AUSTRALIAN ENERGY MARKET OPERATOR

2025 Transition Plan for System Security

December 2025

Maintaining system security through the energy transition

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

AEMO is required to publish the Transition Plan for System Security, specific to clause 5.20.8 of the National Electricity Rules. This publication provides a plan to maintain power system security in the National Electricity Market through the energy transition to a low- or zero-emissions power system. It further outlines the work AEMO is undertaking to improve this understanding and to specify the range of services that may be required. This publication is based on information available to AEMO as of 1 December 2025 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	1/12/2025	First release
1.1	27/2/2026	Minor corrections

CEO preface

Dear colleagues and stakeholders,

I'm pleased to share the 2025 *Transition Plan for System Security*, the most comprehensive plan to meet system security requirements as well as consumer needs for the National Electricity Market (NEM).

Australia's energy system is changing rapidly. Coal-fired power stations are retiring and being replaced with a combination of renewable energy, storage and gas-powered generators. Australian consumers continue to invest in rooftop solar at a world leading pace and they are now adding home batteries and electric vehicles.

Throughout this transition, the NEM must be both reliable and secure. To be reliable, there must be enough generation to meet consumer needs at any point in time. To be secure, the power system must operate safely within its defined technical limits, withstand disturbances, and be able to restart in the event of a widespread outage.

For decades, system security services have been a by-product of coal-fired power generation. As these aging generators withdraw and retire, replacement services must be delivered on time to support higher levels of renewable energy produced by residential rooftops and commercial scale generators.

This report outlines key transition points in the power system, and the required investments and collaborative actions for the energy sector to navigate the next decade of the energy transition. It builds on AEMO's previous publications and the ongoing work of industry and governments to support reliable and secure power supply for consumers.

System security is a shared responsibility, and this *Transition Plan for System Security* has been developed in collaboration with industry, governments and consumer representatives.

I would like to thank everyone who has been involved in the preparation of this report.

Daniel Westerman

Chief Executive Officer

Executive summary

The Australian Energy Market Operator (AEMO) operates the power system to maintain a secure and reliable supply of electricity for homes and businesses across the National Electricity Market (NEM). The system continues to undergo a period of renewal as coal-fired generators age and approach retirement, as renewable generation and consumer energy resources (CER) continue to grow, and as technology evolves.

Renewable energy, connected by transmission and distribution, firmed with storage and backed up by gas-powered generation (GPG), presents the least-cost way to meet both consumer needs and government energy and emission policies through to 2050. AEMO's *Transition Plan for System Security* details the plan for system *security* needs in the next 10 years to support the energy transition.

System security solutions are evolving

A secure power system is one operated safely within defined technical limits, with the ability to withstand credible disturbances, return to secure operation, and restart following a widespread outage.

While reliability requires sufficient generation and network capacity to meet customer demand, the requirements for system security are more technical, and include system strength[1], frequency and inertia, voltage control, transient and oscillatory stability, operability, and system restoration.

The fundamentals of power system security are enduring, but how they are being provided is changing. The next 10 years are important as renewable and inverter-based generation increases and demand and market participation evolve to replace coal generators that are increasingly withdrawing from the power system – either commercially for hours, days or months, operationally for planned or unplanned maintenance, or completely due to retirement. Today, renewables supply more than 40% of total annual electricity demand in the NEM, with 30-minute peaks approaching 80%. In South Australia, renewables regularly peak at over 100% of demand.

There are shared responsibilities for system security

The National Electricity Rules (NER) outline responsibilities for AEMO, network service providers (NSPs) and market participants to collectively ensure system security in the NEM through operation of the energy market and planning frameworks.

If system security gaps have not been met through planning and market operation, there is a limited hierarchy of operational controls and interventions to maintain system security, proportional to the risk in real time. Market interventions can result in significant costs and risks of interruptions to power supply, so it is critical the energy sector continues to collaboratively plan and navigate this path with consumers' interests at the centre.

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[1] System strength refers to the ability of a power system to maintain and control the voltage waveform at any location, both during normal operation and following a disturbance.

