AEMC, Australian Energy Regulator (AER), and market participants to identify and prioritise any potential improvements.

Regulatory investment tests for transmission (RIT-Ts) are already underway in every region to deliver the first round of system strength investment, and the ISP provides a key input into those processes via the IBR investment patterns that underpin the system strength requirements.

New frequency standards, obligations, and markets are now in effect

Inertia services are only one in a portfolio of frequency management tools that are currently in place or are being progressed through regulatory reforms. While inertia has long been an important complement to the frequency control ancillary services (FCAS) markets, new tools and standards have also been introduced to address needs in the sub 6-second range where inertia was previously the primary tool available:

- **Revised Frequency Operating Standard (FOS)** – the Reliability Panel has introduced a new rate of change of frequency (RoCoF) standard of 1 hertz per second (Hz/s) for all mainland NEM regions[2], and retains the existing 3 Hz/s requirement in Tasmania. The revised standard came into effect on 9 October 2023.
- **Mandatory primary frequency response (PFR)** – the AEMC has introduced an enduring set of requirements mandating provision of PFR services from all generation with the capability to do so.

[2] AEMC. Review of the Frequency Operating Standard 2022, at https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022.

- **Introduction of a very fast (1-second) FCAS market** – AEMO introduced two new FCAS markets (very fast raise and very fast lower) on 9 October 2023.

These new services and reforms improve AEMO's ability to maintain secure frequency levels.

Changes have been introduced to improve the way system strength charges are calculated

On 29 February 2024, the AEMC published a final determination and more preferable final rule to alter the calculation methodology for the system strength quantity (SSQ) component of the system strength charge[3]. Under the final rule, the SSQ will better reflect the system strength impact of a new connection or alteration at a connection point, via the following changes:

- The removal of the SSQ calculation from the National Electricity Rules (NER), replaced by a requirement for AEMO to determine a methodology for calculating SSQ.
- The introduction of guiding policy principles in the NER to assist AEMO's development of the SSQ methodology.
- The clarification of the process to move from an indicative to a final SSQ.

The new arrangements will commence on 1 July 2024.

Changes have been introduced to improve and align existing security frameworks

On 28 March 2024, the AEMC made a final determination and more preferable final rule to improve security frameworks for the energy transition[4]. The ISF final rule makes several improvements to proactively address system security issues, as follows.

- The introduction of a new mainland NEM-wide inertia floor, and the alignment of the existing inertia and system strength frameworks procurement timeframes. The rule also allows transmission network service providers (TNSPs) to procure synthetic inertia to meet minimum inertia levels, subject to AEMO's approval.
- The removal of the exclusion to procuring inertia and system strength network services under the network support and control ancillary services (NSCAS) framework, to allow TNSPs to address near-term gaps.
- Adjustment to the cost recovery process for any TNSP non-network security contracts, to support efficient contracting arrangements and reduce volatility for consumers.
- The creation of a new transitional non-market ancillary services (NMAS) framework for AEMO to procure security services not otherwise covered by NSCAS and to trial new ways of securing the system.
- Amendment of AEMO's obligations for scheduling system security contracts to require AEMO to consider a whole-of-NEM perspective.
- Improved transparency around directions issued by AEMO, through requiring market notices to be published with directions and several updated reporting obligations on AEMO.

[3] See https://www.aemc.gov.au/rule-changes/calculation-system-strength-quantity.

[4] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

- The introduction of a new annual requirement on AEMO to produce a ‘transition plan for system security’ (or transition plan), which will describe the work AEMO is doing to address security challenges during the energy transition, now and into the future.

The final rule will be implemented in stages, as follows:

- 3 June 2024 – the transitional services framework will commence. AEMO will only be able to procure transitional services after the publication of the transitional services guideline (which must be published by 1 December 2024).
- 4 July 2024 – the new obligation to publish market notices and updates to several directions reporting obligations will commence.
- 1 December 2024:
  - The new inertia framework will commence, including the NSCAS exclusion removal.
  - The revisions to the TNSP cost recovery approach for non-network security contracts will commence.
  - The first transition plan must be published by AEMO.
- 2 December 2025 – full enablement obligations on AEMO will commence.

A1.2 AEMO's approach to system security planning

Effective system security management requires a range of tools and frameworks working in tandem, across multiple timescales, participant types, and geographic areas. Figure 1 summarises AEMO's multilayered approach, and the linkages between the current and future state of the power system:

- **In the near term (0 to 5 years)** – AEMO undertakes detailed power system analysis and market simulation to set system standards, determine security requirements, forecast levels of available system services, and declare any prevailing shortfalls. AEMO has a special planning role in this timeframe, where TNSPs must use all reasonable endeavours to remediate any declared shortfalls, and AEMO may exercise a last resort planning power to procure services where none would otherwise be forthcoming.
- **In the medium term (0 to 10 years)** – AEMO is progressing an Engineering Roadmap[5] which aims to prepare the system to operate securely and reliably during periods of 100% instantaneous penetration of renewables. This is part of AEMO's overarching Engineering Framework that seeks to develop tools necessary to meet all operational, technical, and engineering requirements of the future power system.
- **In the long term (0 to 20 years)** – the ISP provides AEMO's view on the ODP for the system as a whole and provides a solid plan for a planning horizon of 20 years on which system security requirements can be identified, quantified, and proactively planned for.

[5] AEMO. *Engineering Roadmap to 100% Renewables*, at https://aemo.com.au/initiatives/major-programs/engineering-framework.

Figure 1 Overview of key system security planning timeframes and reports

Near Term 0 to 5 Years	Medium Term 0 to 10 Years	Long Term 0 to 20 Years
System Security Reports Detailed annual assessment of system requirements, capabilities, and shortfalls to trigger investment in system security services.	**Engineering Framework** A plan to navigate the energy transition and develop the tools needed to meet all operational and engineering requirements of the future power system.	**Integrated System Plan** AEMO's long-term view of the optimal development pathway for the power system, considering a range of possible future scenarios.

A1.3 System security concepts and requirements

A1.3.1 System strength

System strength describes the ability of the power system to maintain and control the voltage waveform at a given location, both during steady state operation and following a disturbance. System strength is often approximated by the amount of electrical current available during a network fault (fault current), however the concept also encompasses a collection of broader electrical characteristics and power system interactions[6].

System strength supports the stable operation of network protection, voltage control devices, and IBR connections. Ensuring that sufficient system strength is available, and in the right locations, is vital to a stable, secure, and reliable power system that supports open and efficient investment.

Historically, system strength has been provided by thermal generators in well-connected parts of the network. As these units are replaced by renewable generation in other locations, it is increasingly difficult to accommodate new IBR investment while maintaining stable power system operation.

In October 2021, the NER were amended to drive more proactivity in the provision of system strength services, and to leverage the economies of scale and operational benefits of larger, centralised investments. The system strength framework is currently in transition between its previous and new incarnations, both of which apply in parallel until 1 December 2025.

System strength requirements

AEMO publishes a 10-year projection of system strength requirements each year. These requirements are expressed as two distinct components:

- **AEMO's forecast of minimum required three phase fault level** – intended to ensure that network protection and voltage control devices continue to operate correctly, even as traditional fault current sources withdraw from the system. This requirement is specified as a fault current and must therefore be met by devices capable of providing fault current, including synchronous condensers, contracts with existing units to provide synchronous services, or the retrofit of existing plant to become permanent system strength providers.
- **AEMO's optimised forecast of future IBR investment** – intended to drive sufficient system strength investment in strong, optimised network locations to accommodate future IBR connections. This is specified as an accommodated capacity and can therefore be met by any existing or new technology capable of improving the resilience of the local voltage waveform, including dynamic reactive devices or grid-forming inverter technology adaptable to the needs of a specific network location.

The System Strength Service Provider (SSSP) in each region has sole responsibility for assessing and delivering the services needed to meet both requirements within a rolling three-year window.

[6] AEMO. *System strength in the NEM explained*. March 2020, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/ssr/system-strength-explained.pdf?la=en.

More details on the nature of system strength requirements are available in the System Strength Requirements Methodology (SSRM)[7].

A1.3.2 Inertia

In the context of the power system, inertia describes an immediate, inherent, electrical response from connected devices that acts to oppose changes in frequency. Ensuring sufficient levels of inertia are available allows the power system to resist large changes in frequency that can arise following a contingency event, slowing the RoCoF and providing time for other automated control systems to respond[8].

Inertia is most often associated with synchronous machines, that have large spinning turbines and rotors whose rotation is synchronised to the frequency of the power system. These components are typically heavy, weighing tens or hundreds of tonnes, and can provide inertia from the kinetic energy associated with the rotating mass[9].

IBR are typically interfaced with the power system through electronic devices rather than electro-magnetic coupling, and do not typically provide inertia as an inherent characteristic[10]. However, it is possible for some IBR to provide an emulated inertial response through appropriate designs and controls. This is often referred to as fast frequency response (FFR), although FFR can represent a spectrum of services with differing response characteristics.

While synthetic inertia could theoretically replace the synchronous inertia in the NEM, there is not yet sufficient modelling or real-world experience available to quantify the implications and interactions of a system that is fully reliant on synthetic inertia and FFR providers. As such, it is likely that synchronous machines will remain a core component in meeting inertia requirements across the planning horizon.

Inertia requirements

Currently, AEMO publishes a five-year outlook of inertia requirements, projected availabilities, and expected inertia shortfalls each year. These shortfalls are assessed against two distinct inertia requirements:

- **A minimum threshold level of inertia**, 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, and
- **A secure operating level of inertia**, 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.

In assessing inertia shortfalls, AEMO calculates the inertia requirements for a given region with reference to maintaining the Frequency Operating Standard. AEMO then undertakes a suite of market modelling studies to estimate the typical levels of inertia expected in the region, where 'typical' refers to a 99th percentile availability.

Differences are then declared as inertia shortfalls, and the Inertia Service Provider[11] for each region has sole responsibility for delivering any required assets or services necessary to address the declared shortfall.

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[7] Version 2.0 of the SSRM is available on AEMO's website at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[8] For definitions and descriptions of inertia and power system security, please refer to AEMO's *Power System Requirements*, updated July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[9] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en.

[10] Some variable speed drive hydro units can also be inverter-interfaced and therefore do not provide a synchronous inertial response.

[11] As defined in NER 5.20B.4(a).

The 2024 ISF final determination moved the inertia obligations to align with the system strength timeframes and introduced a new 'NEM-wide inertia floor' that sits in parallel with existing islanding requirements[12].

A1.3.3 Network support and control ancillary services (NSCAS)

NSCAS are non-market services with the capability to control the active or reactive power flow into or out of a transmission network. They can be procured to address the following two categories of need[13]:

- **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 the 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. Under the ISF final rule, inertia network services and system strength can be procured under the NSCAS framework, effective 1 December 2024. The NER give TNSPs primary responsibility for acquiring NSCAS (with or without a declared gap), and AEMO may be required to procure NSCAS under its last resort planning functions.

Reliability and security ancillary services (RSAS)

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

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 in the annual NEM constraint report summary[14]. AEMO may also consider specific constraints nominated by participants or those forecast to be significant through other power system planning and operational activities, in alignment with the NSCAS description and quantity procedure[15].

A1.3.4 *General Power System Risk Review* (GPSRR)

AEMO undertakes the GPSRR annually for the NEM in consultation with NSPs. First published in July 2023, the GPSRR[16] replaces the biennial *Power System Frequency Risk Review* (PSFRR). It includes review and prioritisation of power system risks, events, and conditions that could lead to cascading outages or supply disruptions. The GPSRR also draws inputs from, and in turn informs and supports, a number of AEMO's related reports and processes, including the ISP.

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[12] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[13] NER Version 203, Clause 3.11.6 (a)(1), and NER Version 203, Clause 3.11.6 (a)(2)

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

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

[16] AEMO. *General Power System Risk Review*, July 2023, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2023-general-power-system-risk-review/2023-gpsrr.pdf?la=en.

For each priority risk, the GPSRR assesses the adequacy of current risk management arrangements. The GPSRR also reviews arrangements for managing existing protected events and considers any necessary changes or revocations. AEMO plans to publish the next GPSRR report by 31 July 2024.

A1.4 Projected outlook and opportunities

This section quantifies the adequacy of system security services under the *Step Change* scenario by comparing the expected levels of available services against the associated regional requirements at five-yearly increments.

The section is structured geographically to reflect the largely regional nature of investment obligations for system security services. This structure also makes it easier to identify any potential options for co-optimised investment to deliver multiple system security services from a single asset or provider.

Analysis scope and assumptions

In assessing the adequacy of system security services in this appendix, AEMO has considered the minimum levels of system strength as presented in the 2023 *System Strength Report* and the secure operating levels of inertia as described in the 2023 *Inertia Report*[17]. These requirements have been assumed to continue unchanged over the assessment period to 2039-40. In practice, these requirements may change over time.

RIT-Ts are already underway in every NEM region to deliver the first round of system strength investment by 2 December 2025. These may result in investments in new synchronous condensers or other security assets and services that address some of the needs presented in this appendix. However, given the quantity, design, timing and location of these possible investments are presently unknown, the underlying needs remain included in full for the projections in this section.

Results are presented for system strength and inertia studies for 2024-25, 2029-30, 2034-35 and 2039-40. The 2024-25 results come from the 2023 Inertia and System Strength reports. Results for 2029-30 onwards are from ISP modelling. Although AEMO projects that some new and existing shortfalls may arise in future, no inertia or system strength shortfalls are declared on the basis of results in this report.

The market modelling simulations that underpin these projections:

- Were based on *Step Change* scenario generator, storage and transmission build outcomes for the final 2024 ISP[18].
- Included generator dispatch projections from a time-sequential model using the ‘bidding behaviour model’ for realistic generator dispatch results given the generation and build outcomes[19].
- Applied bidding strategies that change to reflect greater uncertainties further out into the future. The 2024-25 projections used benchmarked competitive bidding, and projections from 2029-30 onwards used short run marginal cost bidding.
- Applied multiple generation outage patterns for the 2024-25 projections, but a single outage pattern for years 2029-30 onwards. This reflects the greater uncertainty in outcomes further into the future.

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

[18] Outcomes presented in this appendix are based on the ODP, which is CDP14 described in Appendix 6. Cost benefit analysis. However, the timing for VNI West is assumed to be 2034 in this appendix, whilst final ISP modelling times the project at 2030.

[19] Details for the bidding behaviour model are provided in AEMO’s Market Modelling Methodologies report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

- Modelled the Queensland and South Australia regions as islands for the Queensland and South Australia 2024-25 inertia projections, but modelled the mainland NEM intact for all inertia projections from 2029-30.

A1.4.1 NEM-wide outlook

Near-term outlook

In the 2023 system security reports[20], AEMO assessed emerging needs and shortfalls for system strength, inertia, and NSCAS in the near term:

- The 2023 *NSCAS Report* confirmed that existing NSCAS gaps in Queensland and New South Wales had been closed and declared new gaps in Victoria and South Australia. Several marginal or emerging risks were also identified and provided to relevant network businesses for further investigation.
- The 2023 *System Strength Report* confirmed the timing of existing shortfalls in Queensland, New South Wales, and Tasmania, but did not identify any new system strength shortfalls within the outlook period to 1 December 2025. Since the 2022 *System Strength Report*, the size of the shortfalls in New South Wales had increased, but the shortfalls in Tasmania had decreased. The size of the Queensland shortfall was unchanged.
- The 2023 *Inertia Report* confirmed that all declared inertia shortfalls for 2023-24 are currently being managed appropriately through network support agreements. The analysis did not identify any new inertia shortfalls, but the magnitude and timing of all previously declared shortfalls were revised. While inertia requirements had generally become more onerous to reflect the latest frequency standards and models, the expected levels of available inertia had improved, resulting in small deferrals or reductions to most shortfalls across the NEM.
- The 2023 *General Power System Risk Review* assessed four priority risks that could lead to cascading outages or major supply disruption. AEMO recommended actions for three of the four risks. These included recommendations concerning plant maintenance on the network in the Tamworth area, investigation and (if found viable) implementation of a new special protection scheme for the Queensland – New South Wales Interconnector (QNI), as well as continued collaboration between AEMO and TNSPs to ensure that the future South Australia Interconnector Trip Remedial Action Scheme (SAIT RAS) will operate effectively in conjunction with other protection schemes. AEMO also made several other recommendations regarding other risk mitigation measures, and one recommendation regarding the protected events framework.