AEMO's 2025 Transition Plan for System Security

The *Transition Plan for System Security* consolidates four previous AEMO reports into a single plan that identifies emerging security gaps, required investments, and collaborative actions for AEMO, governments, NSPs and market participants. It builds on AEMO's annual reporting of system strength, inertia and non-market ancillary service (NMAS) requirements, and provides a guide for the sector through the next phase of the energy transition, focusing on key transition points and actions required.

System security requirements are well understood, and frameworks are evolving to maintain them through the transition

AEMO's Engineering Roadmap[2] identified the technical requirements for the NEM to operate securely with periods of up to 100% renewable generation. The core technical requirements remain the same, even as technologies change, providing both opportunities and challenges in ensuring system security through the energy transition.

To manage the change, AEMO has developed a transition planning framework to navigate key "transition points" – events and milestones that require material changes in the operational approach to managing power system security, and in particular progressive coal decommitments and closures.

New Transitional Services introduced under the 2024 Improving Security Frameworks (ISF) rule change[3] have commenced and will support operability and help trial new technologies such as grid-forming (GFM) inverters to deliver critical security services. AEMO has recently published Statements of Security Need for several Transitional Services, with more in development[4].

Additionally, in November 2025, AEMO requested the Australian Energy Market Commission (AEMC) amend the NER's planning and procurement frameworks for system strength and inertia, building on recent updates to support the efficient and timely deployment of resources required to meet system security needs over the energy transition. The rule change request focuses on options to address issues including the timing mismatch between transition points where security resources exit and the longer lead times within which approval, procurement and commissioning activities can respond[5].

Investment in new sources of system security is needed

Ten coal-fired power stations have closed since 2012 and half of the remaining fleet is projected to retire in the coming 10 years, as well as several large gas generators. New investments and reforms are needed to maintain system security in advance of these exits occurring, with opportunities to co-optimise both reliability and security to help keep costs of the transition as low as possible. For example:

- Gas turbines (GTs) fitted with clutches (at design or retrofit) can act as synchronous condensers, providing security services even when not generating power. If fitted with self-start capabilities, these units can also support system restart.

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

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

[4] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services.

[5] See https://www.aemc.gov.au/rule-changes/security-framework-enhancements.

- Synchronous condensers fitted with a flywheel can provide both system strength and inertia.
- Grid-forming battery energy storage systems (BESS) are progressing rapidly to be able to deliver a wide range of system security services in the NEM such as frequency control, voltage stability and some aspects of system strength.

AEMO's 2025 system strength and inertia assessments have confirmed the importance of delivering system strength and inertia solutions in tandem.

Many assets capable of providing system security services are progressing but have long lead times (five or more years) for approvals, procurement and installation. Readiness is required for when coal generators commercially implement more flexible operating profiles such as going offline during the middle of the day or seasonally, which may occur many years before retirement.

> ***Timely investments are needed to decouple reliance on coal generators for system security – enabling the next phase of the energy transition.***

CER are becoming increasingly central to system operation, and AEMO is taking steps to continue to encourage CER growth and ensure households and businesses can continue to have a meaningful impact on Australia's energy transition. The last decade has seen significant effort to support the transition to greater amounts of large-scale renewables, including improved performance standards and new operational approaches to maintain system security and reliability. A similar concerted effort is required to ensure CER are effectively integrated in a way that supports the secure and reliable delivery of electricity to all consumers now and into the future. Reforms under the National CER Roadmap are important and progressing, including those that support visibility, predictability, standards, and participation in an increasingly two-sided system.

When high output from rooftop solar combines with low underlying demand, operational demand on the transmission system can be significantly reduced, creating minimum system load (MSL) conditions. MSL management remains an ongoing priority across all NEM regions to ensure supply-demand balance across all elements of the power system. In the near term, if replacement sources of system security services are delivered on time, the system can continue to support higher contributions of rooftop solar, and emergency backstop capability, which pauses or restricts rooftop solar exports to the grid, will remain rare. If delayed, costs and interventions (including the possibility of using emergency backstop mechanisms) are likely to rise.