The changes in shortfall size for both system strength and inertia results are largely driven by updated delivery timing for several major generation, transmission, and renewable energy zone (REZ) development projects. The net result has been a higher modelled utilisation of synchronous generation, resulting in a higher available inertia and fault current.

Long-term outlook

In the long term, trends for system security services are driven by the following phenomena:

- **Retiring coal-fired generation** – historically, coal-fired generation has been the source of the majority of the system strength and inertia in the NEM and a significant source of voltage control capability. As 90% of the current 21 gigawatts (GW) of coal capacity is projected to retire under the *Step Change* scenario by 2034-35, replacement services will need to be procured.

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

- **Increases in IBR development** – the *Step Change* scenario projects an additional 89 GW of IBR generation by 2039-40. Adequate system strength services will need to be procured to ensure this generation can stably operate. Some of these services will likely need to be provided by established technologies such as synchronous condensers. However, in the longer term AEMO expects that IBR with grid-forming inverters will also contribute system strength. Additionally, IBR generation dispersed across the NEM will provide new sources of voltage control capability.
- **Commissioning of major network augmentations such as new interconnectors** – new interconnectors help system strength and voltage control by lowering the system impedance. They will also reduce the likelihood of regions becoming islanded, which can reduce the need for inertia services.

Figure 2 below shows the projected decline in total inertia online in the mainland NEM to 2039-40 if no new investment in inertia provision were to occur[21]. It illustrates a general sharp downward trend in inertia over time, driven by declining coal-fired generation utilisation and retirements. The 99th percentile of inertia availability is projected to decline from 63,000 megawatt-seconds (MWs) in 2024-25 to 23,000 MWs in 2029-30.

Figure 2 Projected mainland NEM inertia, *Step Change* scenario (MWs)

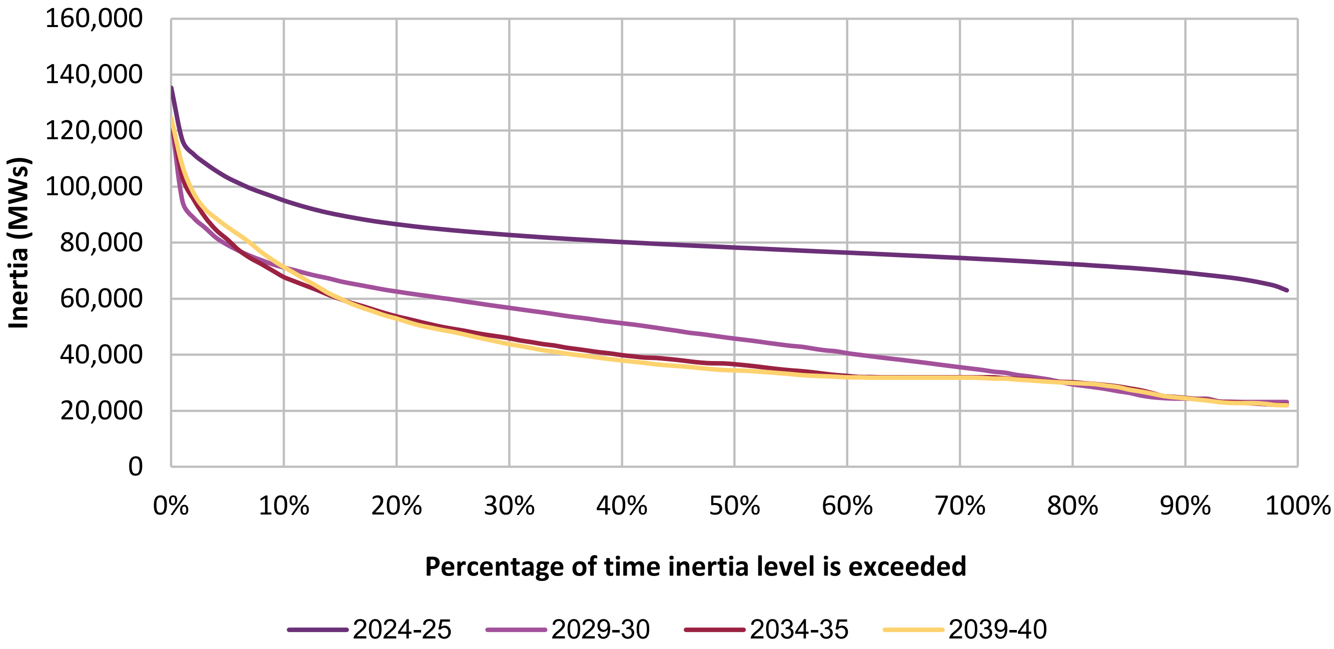


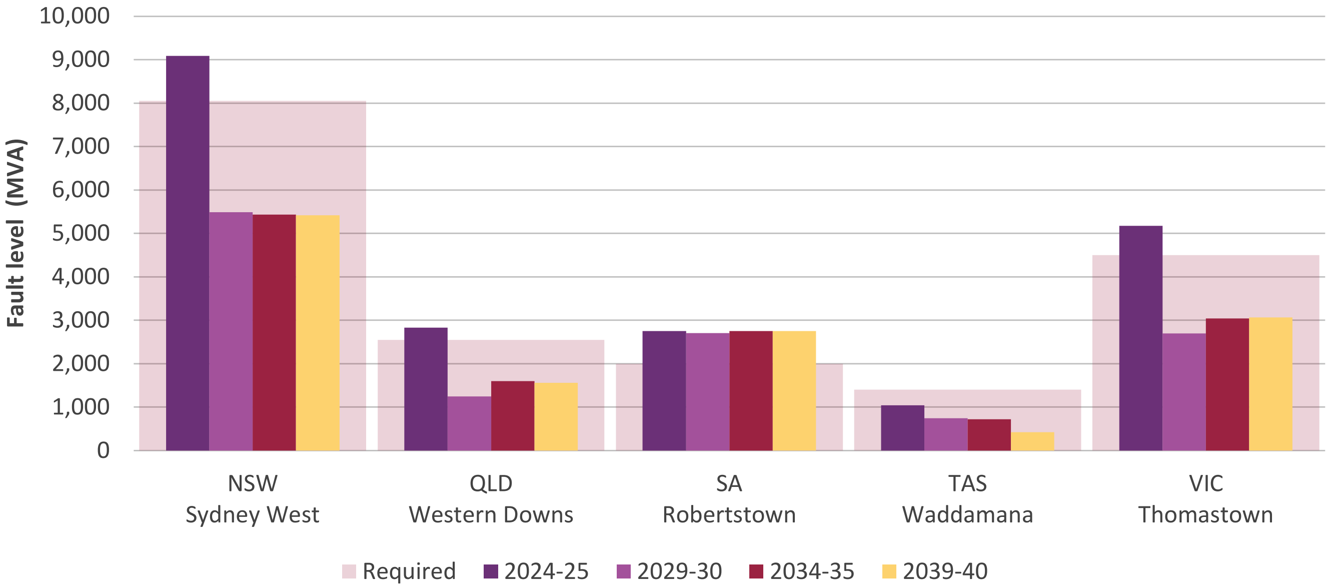
Figure 3 below shows the 99th percentile of synchronous fault level projected out to 2039-40 for a representative system strength node in each region, and highlights the following trends:

- **New South Wales, Queensland and Victoria** – 99th percentile fault levels generally decline sharply from 2024-25 to 2029-30, driven by closures and declining utilisation of thermal generation. The fault level values are generally stable from 2029-30 onwards, despite further plant closures in this period, because by 2029-30 there are already considerable periods with limited coal generators online, even before they formally retire.

[21] The modelling does account for generation, storage, and transmission built as part of the *Step Change* scenario, which may include some level of associated inherent inertia, but no specific investment for the purpose of inertia provision.

- **South Australia** – 99th percentile fault levels remain relatively stable from 2024-25 to 2039-40.
- **Tasmania** – 99th percentile fault levels decline from 2024-25 to 2039-40. Tasmania. The magnitude of this is driven primarily by growth in local IBR and changes in energy exports to the mainland, which combine to impact utilisation of local synchronous hydro generation. The reductions are not as severe as in other regions, because synchronous hydro generation in Tasmania remains sufficiently well-utilised in support of energy exports to the mainland.

Figure 3 Fault level projections and requirements at representative nodes in each region (megavolt-amperes (MVA))



Estimated cost of security remediation

AEMO has prepared high-level cost estimates for provision of system strength services in each REZ across the NEM. System strength service requirements are based on assessment of existing synchronous generation dispatch, potential network upgrades, and the potential scale of local IBR.

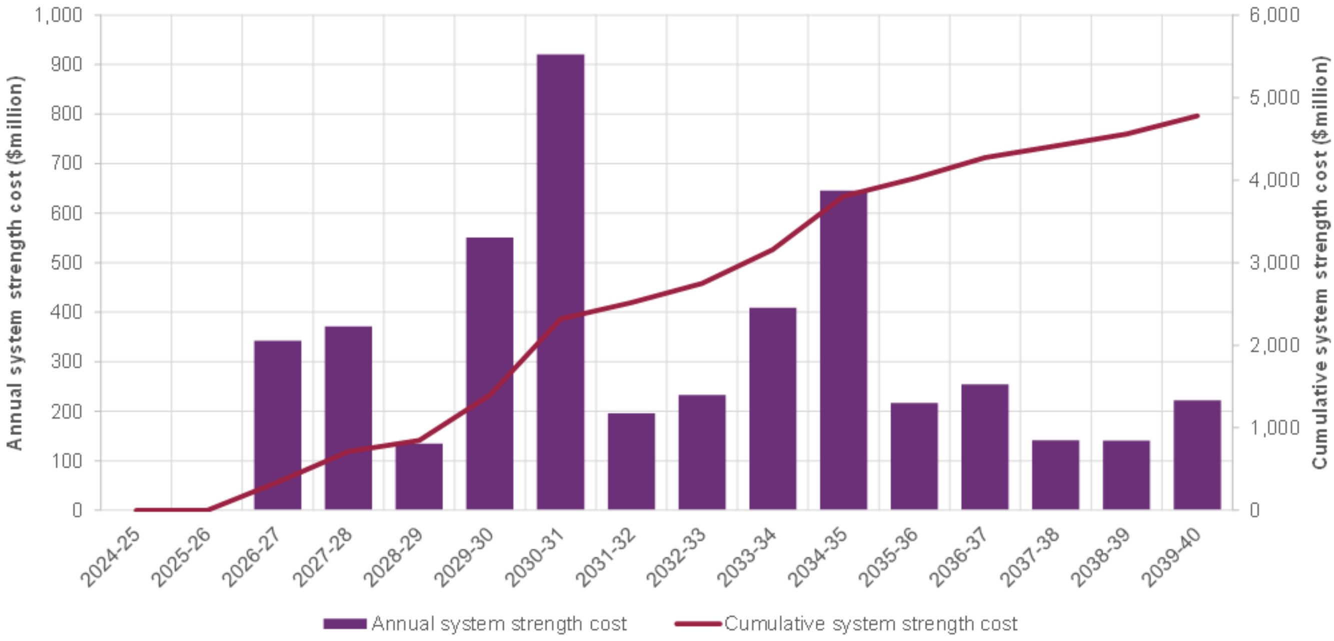
AEMO has estimated costs based on synchronous condenser technology, as an existing, commercially viable, technology that has been demonstrated at scale and is capable of meeting both the minimum and efficient system strength requirements.

Over time, AEMO expects that alternative technologies such as grid-forming inverters will be become available to provide system strength services following adequate demonstration at scale. The cost estimates presented here are likely to represent an upper bound of system strength cost.

Figure 4 shows the cumulative system strength remediation costs to address system strength remediation for variable renewable energy (VRE) projected under the *Step Change* scenario across the NEM. These estimates assume a cost of $137,000 per megawatt (MW) as a baseline[22]. Approximately $4.8 billion is required to 2039-40 for system strength remediation for the forecast IBR generation connection in REZs.

[22] AEMO. 2023 IASR Assumptions Workbook, September 2023, at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en.

Figure 4 Projected system strength remediation costs by REZ, *Step Change* scenario ($/million)



AEMO has also considered high level cost estimates for provision of inertia services across the NEM based on deficits identified in each region. AEMO has estimated costs based on the incremental cost of fitting high inertia flywheels to synchronous condensers, as an existing, commercially viable, technology that has been demonstrated at scale. This is estimated at $1,818/MWs[23].

In March 2024, the AEMC extended the inertia framework to include a mainland inertia floor (the 'system-wide inertia level'), which will come into effect 1 December 2024[24]. AEMO has determined a possible cost of inertia services to maintain a hypothetical NEM-wide inertia floor. In the absence of specific methodology to calculate the floor at this stage, AEMO has assumed a hypothetical inertia target of the sum of all the regional secure operating level requirements (approximately 55,000 MWs)[25].

By 2039-40, AEMO's regional projections indicate a combined deficit of approximately 34,900 MWs across all regions against this hypothetical target. To fully meet this deficit through flywheel investments would cost approximately $64 million, spread across 32 to 35 high inertia flywheel investments.

The new requirement exists in parallel with a modified framework to ensure security under islanded conditions. The *Step Change* scenario projects approximately 17,000 MWs of cumulative inertia deficits out to 2039-40 in regions likely to island (Queensland, South Australia until the commissioning of PEC Stage 2, and Tasmania). It would cost approximately $30 million to fill these deficits by adding high inertia flywheels to synchronous condensers (where such synchronous condensers were already required to be built for system strength or other purposes).

[23] Cost based on $2 million per 1,100 MWs high inertia flywheel. See AEMO's 2023 *Transmission Expansion Options Report*, September 2023, Section 5.2, at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-transmission-expansion-options-report.pdf?la=en.

[24] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

[25] AEMO will be publishing a draft Inertia Requirements Methodology and associated Consultation Paper to reflect the AEMC's ISF final rule. This will include a methodology to set and allocate the inertia floor.

Not all system strength needs will be met using synchronous equipment, and therefore it is unlikely that the total volume of inertia needs would be met by flywheel-type investments. AEMO notes that other sources of inertia services are also possible, such as contracting with synchronous generators, and a potentially greater role for synthetic inertia from IBR. Under the new inertia framework, TNSPs will be allowed to procure synthetic inertia to meet minimum inertia levels, subject to AEMO's approval.

Importance of proactive and coordinated planning

AEMO assesses system strength, inertia and NSCAS gaps separately across corresponding annual reports. Each of these reports conducts analysis at a regional level. However, there could be efficiency gains in designing solutions holistically to fill gaps for multiple services or regions.

For example, RIT-Ts are underway in every NEM region to optimise across all available technology options, and to deliver the first round of system strength investment by 2 December 2025. These system strength investments may also provide an opportunity to supplement regional inertia levels using the same technical resource and with minimal incremental cost. For example, flywheels could be added to new synchronous condensers, while FFR services may be available from grid-forming batteries.

To support co-optimised investment, the AEMC aligned the existing inertia and system strength frameworks procurement timeframes under the 2024 ISF final rule[26]. This alignment is intended to allow TNSPs to better deliver and coordinate system security investment opportunities.

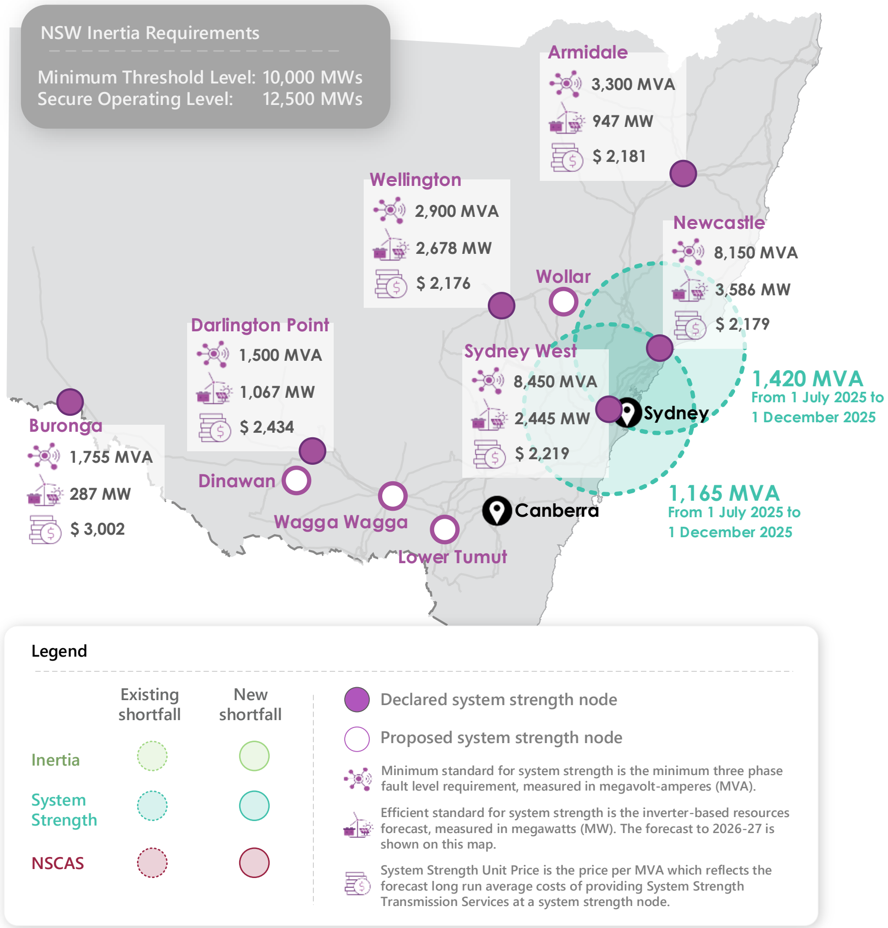
Well coordinated joint planning between AEMO, NSPs and jurisdictional bodies will be required to make investments that address identified gaps most efficiently. This joint planning process must recognise that timing solutions to meet identified shortfalls 'just in time' carry an inherent risk associated with project lead time uncertainty. Given the critical nature of maintaining system security and reliability, AEMO considers it prudent to plan the delivery of system security infrastructure ahead of when shortfalls are expected to occur.

[26] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

A1.4.2 New South Wales

System strength outlook – synchronous fault levels

System strength requirements (pre/post contingent)



Key results

Projected closure of coal-fired generation and declining utilisation of others is expected to reduce the synchronous fault level at some nodes.

At other nodes, this decline is offset by network expansions such as the Sydney Ring North.

Most projected need for fault current remediation occurs by the end of the decade.

Projected shortfalls against current minimum requirements

Node	Shortfall against minimum requirement				Trends
	2024-25	2029-30	2034-35	2039-40	
Armidale 330 kilovolts (kV)	0 MVA	0 MVA	150 MVA	182 MVA	Network expansions are projected to increase maximum fault level and offset decline.
Newcastle 330 kV	0 MVA	1,803 MVA	1,872 MVA	1,889 MVA	Fault levels expected to fall sharply over this decade (shortfalls declared from July 2025 in 2023 *System Strength Report*), with smaller decreases after 2030.
Sydney West 330 kV	0 MVA	2,564 MVA	2,618 MVA	2,634 MVA	
Wellington 330 kV[27]	0 MVA	0 MVA	0 MVA	5 MVA	Increased time spent near minimum.
Darlington Point 330 kV	0 MVA	0 MVA	0 MVA	0 MVA	No significant change.

[27] 2039-40 results for Wellington 330 kV are extracted from the Draft 2024 ISP.

Projected vs required level of fault current available at least 99% of the time

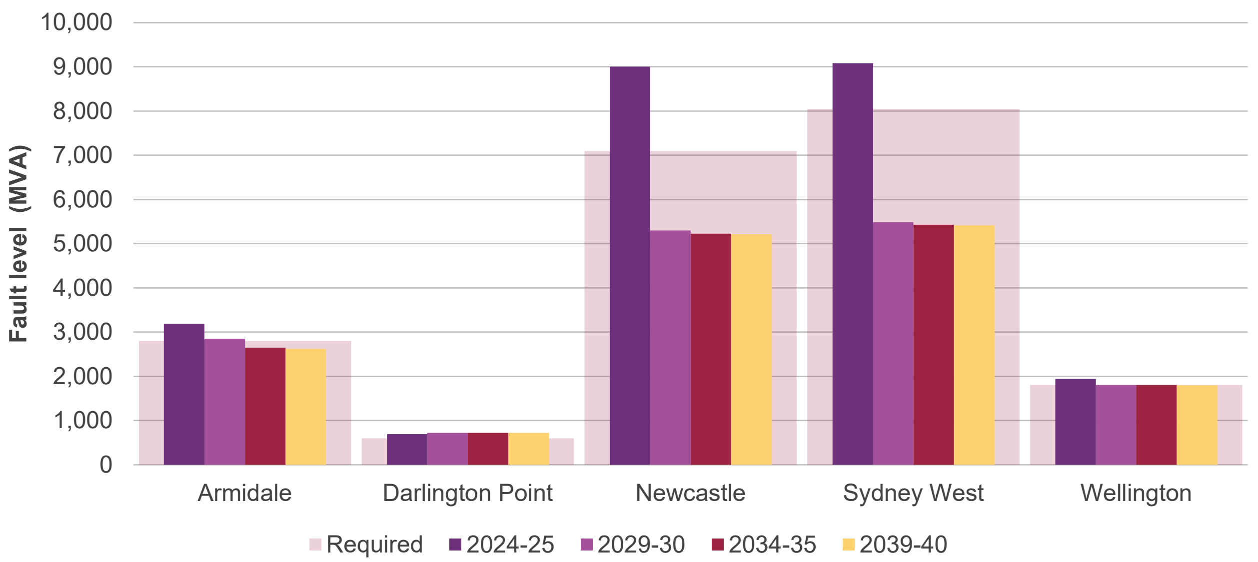
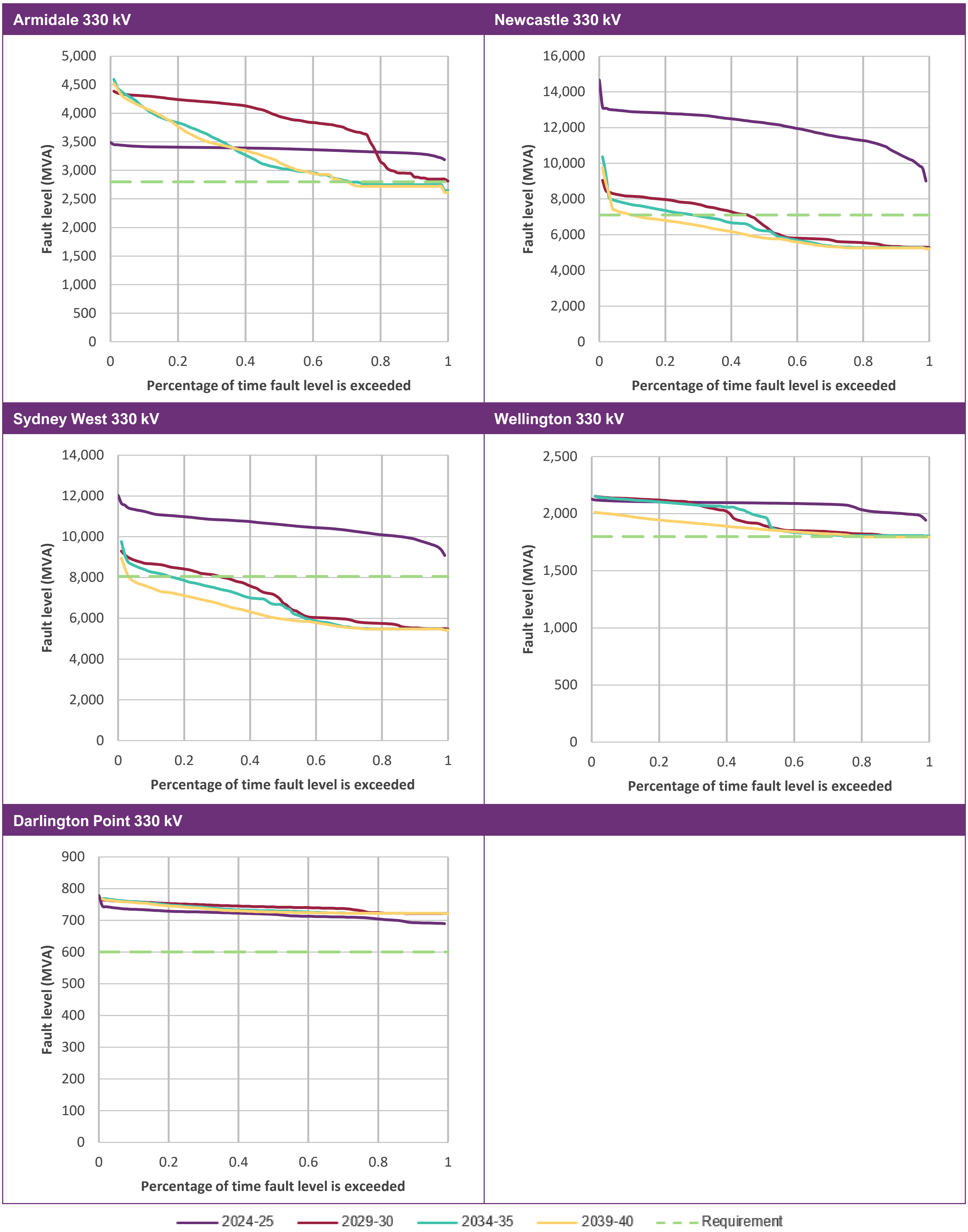


Figure 5 Percentage of time fault level is exceeded in New South Wales



System strength outlook – new IBR investment

Figure 6 IBR projections for New South Wales in 2024-25, 2029-30, 2034-35, and 2039-40 (MW)

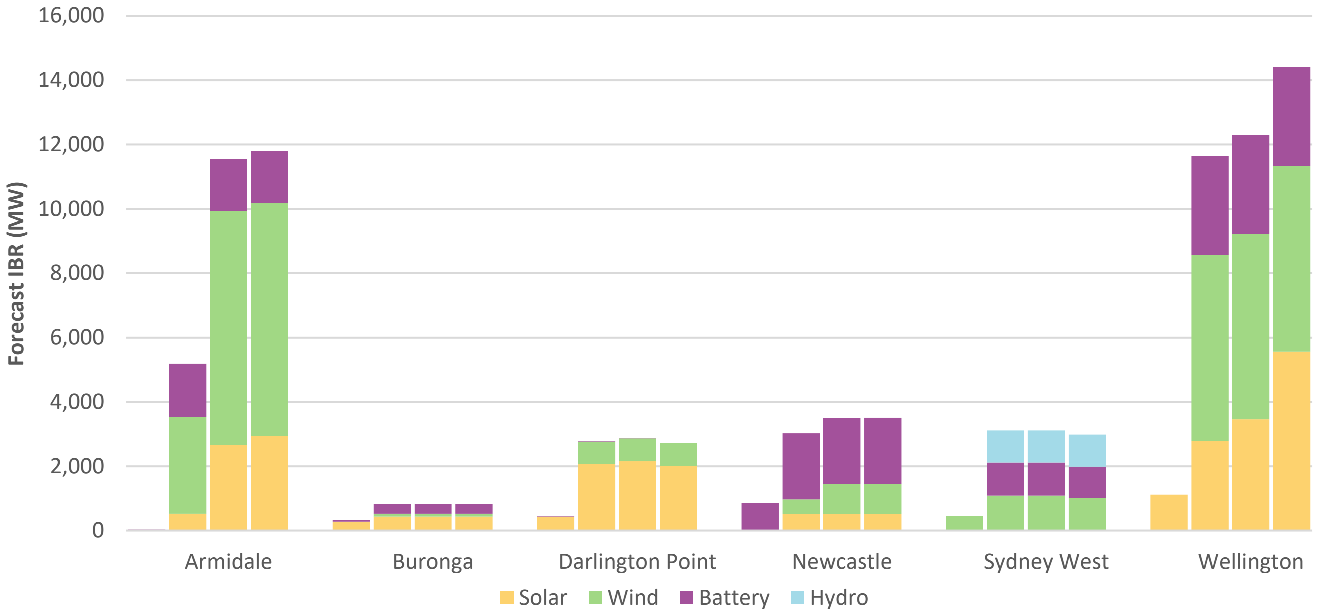


Table 1 IBR projections for New South Wales (MW)

Node	Technology	Existing	2024-25	2029-30	2034-35	2039-40
Armidale	Solar	521	0	530	2,663	2,950
	Wind	442	0	3,010	7,275	7,228
	Battery	0	30	1,645	1,615	1,615
Buronga	Solar	258	283	434	434	434
	Wind	199	0	93	93	93
	Battery	0	50	300	300	300
Darlington Point	Solar	1,368	436	2,063	2,159	2,009
	Wind	0	0	705	705	705
	Battery	150	10	10	10	10
Newcastle	Solar	0	0	516	516	516
	Wind	0	0	456	928	938
	Battery	0	850	2,053	2,053	2,053
Sydney West	Solar	10	0	0	0	0
	Wind	1,328	454	1,084	1,084	1,008
	Battery	160	0	1,031	1,031	981
	Hydro	0	0	1,000	1,000	1,000
Wellington	Solar	931	1,117	2,792	3,455	5,564
	Wind	400	0	5,774	5,774	5,774
	Battery	0	0	3,070	3,070	3,070

Inertia outlook

Key inertia results

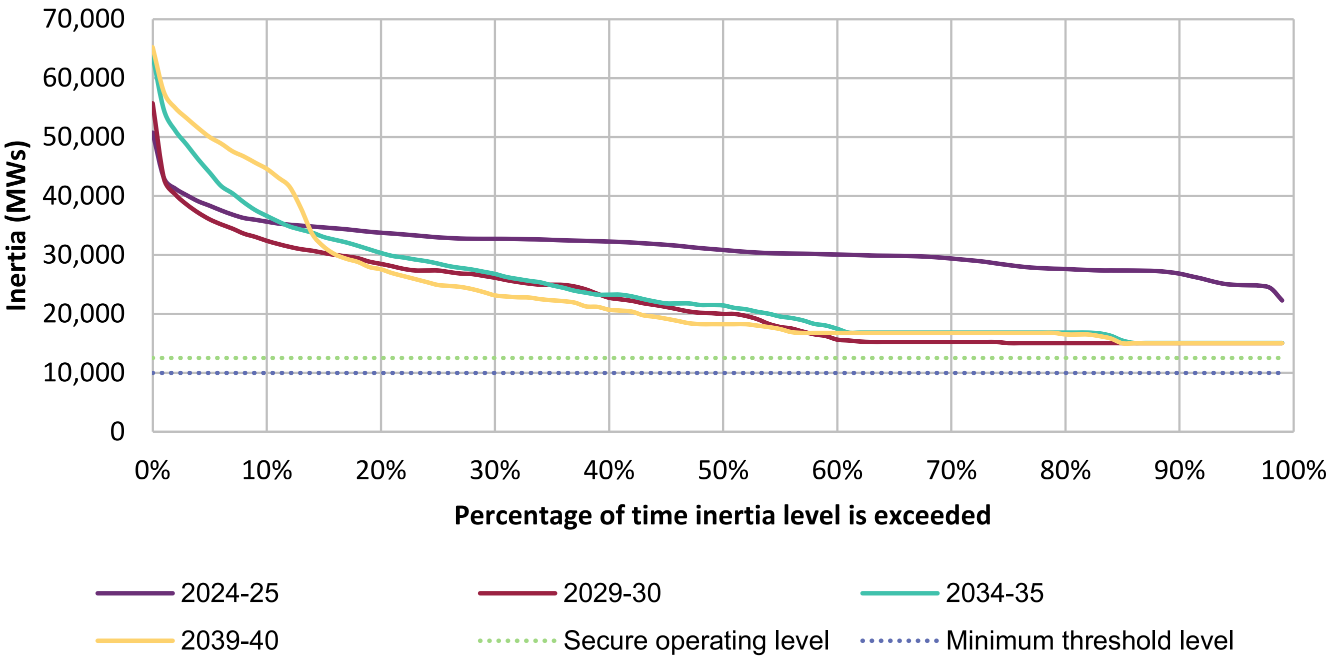
AEMO has not identified any inertia deficits out to 2039-40.