New approaches for system restart are required before traditional providers exit the market. In the short to medium term, strategic investment will be needed to ensure restart during the transition. Over this timeframe AEMO expects an evolution of restart processes, with the restart process to remain primarily focused on restarting existing large grid- connected plant and priority load centres. In the longer term, the restart process may need to fundamentally change, to be more decentralised in nature, and take into account emerging technologies. AEMO is exploring restoration support services to address stable load unavailability, and two new Type 2 Transitional Services trials to demonstrate black start capability using inverter-based resources (IBR) and to enable system restart in a high distributed photovoltaic (PV) environment.

Shortfalls in security investment mean action is needed for imminent transition points

Industry and governments are already acting to resolve known risks, with specific remedial action needed to navigate fast-approaching transition points:

- System strength requirements to enable the planned retirement of Eraring Power Station have been identified by AEMO each year since 2021, and Transgrid is progressing the procurement of new synchronous condensers. The decommitment of Eraring before these synchronous condensers are operational would result in the activation of Transgrid system security contracts (where available). 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.
- There remains a need for increased emergency distributed PV backstop capacity, particularly in Queensland, to maintain system security and avoid widespread customer impacts in rare, but plausible, operating conditions (for example, a combination of significant load outages, network outages, and/or islanded regions). Backstop capacity is needed in addition to ongoing efforts to leverage storage and increase daytime demand.
- Delivery of synchronous condensers and planned metro grid reinforcement projects will help manage system strength and improve transfer capacity into metropolitan Melbourne following the exit of Yallourn Power Station. AEMO expects to rely on system security contracts and directions to existing synchronous plant to maintain system strength, until delivery of new synchronous condensers, with risks of there being limited available assets to direct. If gas generators needed to be directed online to maintain system strength, adequate fuel supplies would be essential.
- The planned exit of Gladstone Power Station in March 2029 requires timely delivery of the Gladstone Priority Transmission Investment project, in parallel with system strength investments.

Transmission network service providers (TNSPs) are responsible for procuring system strength services and governments and AEMO are supporting them where necessary to prioritise delivery of relevant solutions. AEMO also continues to support proactive reforms to security frameworks through the Energy and Climate Change Ministerial Council, NEM Wholesale Market Settings Review, and through the AEMC's rule change process[6].

Summary of regional transition plans and detailed system security assessments

Table 1 summarises key transition points in each NEM region, in both operational (up to two years) and investment (two to 10 years) timeframes, highlighting levels of industry readiness and associated action for each. Regional transition plans are provided in full in Part B of this report.

Detailed assessments of system strength, inertia, and ancillary service shortfalls which create requirements for TNSPs are summarised in **Table 2** and presented in detail in Appendix A2.

Based on the non-market ancillary service (NMAS) 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.

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[6] For example, https://www.aemc.gov.au/rule-changes/security-framework-enhancements.

Table 1 Summary of NEM transition points

Horizon 1: 0-2 years

Operational timeframes with existing tools

Horizon 2: 2-10 years

Investment timeframes with planning frameworks

2025

🟢 SA — **SA 1 min sync generator**
Successful reduction of minimum sync. generators to one, in Sept 2025

🟢 SA — **SA minimum system load (MSL)**
Adequate options were available via directions to manage projected MSL periods.

🟢 VIC — **Vic MSL**
Adequate options were available to manage forecast minimum demand periods via contracts and directions, though some scenarios could have required last resort mechanisms.

2026

🔴 QLD — **Qld MSL**
Action required to ensure additional mechanisms are available to manage system security under certain (low probability) onerous system conditions.

🟡 NSW, SA, VIC — **NSW, SA, Vic MSL**
Adequate options forecast to be available to manage minimum demand periods with the use of directions and transitional services where available. Last resort options may still need to called upon in certain (low probability) onerous system conditions.

2027

🔴 NSW — **Eraring exit**
Assets flagged for system strength requirements are not scheduled to be operational before announced retirement date.

🟡 SA — **SA 0 min sync generators**
Following Project EnergyConnect Stage 2 and evidence of secure operation, reduction to 0 min. sync. generators in SA is possible.

🟢 QLD — **Qld first coal station potentially offline**
System strength and inertia shortfalls from market dispatch are possible but sufficient assets remain available for contract or direction if required.