Inertia levels are largely consistent with the Draft 2024 ISP but have increased compared with the 2022 ISP. Inertia deficits identified in the 2022 ISP are no longer apparent. However, there is no change in the likelihood of declaring inertia shortfalls, as New South Wales is unlikely to island.

Table 2 Inertia outlook for New South Wales

Inertia projections				
	2024-25	2029-30	2034-35	2039-40
Minimum threshold of inertia (MWs)	10,000	10,000	10,000	10,000
Secure operating level of inertia (MWs)	12,500	12,500	12,500	12,500
Inertia available 99% of the time (MWs)	22,295	15,050	15,050	15,050
Calculated inertia deficit (MWs)	0	0	0	0
Likelihood of islanding	Unlikely	Unlikely	Unlikely	Unlikely

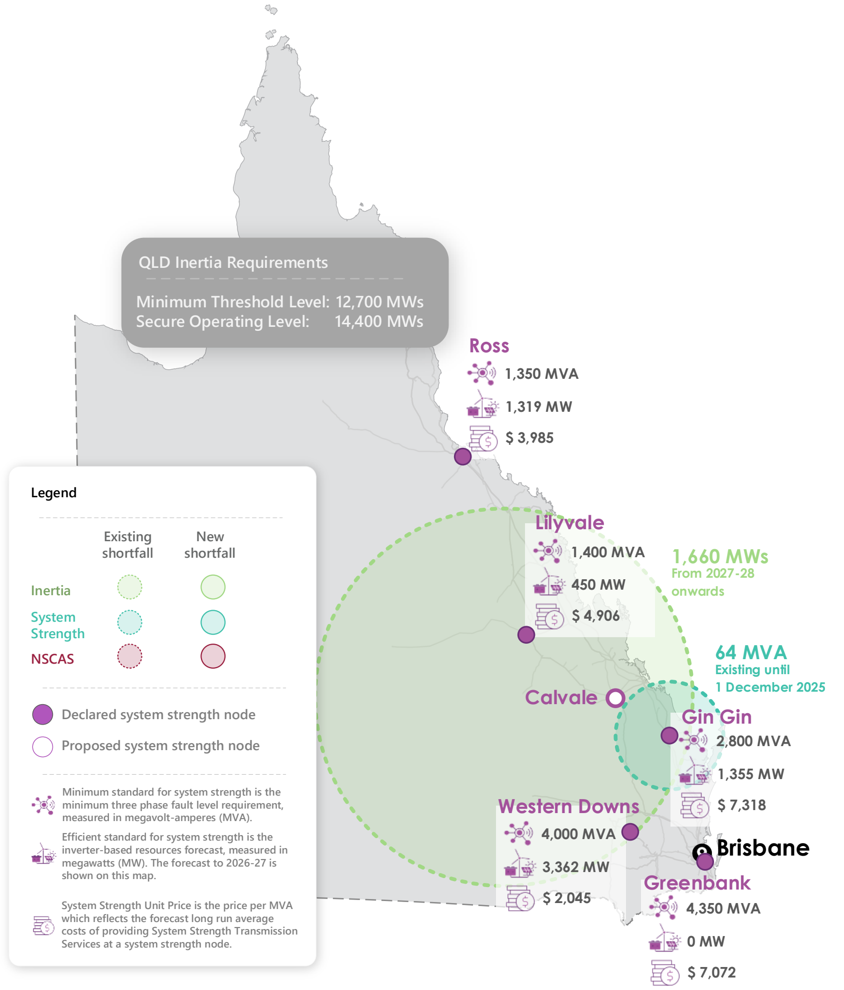
Figure 7 Projected levels of inertia available in New South Wales, *Step Change* scenario (MWs)



A1.4.3 Queensland

System strength outlook – synchronous fault levels

System strength requirements (pre/post contingent)



Key results

Projected closure of coal-fired generation in Queensland and declining utilisation of the remaining synchronous generators are expected to result in significant reductions in synchronous fault current.

Most of the projected need for fault current remediation occurs by the end of the decade.

Projected shortfalls against current minimum requirements

Node	Shortfall against minimum requirement				Trend
	2024-25	2029-30	2034-35	2039-40	
Gin Gin 275 kV	49 MVA	1,054 MVA	1,192 MVA	1,218 MVA	The synchronous fault current at all nodes is expected to fall sharply over the decade, but further reductions are not expected over the remaining planning horizon.
Greenbank 275 kV	0 MVA	2,141 MVA	2,246 MVA	2,283 MVA	
Lilyvale 132 kV	0 MVA	350 MVA	413 MVA	434 MVA	
Ross 275 kV	0 MVA	258 MVA	321 MVA	401 MVA	
Western Downs 275 kV	0 MVA	1,307 MVA	954 MVA	991 MVA	

Projected vs required level of fault current available at least 99% of the time

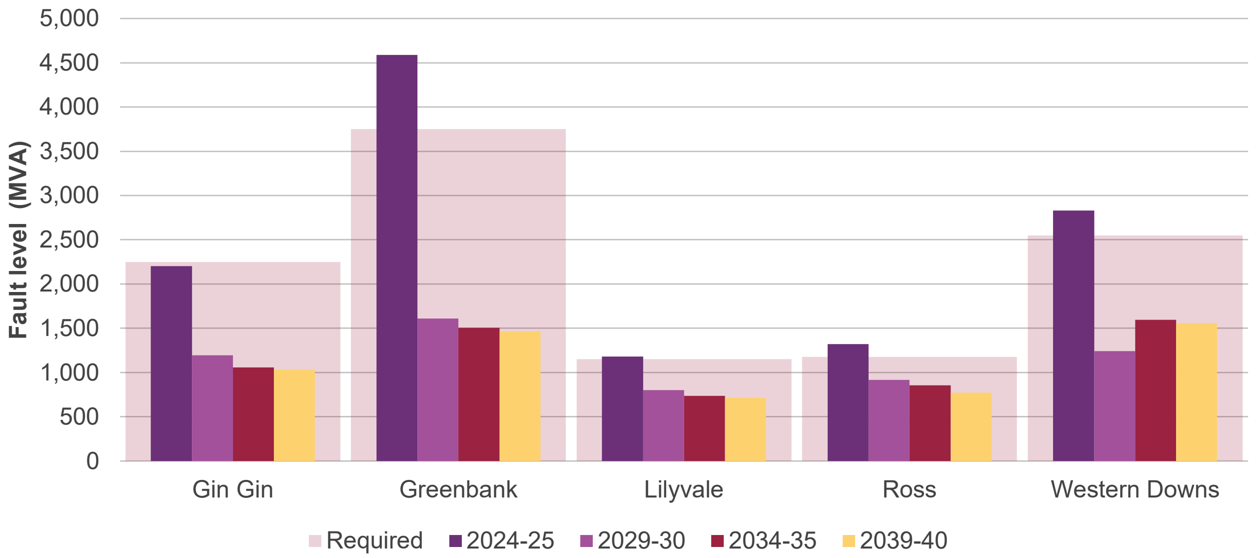
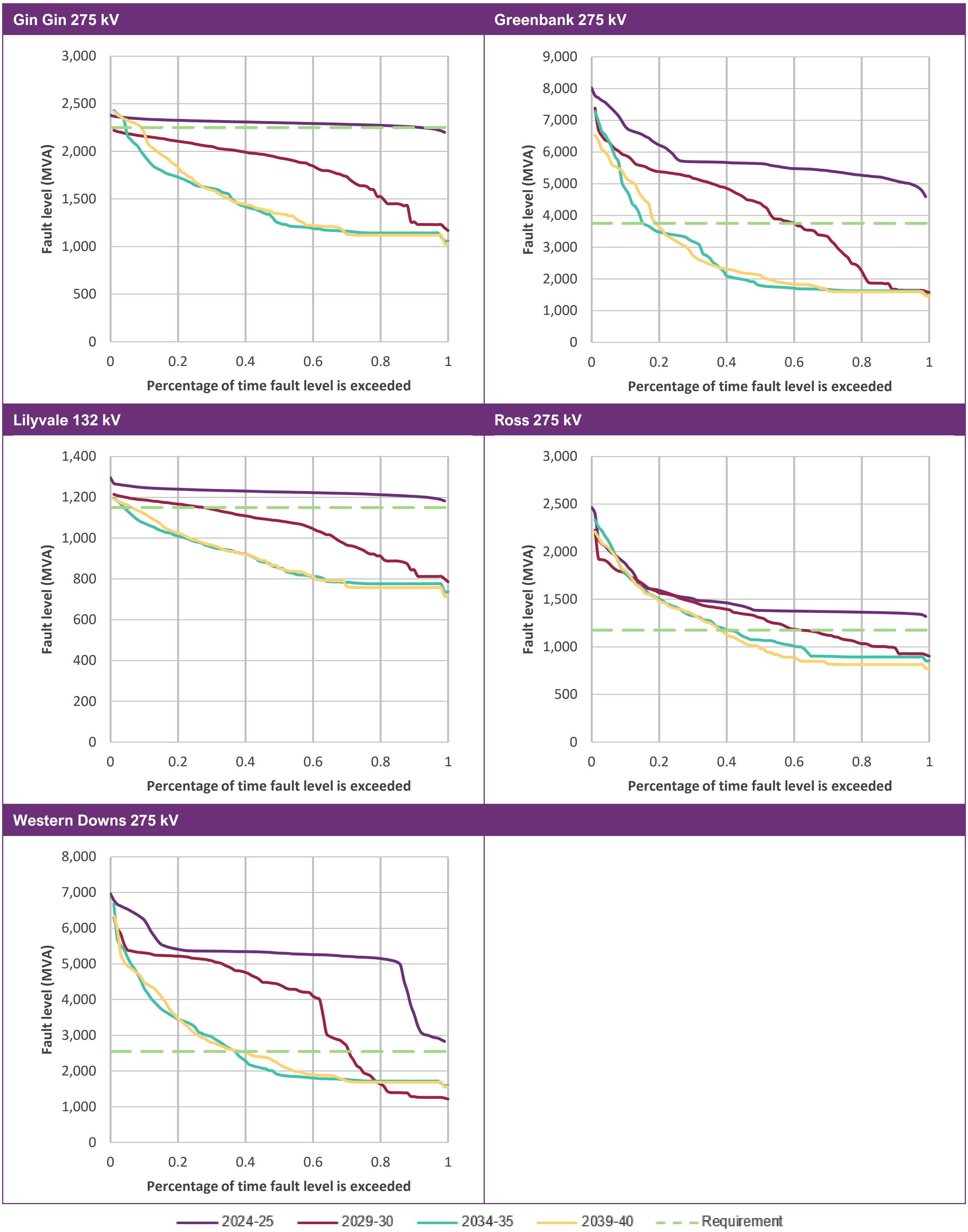


Figure 8 Percentage of time fault level is exceeded at each system strength node in Queensland



System strength outlook – new IBR investment

Figure 9 IBR projections for Queensland in 2024-25, 2029-30, 2034-35, and 2039-40 (MW)

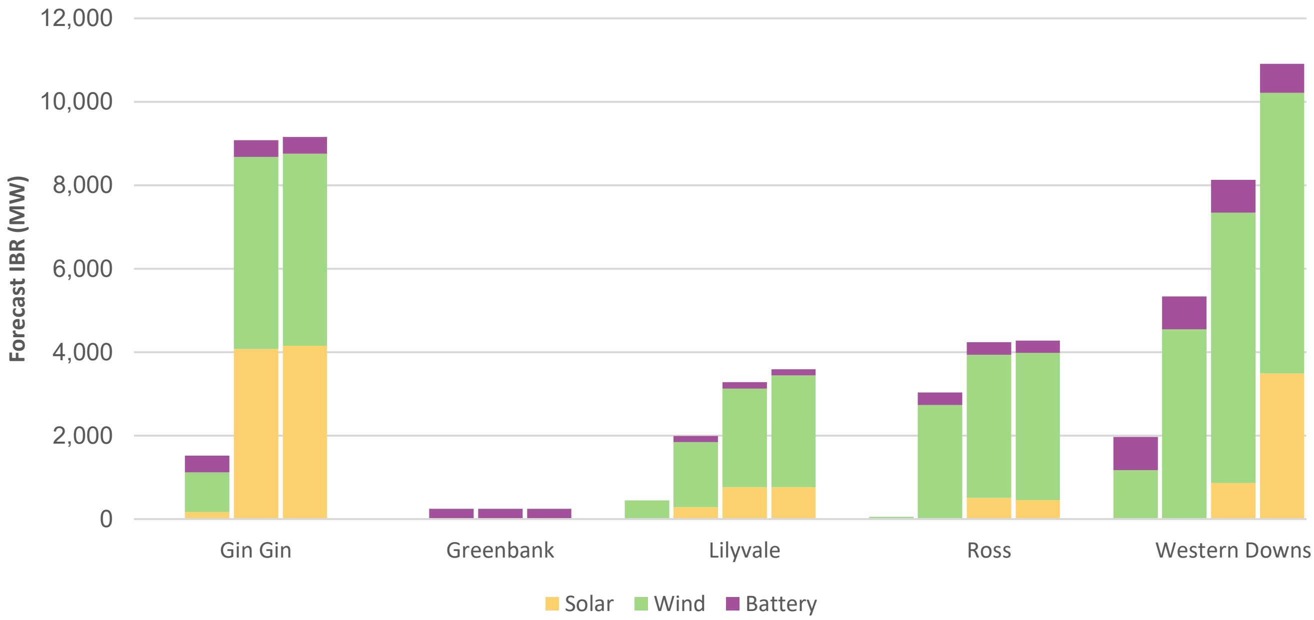


Table 3 IBR projections for Queensland (MW)

Node	Technology	Existing	2024-25	2029-30	2034-35	2039-40
Gin Gin	Solar	471	0	172	4,080	4,157
	Wind	0	0	950	4,600	4,600
	Battery	50	0	400	400	400
Greenbank	Solar	0	0	0	0	0
	Wind	0	0	0	0	0
	Battery	0	0	250	250	250
Lilyvale	Solar	389	0	288	769	769
	Wind	0	450	1,556	2,362	2,675
	Battery	0	0	150	150	150
Ross	Solar	968	15	15	510	460
	Wind	337	43	2,722	3,431	3,523
	Battery	0	0	300	300	300
Western Downs	Solar	1,671	0	0	869	3,493
	Wind	626	1,175	4,549	6,472	6,727
	Battery	200	791	791	791	691

Inertia outlook

Key inertia results

Inertia levels are predominantly consistent with the Draft 2024 ISP, with slightly lower inertia deficits are projected across the 20-year horizon.

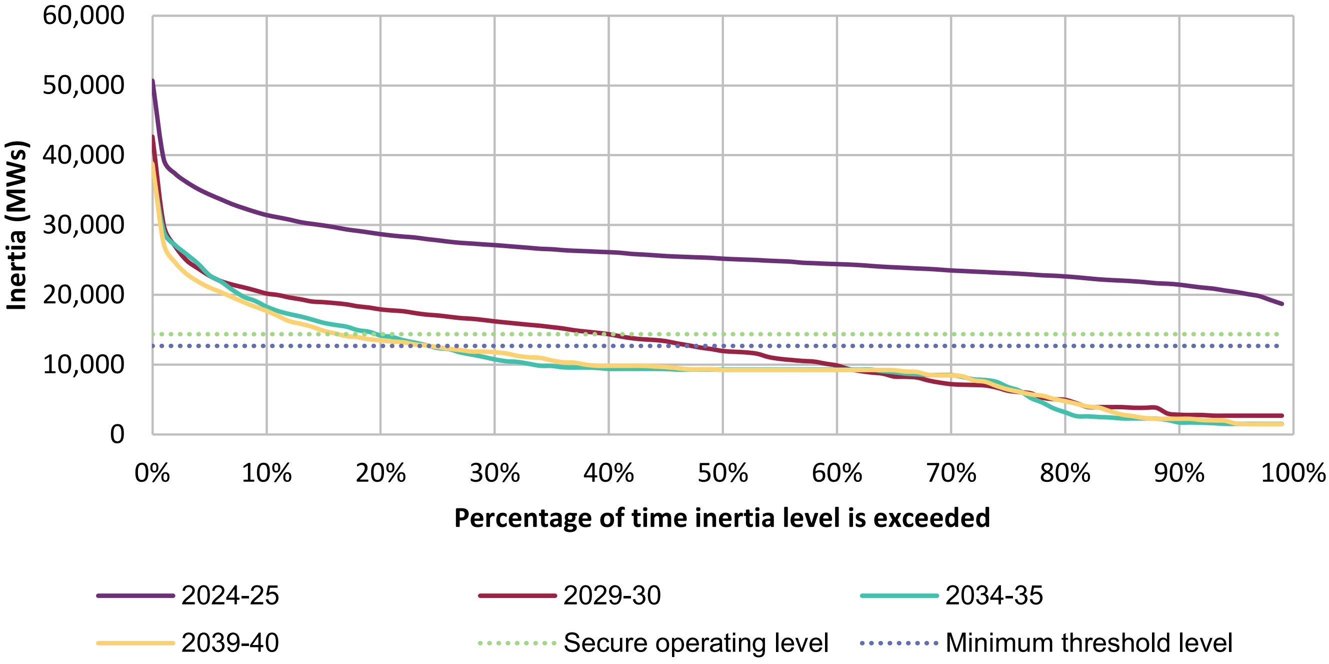
In the 2023 *Inertia Report*, AEMO declared an inertia shortfall of up to 1,660 MWs from 2027-28. Final ISP modelling over the 2029-30 to 2039-40 horizon identified larger inertia deficits throughout this period also. AEMO also notes that studies from 2029-30 onward did not model Queensland as an island, which likely leads to lower inertia than would otherwise be the case.

The final *Step Change* scenario models the QNI Connect project as commissioning in 2034-35, however AEMO has still classified the likelihood of islanding as "likely" in 2034-35, as there may not be sufficient route diversity with the existing QNI to rule out a plausible event such as flooding or bushfire from separating both flow paths and islanding Queensland. This assessment may change upon more detailed plans for the project being determined.

Table 4 Inertia outlook for Queensland

Inertia projections				
	2024-25	**2029-30**	**2034-35**	**2039-40**
Assumed level of 1-second FCAS (MW)	60	60	60	60
Minimum threshold of inertia (MWs)	12,700	12,700	12,700	12,700
Secure operating level of inertia (MWs)	14,400	14,400	14,400	14,400
Inertia available 99% of the time (MWs)	18,731	2,690	1,560	1,494
Calculated inertia deficit (MWs)	0	11,710	12,840	12,906
Likelihood of islanding	Likely	Likely	Likely	Likely

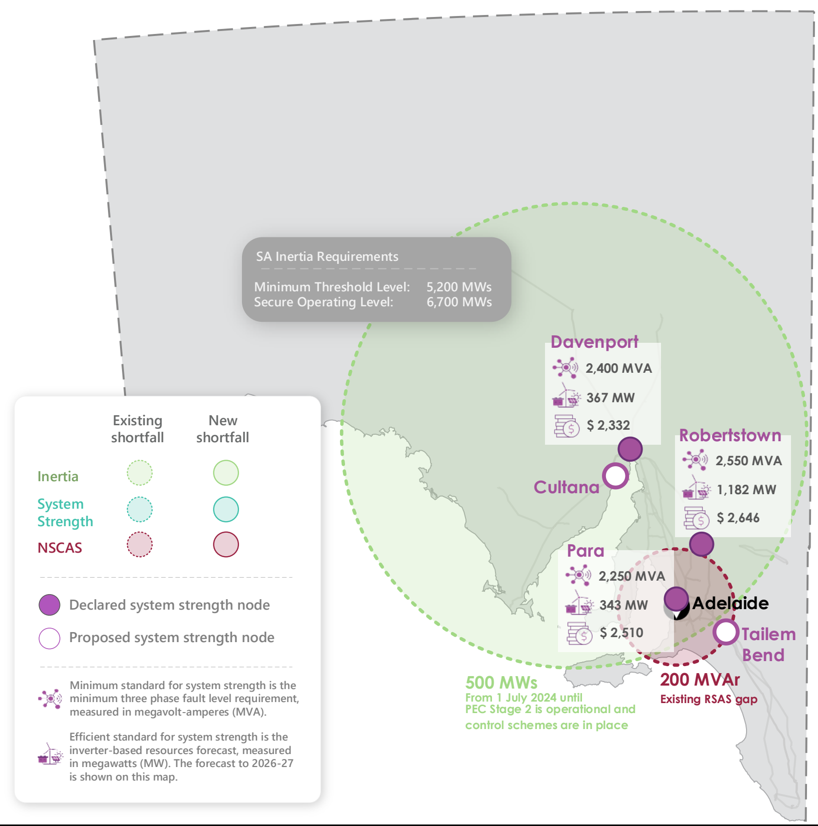
Figure 10 Projected levels of inertia available in Queensland, *Step Change* scenario (MWs)



A1.4.4 South Australia

System strength outlook – synchronous fault levels

System strength requirements (pre/post contingent)



Key results

With the four new synchronous condensers installed in South Australia, projected system strength remains adequate to meet current minimum fault level requirements.

Projected shortfalls against current minimum requirements

Node	Shortfall against minimum requirement				Trend
	2024-25	2029-30	2034-35	2039-40	
Davenport 275 kV	0 MVA	0 MVA	0 MVA	0 MVA	No significant changes
Para 275 kV	0 MVA	0 MVA	0 MVA	0 MVA	No significant changes
Robertstown 275 kV	0 MVA	0 MVA	0 MVA	0 MVA	No significant changes

Projected vs required level of fault current available at least 99% of the time

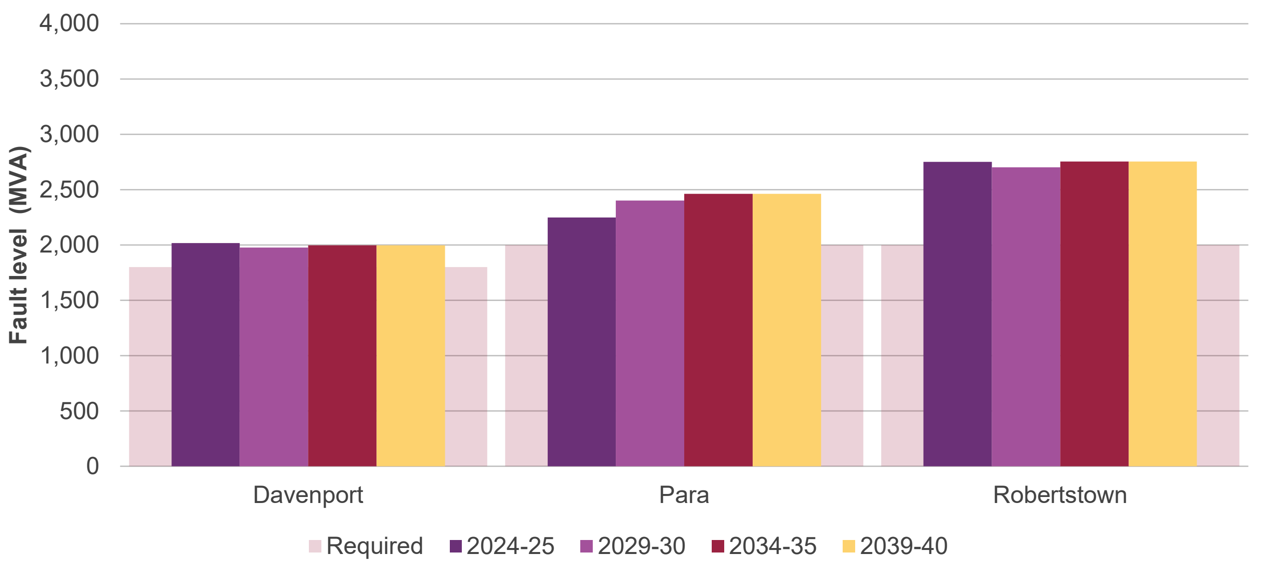
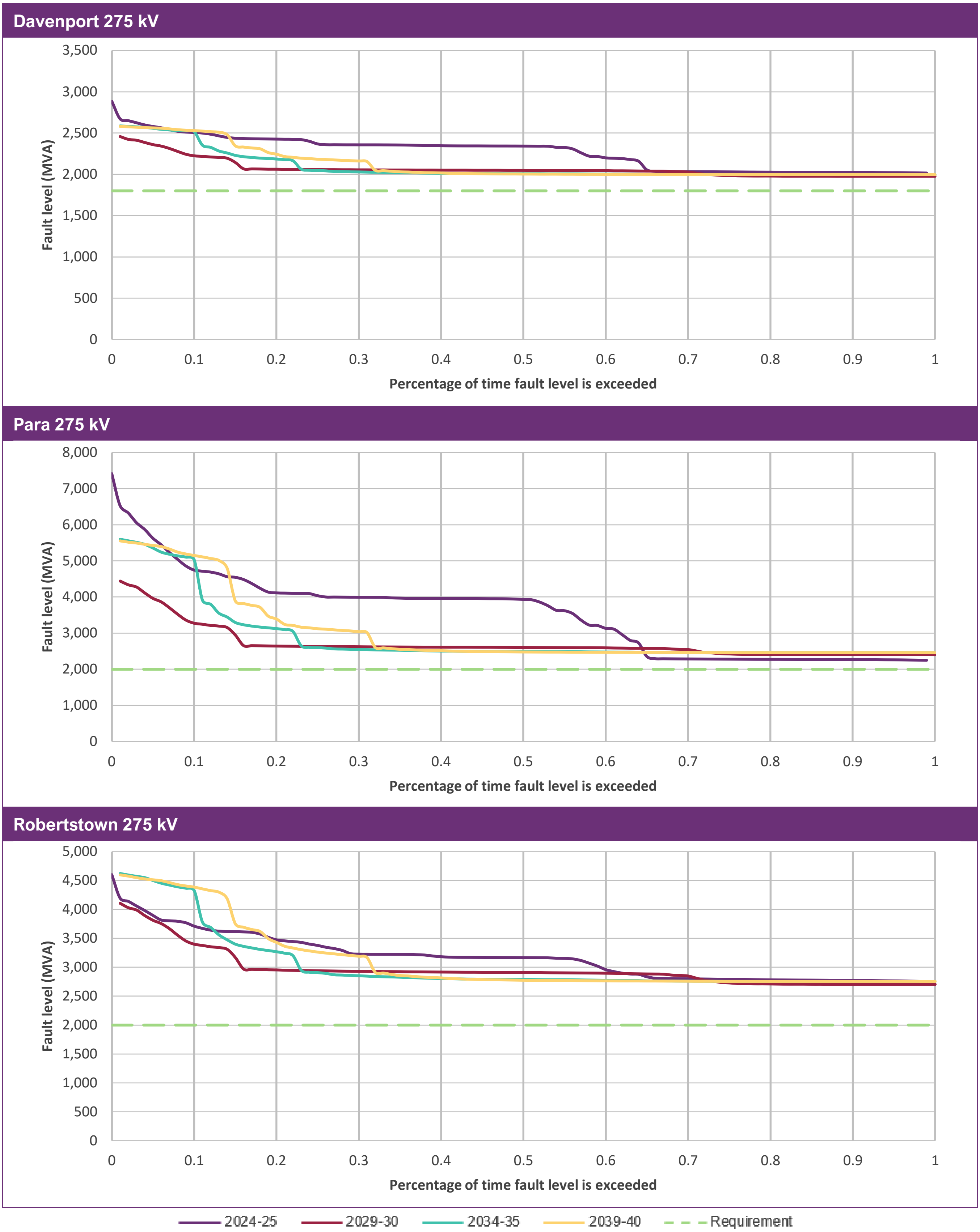


Figure 11 Percentage of time fault level is exceeded at each system strength node in South Australia



System strength outlook – new IBR investment

Figure 12 IBR projections for South Australia in 2024-25, 2029-30, 2034-35, and 2039-40 (MW)

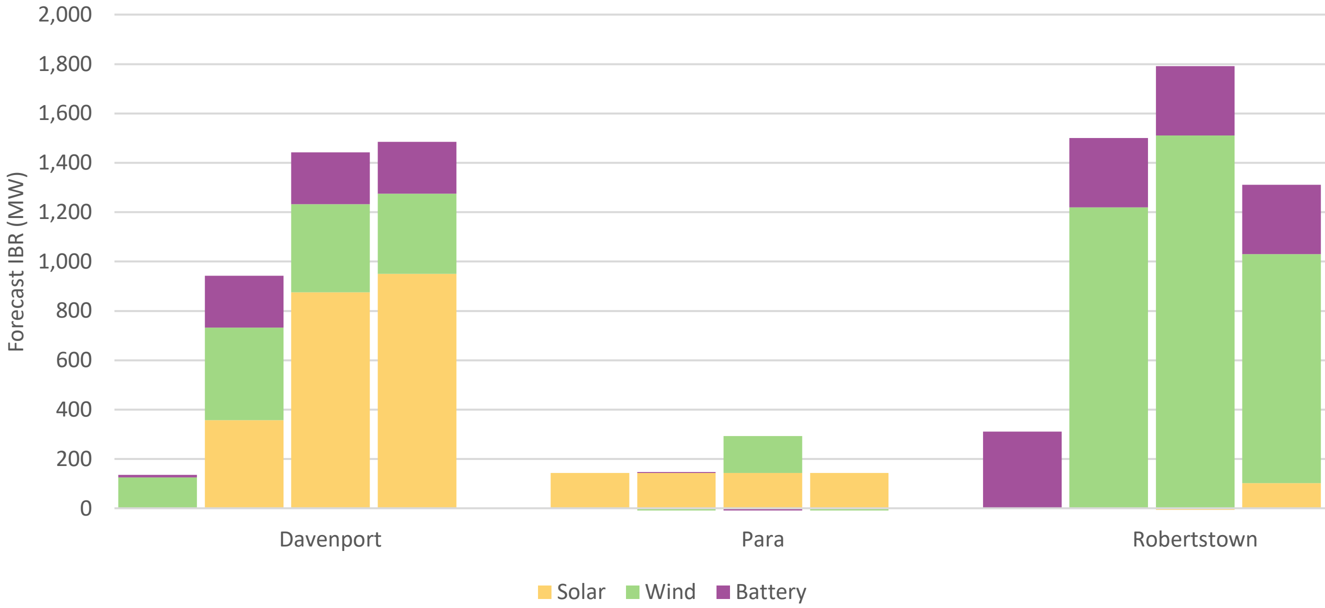


Table 5 IBR projections for South Australia (MW)

Node	Technology	Existing	2024-25	2029-30	2034-35	2039-40
Davenport	Solar	349	0	357	876	950
	Wind	431	126	376	357	326
	Battery	0	10	210	210	210
Para	Solar	173	143	143	143	143
	Wind	358	0	-33	150	-75
	Battery	323	0	4	-21	-21
Robertstown	Solar	25	0	0	-6	102
	Wind	1,846	0	1,220	1,511	928
	Battery	180	311	281	281	281

Inertia outlook

Key inertia results

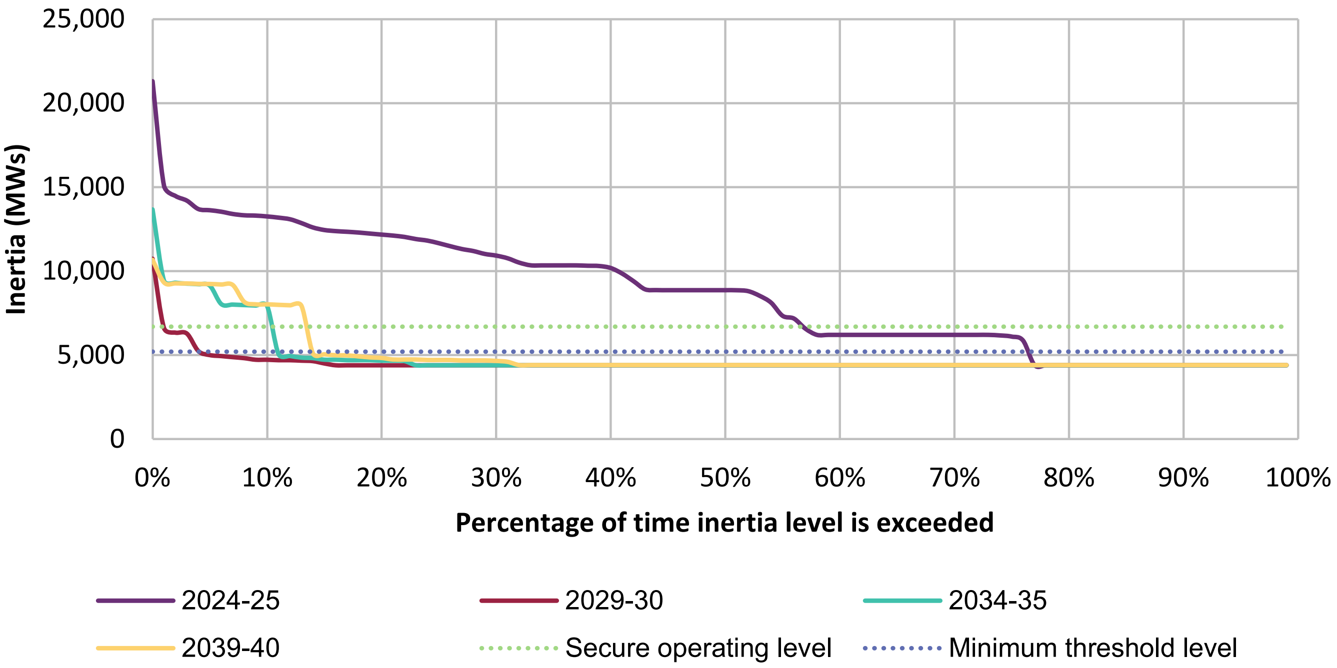
AEMO identified inertia deficits in each of the studied years, consistent with the Draft 2024 ISP. In the 2023 *Inertia Report*, AEMO declared an inertia shortfall of 500 MWs from July 2024 until PEC Stage 2 is complete, with necessary protection schemes in place to manage the non-credible loss of either PEC itself or the Heywood interconnector. After this point AEMO does not anticipate future declarations of inertia shortfalls, as South Australia will be unlikely to island.

Table 6 Inertia outlook for South Australia

Inertia projections				
	2024-25	**2029-30**	**2034-35**	**2039-40**
Assumed level of 1-second FCAS (MW)	240	240	240	240
Minimum threshold of inertia (MWs)	5,200	5,200	5,200	5,200
Secure operating level of inertia (MWs)	6,700	6,700	6,700	6,700
Inertia available 99% of the time (MWs)	6,200	4,400	4,400	4,400
Calculated inertia deficit (MWs)	500	2,300	2,300	2,300
Likelihood of islanding	Likely[A]	Unlikely[A]	Unlikely[A]	Unlikely[A]

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

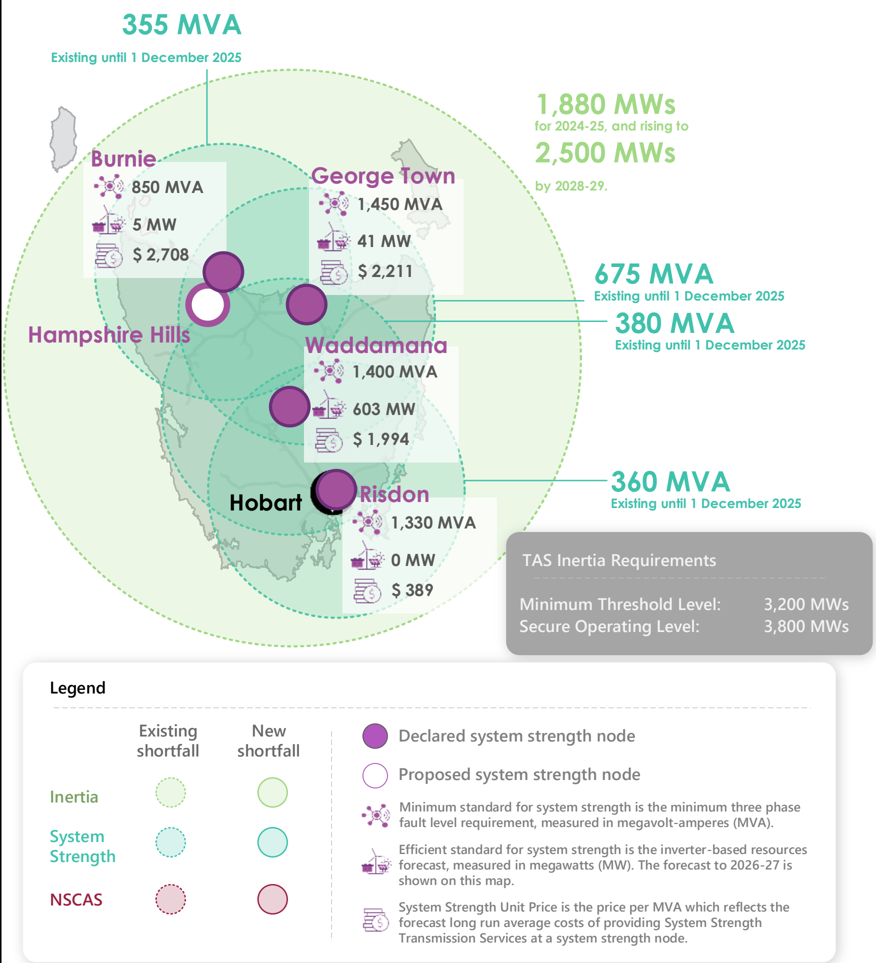
Figure 13 Projected levels of inertia available in South Australia, *Step Change* scenario (MWs)



A1.4.5 Tasmania

System strength outlook – synchronous fault levels

System strength requirements (pre/post contingent)



Key results

Shortfalls are likely to occur across the outlook period in Tasmania without additional system strength services.

Shortfalls are currently managed through contracted services until April 2024.

Projected shortfalls against current minimum requirements

Node	Shortfall against minimum requirement †				Trend
	2024-25	2029-30	2034-35	2039-40	
Burnie 110 kV	348 MVA	385 MVA	399 MVA	535 MVA	More time spent below minimum.
George Town 220 kV	655 MVA	813 MVA	844 MVA	1,068 MVA	More time spent below minimum.
Risdon 110 kV	346 MVA	558 MVA	605 MVA	916 MVA	More time spent below minimum.
Waddamana 220 kV	359 MVA	652 MVA	680 MVA	977 MVA	More time spent below minimum.

† AEMO and TasNetworks use pre-contingency values to inform the operational arrangements for system strength requirements in Tasmania. These nodes have specific local requirements which must be met for the pre-contingent levels, namely requirements to do with maintaining Basslink requirements, switching requirements for local reactive plant, and some power quality requirements for metropolitan load centres.

Projected vs required level of fault current available at least 99% of the time

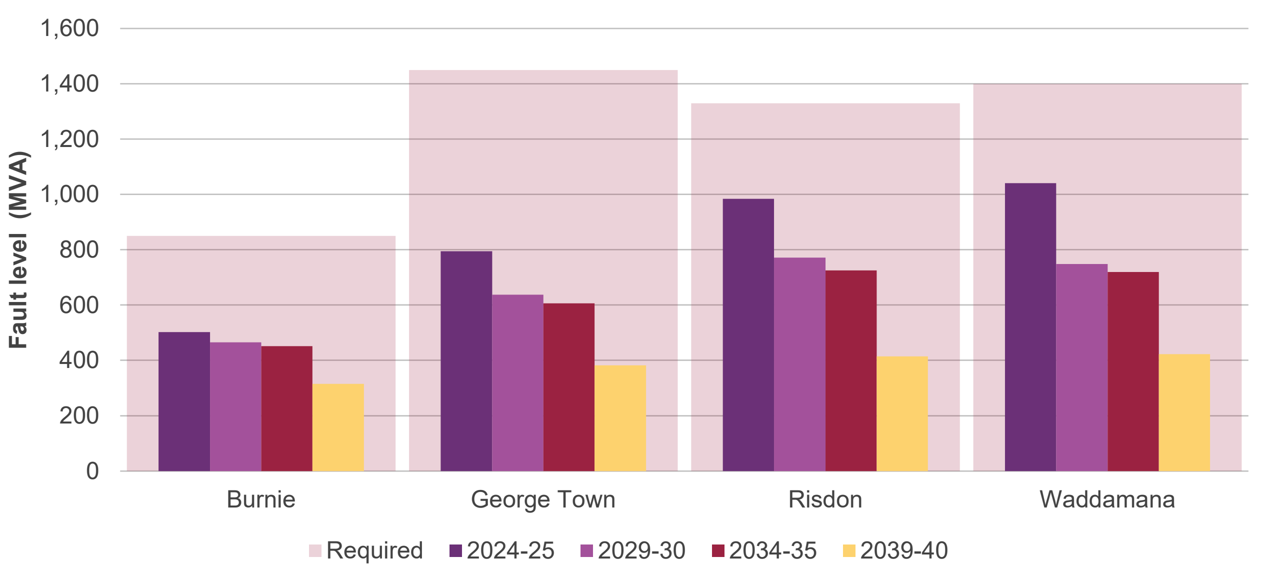
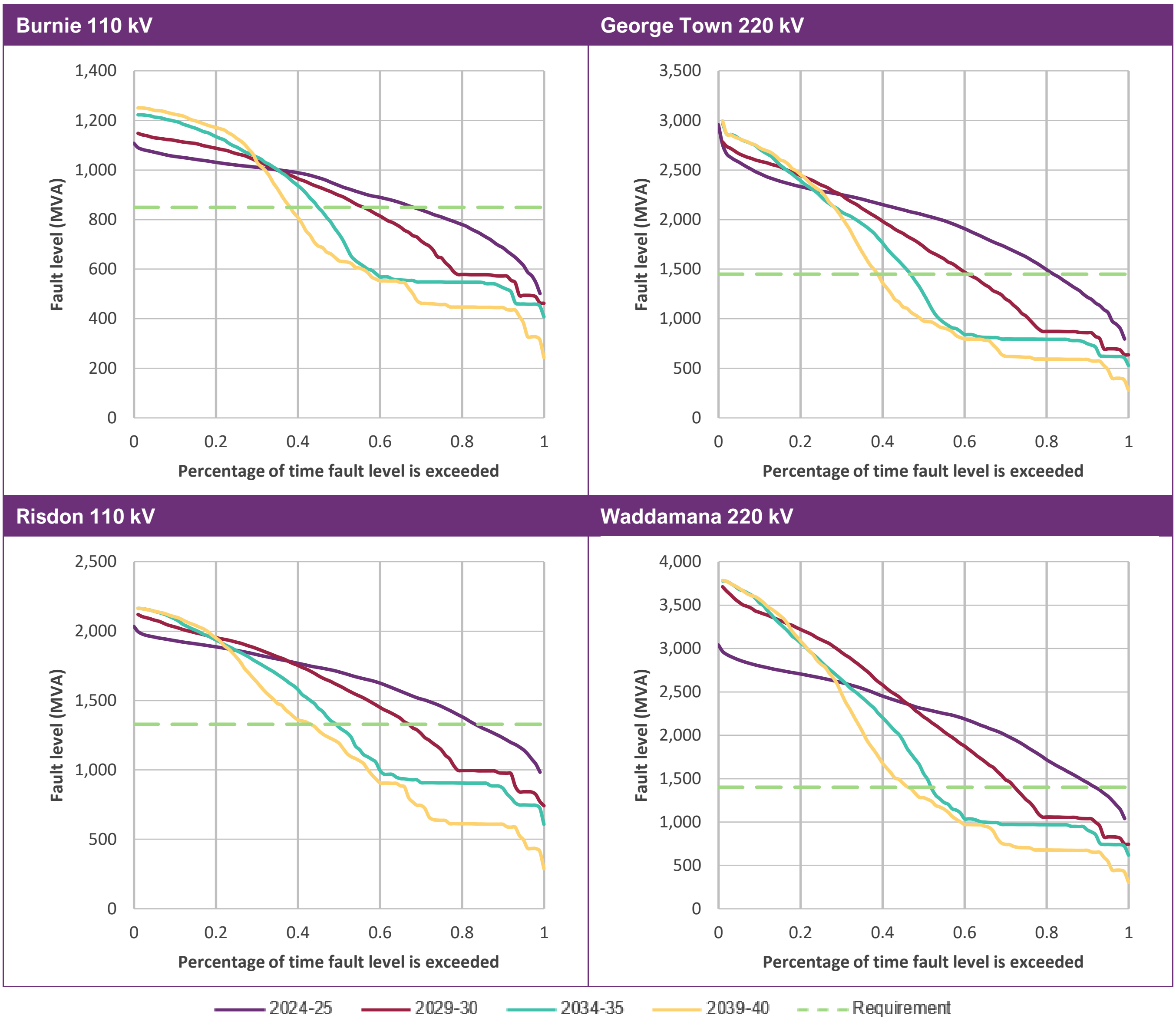


Figure 14 Percentage of time fault level is exceeded at each system strength node in Tasmania



System strength outlook – new IBR investment

Figure 15 IBR projections for Tasmania in 2024-25, 2029-30, 2034-35, and 2039-40 (MW)

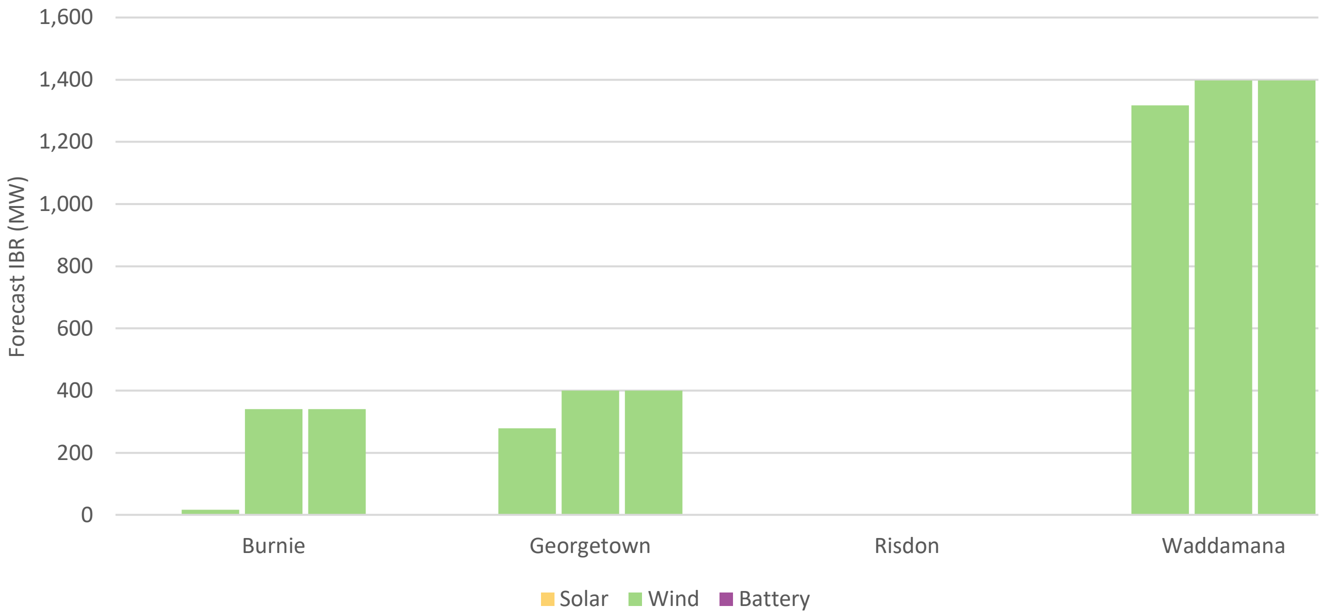


Table 7 IBR projections for Tasmania (MW)

Node	Technology	Existing	2024-25	2029-30	2034-35	2039-40
Burnie	Solar	0	0	0	0	0
	Wind	250	0	17	340	340
	Battery	0	0	0	0	0
Georgetown	Solar	0	0	0	0	0
	Wind	168	0	279	400	400
	Battery	0	0	0	0	0
Risdon	Solar	0	0	0	0	0
	Wind	0	0	0	0	0
	Battery	0	0	0	0	0
Waddamana	Solar	0	0	0	0	0
	Wind	144	0	1,318	1,398	1,398
	Battery	0	0	0	0	0

Inertia outlook

Key inertia results

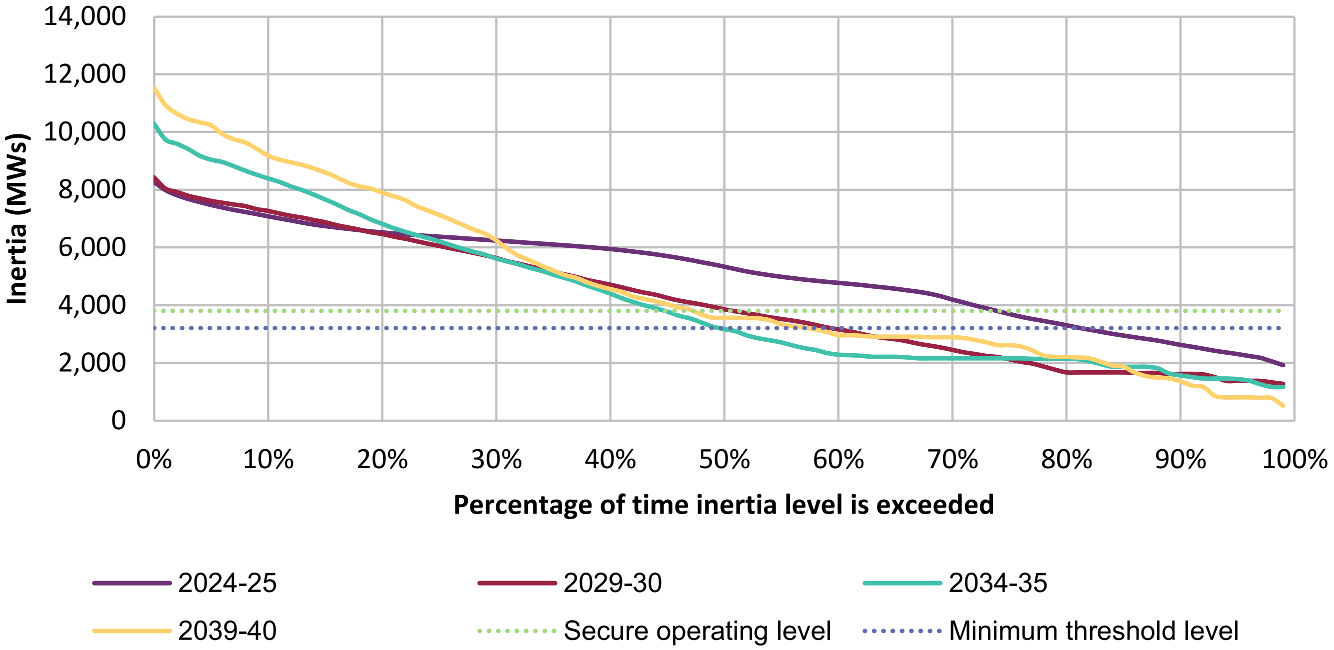
AEMO identified inertia deficits in all studied years. Inertia levels are predominantly consistent with the Draft 2024 ISP, although a larger deficit is projected for 2039-40 compared to the Draft 2024 ISP.

In the 2023 *Inertia Report*, AEMO declared an inertia shortfall of 1,880 MWs in 2024-25. The inertia deficits identified for years 2029-30, 2034-35, and 2039-40 will likely lead to declarations of inertia shortfalls in future Inertia Reports as these years move within the five-year Inertia Report assessment window.

Table 8 Inertia outlook for Tasmania

Inertia projections				
	2024-25	**2029-30**	**2034-35**	**2039-40**
Minimum threshold of inertia (MWs)	3,200	3,200	3,200	3,200
Secure operating level of inertia (MWs)	3,800	3,800	3,800	3,800
Inertia available 99% of the time (MWs)	1,926	1,270	1,167	511
Calculated inertia deficit (MWs)	1,874	2,530	2,633	3,289
Likelihood of islanding	Always	Always	Always	Always

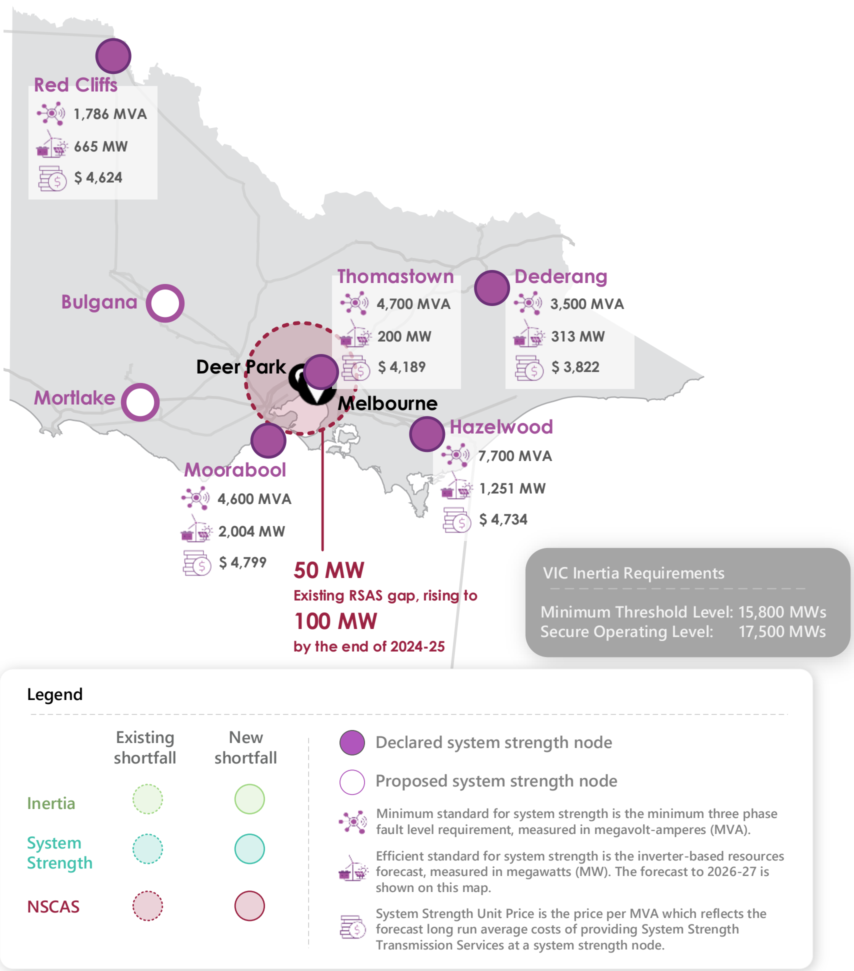
Figure 16 Projected levels of inertia available in Tasmania, *Step Change* scenario (MWs)



A1.4.6 Victoria

System strength outlook – synchronous fault levels

System strength requirements (pre/post contingent)



Key results

Projected closure of coal-fired generation and declining utilisation of others is expected to significantly reduce synchronous fault current at several nodes within Victoria.

Most of the projected need for fault current remediation occurs by the end of the decade.

Projected shortfalls against current minimum requirements

Node	Shortfall against minimum requirement				Trend
	2024-25	2029-30	2034-35	2039-40	
Dederang 220 kV	0 MVA	349 MVA	404 MVA	404 MVA	The synchronous fault current at these nodes is expected to fall sharply over the decade, but further reductions are not expected in the remaining planning horizon.
Hazelwood 500 kV	0 MVA	4,542 MVA	4,202 MVA	4,194 MVA	
Moorabool 220 kV	0 MVA	1,344 MVA	945 MVA	946 MVA	
Thomastown 220 kV	0 MVA	1,801 MVA	1,459 MVA	1,435 MVA	
Red Cliffs 220 kV	0 MVA	0 MVA	0 MVA	0 MVA	The synchronous fault level at Red Cliffs is expected to increase with commissioning completion of Project EnergyConnect Stage 2.

Projected vs required level of fault current available at least 99% of the time

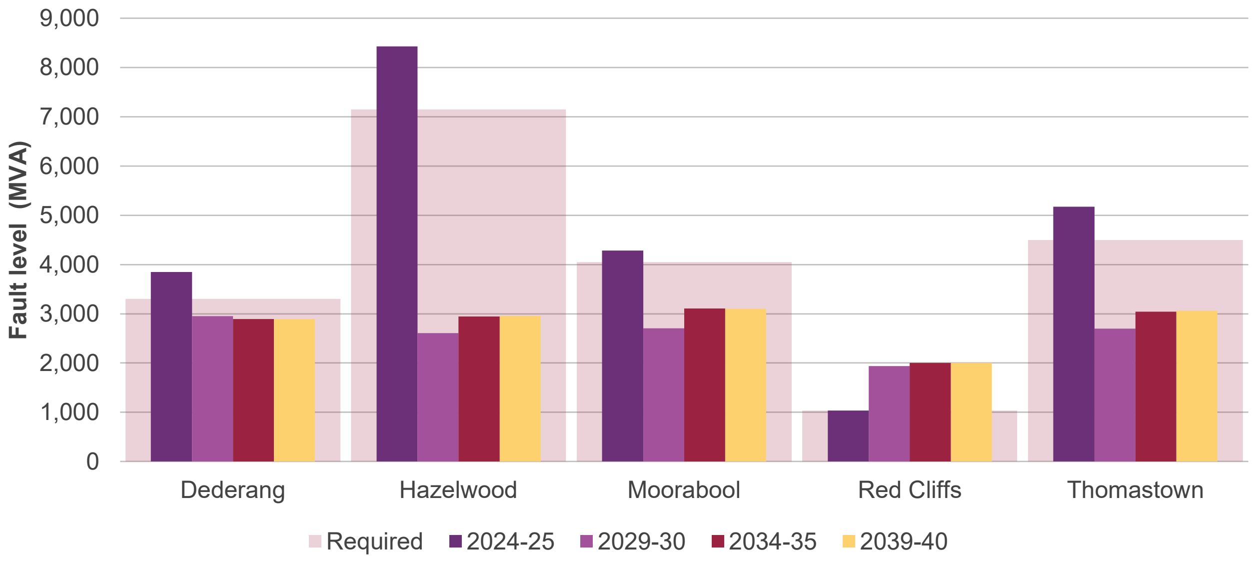
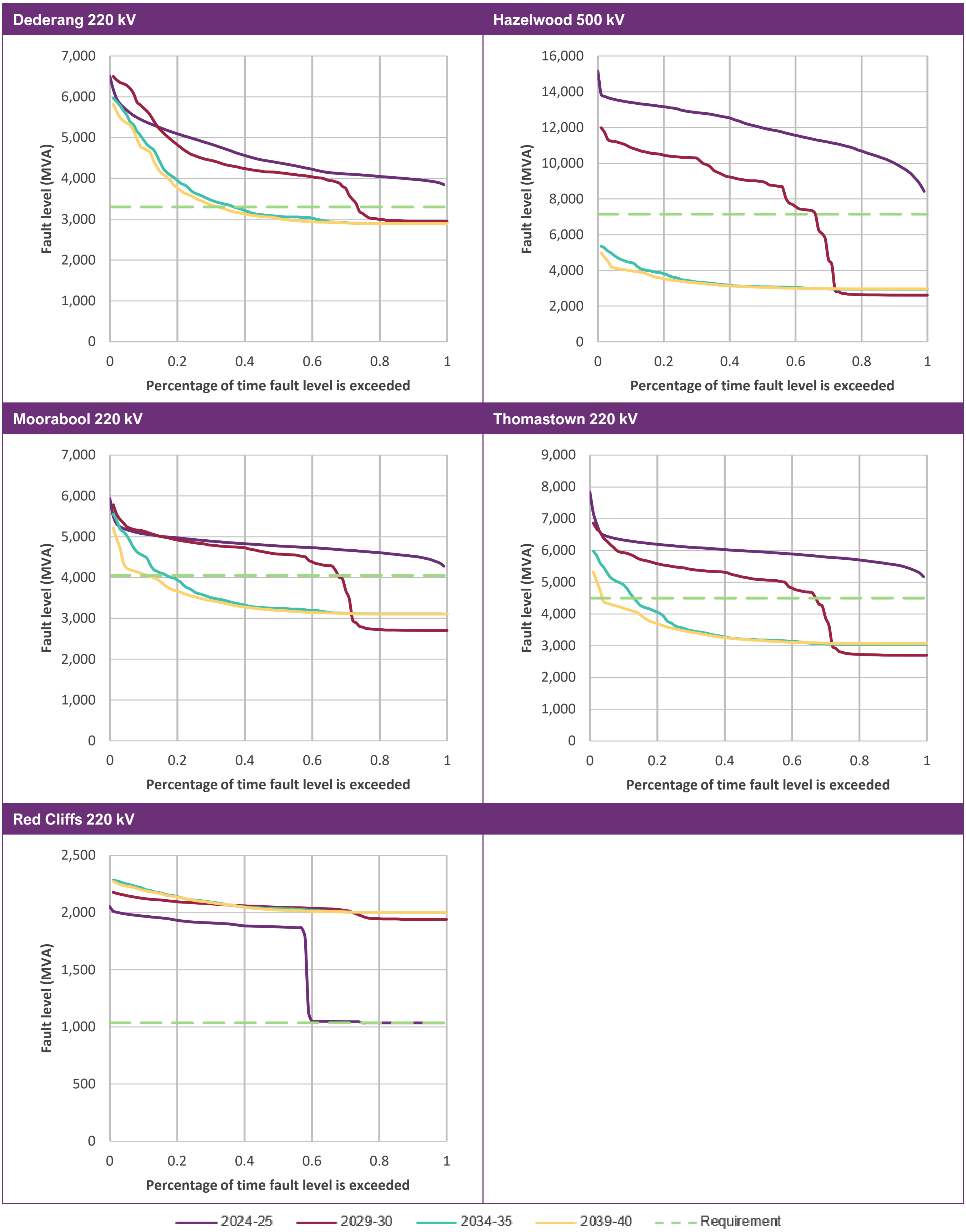


Figure 17 Percentage of time fault level is exceeded at each system strength node in Victoria



System strength outlook – new IBR investment

Figure 18 IBR projections for Victoria in 2024-25, 2029-30, 2034-35, and 2039-40 (MW)

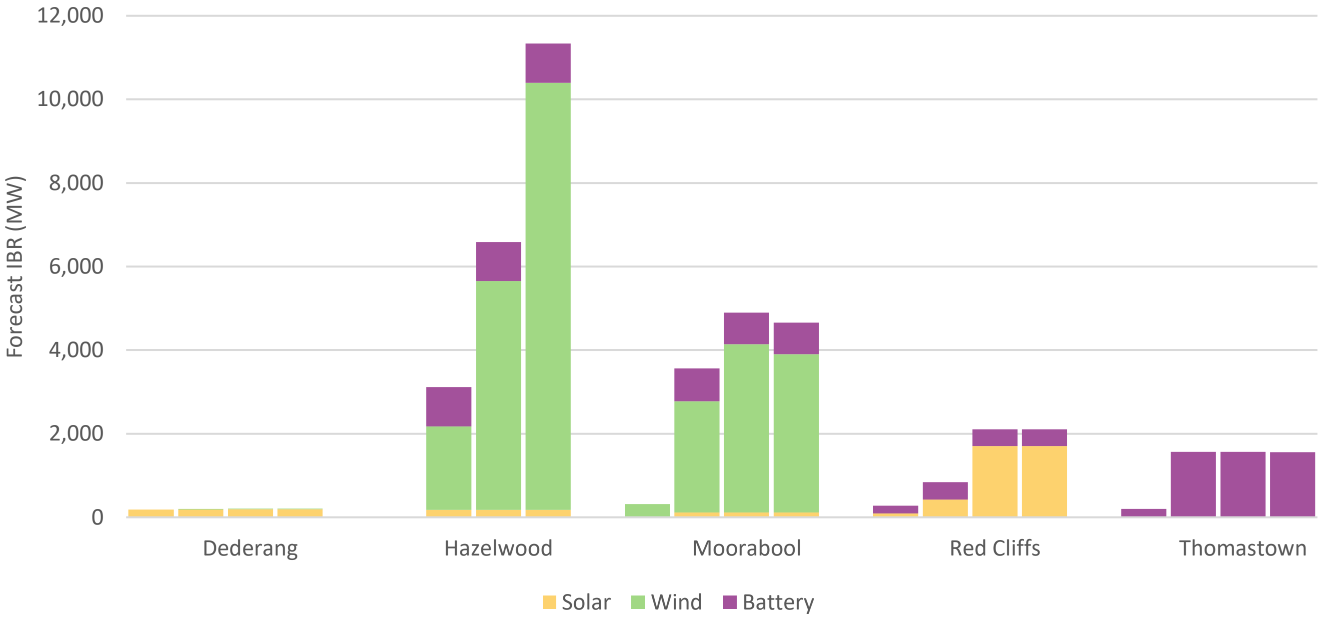


Table 9 IBR projections for Victoria (MW)

Node	Technology	Existing	2024-25	2029-30	2034-35	2039-40
Dederang	Solar	401	187	187	197	197
	Wind	0	0	14	14	14
	Battery	0	0	0	0	0
Hazelwood	Solar	0	0	178	178	178
	Wind	107	0	2,000	5,471	10,220
	Battery	200	0	940	940	940
Moorabool	Solar	0	0	119	119	119
	Wind	4,126	315	2,659	4,023	3,787
	Battery	350	0	782	752	752
Red Cliffs	Solar	682	95	423	1,708	1,708
	Wind	0	0	0	0	0
	Battery	25	185	420	395	395
Thomastown	Solar	0	0	0	0	0
	Wind	58	0	0	0	0
	Battery	5	200	1,565	1,565	1,560

Inertia outlook

Key inertia results

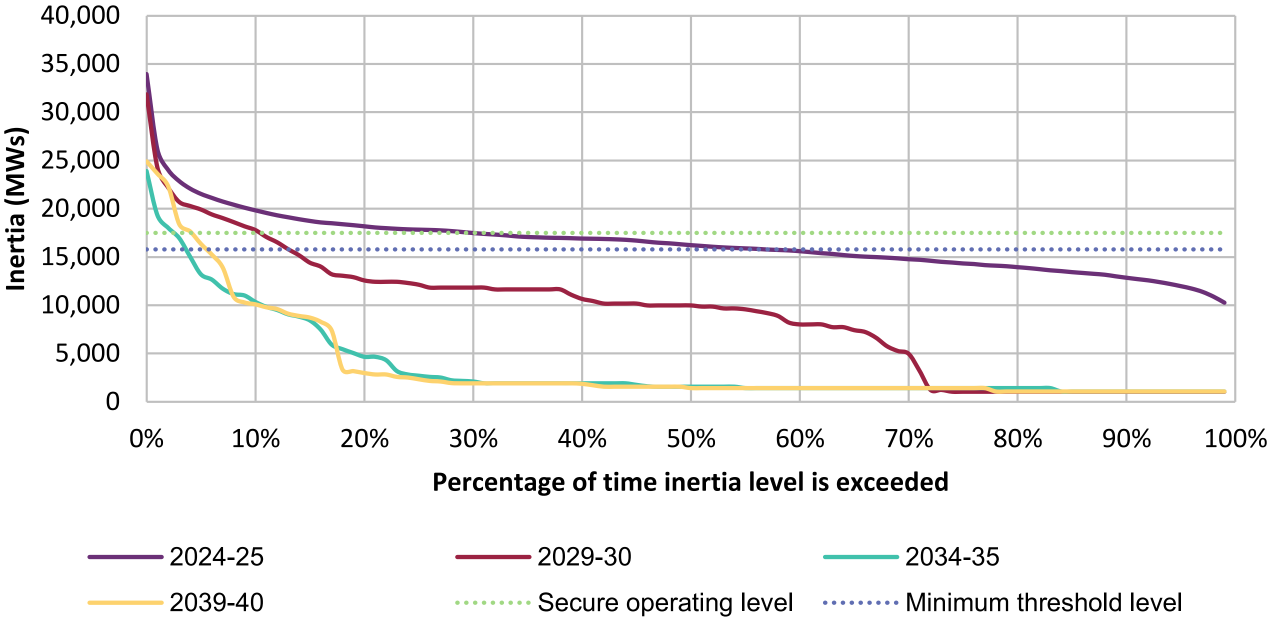
Inertia levels are predominantly consistent with the Draft 2024 ISP, but lower levels of inertia and increased inertia requirements lead to greater calculated inertia deficits than in the 2022 ISP.

AEMO identified inertia deficits in all studied years, however Victoria is not considered sufficiently likely to island due to its strong interconnections with neighbouring regions.

Table 10 Inertia outlook for Victoria

Inertia projections				
	2024-25	2029-30	2034-35	2039-40
Assumed level of 1-second FCAS (MW)	212	212	212	212
Minimum threshold of inertia (MWs)	15,800	15,800	15,800	15,800
Secure operating level of inertia (MWs)	17,500	17,500	17,500	17,500
Inertia available 99% of the time (MWs)	10,259	1,048	1,048	1,048
Calculated inertia deficit (MWs)	7,241	16,452	16,452	16,452
Likelihood of islanding	Unlikely	Unlikely	Unlikely	Unlikely

Figure 19 Projected levels of inertia available in Victoria, *Step Change* scenario MWs)



Glossary

This glossary has been prepared as a quick guide to help readers understand some of the terms used in the ISP. Words and phrases defined in the National Electricity Rules (NER) have the meaning given to them in the NER. This glossary is not a substitute for consulting the NER, the Australian Energy Regulator's (AER's) Cost Benefit Analysis Guidelines, or AEMO's *ISP Methodology*.

Term	Acronym	Explanation
Actionable ISP project	-	Actionable ISP projects optimise benefits for consumers if progressed before the next ISP. A transmission project (or non-network option) identified as part of the ODP and having a delivery date within an actionable window. For newly actionable ISP projects, the actionable window is two years, meaning it is within the window if the project is needed within two years of its earliest in-service date. The window is longer for projects that have previously been actionable. Project proponents are required to begin newly actionable ISP projects with the release of a final ISP, including commencing a RIT-T.
Actionable New South Wales project and actionable Queensland project	-	A transmission project (or non-network option) that optimises benefits for consumers if progressed before the next ISP, is identified as part of the ODP, and is supported by or committed to in New South Wales Government or Queensland Government policy and/or prospective or current legislation.
Anticipated project	-	A generation, storage or transmission project that is in the process of meeting at least three of the five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Anticipated projects are included in all ISP scenarios.
Candidate development path	CDP	A collection of development paths which share a set of potential actionable projects. Within the collection, potential future ISP projects are allowed to vary across scenarios between the development paths. Candidate development paths have been shortlisted for selection as the ODP and are evaluated in detail to determine the ODP, in accordance with the ISP Methodology.
Capacity	-	The maximum rating of a generating or storage unit (or set of generating units), or transmission line, typically expressed in megawatts (MW). For example, a solar farm may have a nominal capacity of 400 MW.
Committed project	-	A generation, storage or transmission project that has fully met all five commitment criteria (planning, construction, land, contracts, finance), in accordance with the AER's Cost Benefit Analysis Guidelines. Committed projects are included in all ISP scenarios.
Consumer energy resources	CER	Generation or storage assets owned by consumers and installed behind-the-meter. These can include rooftop solar, batteries and electric vehicles (EVs). CER may include demand flexibility.
Consumption	-	The electrical energy used over a period of time (for example a day or year). This quantity is typically expressed in megawatt hours (MWh) or its multiples. Various definitions for consumption apply, depending on where it is measured. For example, underlying consumption means consumption being supplied by both CER and the electricity grid.
Cost-benefit analysis	CBA	A comparison of the quantified costs and benefits of a particular project (or suite of projects) in monetary terms. For the ISP, a cost-benefit analysis is conducted in accordance with the AER's Cost Benefit Analysis Guidelines.
Counterfactual development path	-	The counterfactual development path represents a future without major transmission augmentation. AEMO compares candidate development paths against the counterfactual to calculate the economic benefits of transmission.

Term	Acronym	Explanation
Demand	-	The amount of electrical power consumed at a point in time. This quantity is typically expressed in megawatts (MW) or its multiples. Various definitions for demand, depending on where it is measured. For example, underlying demand means demand supplied by both CER and the electricity grid.
Demand-side participation	DSP	The capability of consumers to reduce their demand during periods of high wholesale electricity prices or when reliability issues emerge. This can occur through voluntarily reducing demand, or generating electricity.
Development path	DP	A set of projects (actionable projects, future projects and ISP development opportunities) in an ISP that together address power system needs.
Dispatchable capacity	-	The total amount of generation that can be turned on or off, without being dependent on the weather. Dispatchable capacity is required to provide firming during periods of low variable renewable energy output in the NEM.
Distributed solar/ distributed PV	-	Solar photovoltaic (PV) generation assets that are not centrally controlled by AEMO dispatch. Examples include residential and business rooftop PV as well as larger commercial or industrial "non-scheduled" PV systems.
Firming	-	Grid-connected assets that can provide dispatchable capacity when variable renewable energy generation is limited by weather, for example storage (pumped-hydro and batteries) and gas-powered generation.
Future ISP project	-	A transmission project (or non-network option) that addresses an identified need in the ISP, that is part of the ODP, and is forecast to be actionable in the future.
Identified need	-	The objective a TNSP seeks to achieve by investing in the network in accordance with the NER or an ISP. In the context of the ISP, the identified need is the reason an investment in the network is required, and may be met by either a network or a non-network option.
ISP development opportunity	-	A development identified in the ISP that does not relate to a transmission project (or non-network option) and may include generation, storage, demand-side participation, or other developments such as distribution network projects.
Net market benefits	-	The present value of total market benefits associated with a project (or a group of projects), less its total cost, calculated in accordance with the AER's Cost Benefit Analysis Guidelines.
Non-network option	-	A means by which an identified need can be fully or partly addressed, that is not a network option. A network option means a solution such as transmission lines or substations which are undertaken by a Network Service Provider using regulated expenditure.
Optimal development path	ODP	The development path identified in the ISP as optimal and robust to future states of the world. The ODP contains actionable projects, future ISP projects and ISP development opportunities, and optimises costs and benefits of various options across a range of future ISP scenarios.
Regulatory Investment Test for Transmission	RIT-T	The RIT-T is a cost benefit analysis test that TNSPs must apply to prescribed regulated investments in their network. The purpose of the RIT-T is to identify the credible network or non-network options to address the identified network need that maximise net market benefits to the NEM. RIT-Ts are required for some but not all transmission investments.
Reliable (power system)	-	The ability of the power system to supply adequate power to satisfy consumer demand, allowing for credible generation and transmission network contingencies.
Renewable energy	-	For the purposes of the ISP, the following technologies are referred to under the grouping of renewable energy: "solar, wind, biomass, hydro, and hydrogen turbines". Variable renewable energy is a subset of this group, explained below.
Renewable energy zone	REZ	An area identified in the ISP as high-quality resource areas where clusters of large-scale renewable energy projects can be developed using economies of scale.
Renewable drought	-	A prolonged period of very low levels of variable renewable output, typically associated with dark and still conditions that limit production from both solar and wind generators.

Term	Acronym	Explanation
Scenario	-	A possible future of how the NEM may develop to meet a set of conditions that influence consumer demand, economic activity, decarbonisation, and other parameters. For the 2024 ISP, AEMO has considered three scenarios: *Progressive Change*, *Step Change* and *Green Energy Exports*.
Secure (power system)	-	The system is secure if it is operating within defined technical limits and is able to be returned to within those limits after a major power system element is disconnected (such as a generator or a major transmission network element).
Sensitivity analysis	-	Analysis undertaken to determine how modelling outcomes change if an input assumption (or a collection of related input assumptions) is changed.
Spilled energy	-	Energy from variable renewable energy resources that could be generated but is unable to be delivered. Transmission curtailment results in spilled energy when generation is constrained due to operational limits, and economic spill occurs when generation reduces output due to market price.
Transmission network service provider	TNSP	A business responsible for owning, controlling or operating a transmission network.
Utility-scale or utility		For the purposes of the ISP, ‘utility-scale’ and ‘utility’ refers to technologies connected to the high-voltage power system rather than behind the meter at a business or residence.
Value of greenhouse gas emissions reduction	VER	The VER estimates the value (dollar per tonne) of avoided greenhouse gas emissions. The VER is calculated consistent with the method agreed to by Australia’s Energy Ministers in February 2024.
Virtual power plant	VPP	An aggregation of resources coordinated to deliver services for power system operations and electricity markets. For the ISP, VPPs enable coordinated control of CER, including batteries and electric vehicles.
Variable renewable energy	VRE	Renewable resources whose generation output can vary greatly in short time periods due to changing weather conditions, such as solar and wind.