2028

🟡 VIC — **Yallourn exit**
Projects in pipeline to manage system strength and thermal limits. Procurement risks for system strength solutions means potential reliance on contracts or directions with limited available assets that could be impacted by gas adequacy.

⚪ SA — **Torrens Island B exit**
Monitored potential transition point.

2029

🟢 QLD — **Gladstone exit**
Powerlink actively progressing projects to resolve anticipated system security and reliability issues following scheduled retirement in 2029.

🟡 NSW — **NSW second coal station potentially offline**
2028-29
System strength and inertia issues identified for Eraring retirement will be exacerbated. Little lead time for additional projects to be delivered.

2030-35

🟡 NSW — **NSW third coal station potentially offline**
2031-32
Large pipeline of projects with sufficient lead times ahead of target dates to ensure on-time and in-full delivery.

🟡 VIC — **Vic second coal station potentially offline**
2031-32
Additional solutions are required to ensure security given significantly higher reliance on remaining coal station

🟡 VIC — **Vic third coal station potentially offline**
2033-34
Security is contingent on planned assets being delivered ahead of coal decommitment.

🟡 NEM — **Continuing MSL and additional transition points**
MSL risks continue beyond 2027, with additional Horizon 2 transition points considered in further detail in Part B of the report.

Transition points are events that require material changes in the operational approach to managing system security. These utilise 2024 ISP Step Change projections, noting coal exit order is influenced by commercial drivers and asset condition. Additional points will be considered as required in future plans.

Industry readiness for transition point

🟢	Complete/ on track
🟡	Moderate readiness
🔴	Unresolved issues

Table 2 Summary of network requirements for each NEM region, to be addressed by TNSPs

Region (TNSP)	TNSP requirements
New South Wales (Transgrid) 	**System strength deficits across New South Wales have again been confirmed from 2027-28 with the currently announced Eraring Power Station retirement date.** 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. **Inertia deficits are also forecast from 2027-28**, 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. No gaps related to thermal loading or voltage control have been identified 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.
Queensland (Powerlink) 	There are **emerging system strength needs in Queensland from 2027-28, with solutions underway.** These needs are expected to be fully addressed by Powerlink's planned system strength solutions. Two **emerging inertia needs have been identified, with remedial measures underway.** 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**.** The successful delivery of the Gladstone Project transmission augmentation is essential 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.
South Australia (ElectraNet) 	**No system strength deficits have been identified.** **No inertia deficits have been identified.** The previously declared voltage control gap is actively being addressed. 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.
Tasmania (TasNetworks) 	AEMO has confirmed **projected system strength deficits across Tasmania**. TasNetworks is seeking to contract with existing assets to manage these requirements. I**nertia deficits have also been identified.** Contracts are being explored alongside system strength remediation. No gaps have been identified in relation to thermal loading or voltage control at this time.
Victoria (VicGrid) 	E**merging system strength needs are anticipated from 2028-29, primarily associated with the planned closure of Yallourn Power Station.** 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. An **inertia deficit has also been confirmed from 2027-28.** 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. AEMO confirmed the existing voltage control and thermal loading risks at Deer Park. 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.

Looking ahead

The *Transition Plan for System Security* builds on AEMO's annual analysis and reporting of system security needs to provide a consolidated blueprint for maintaining system security through Australia's energy transition. This plan is updated annually and will continue to dynamically evolve as capability, technology and understanding progresses. AEMO thanks industry partners and governments who have provided input and supported this work, and who continue to collaborate to enable Australia's energy transition.

In 2026, the *Transition Plan for System Security* will incorporate reporting of AEMO's Engineering Roadmap program and will include greater detail on future system restart requirements, grid-forming inverter capability, and integration of CER. Additionally, AEMO continues to work closely with our international peers, facilitating a shared approach to tackling obstacles and enabling rapid knowledge sharing and deployment of best practices and innovations[7].

Maintaining a secure and reliable energy system through the transition requires coordinated action across the energy sector, and AEMO will continue to work collaboratively to signal and support the investments, reforms, and innovations needed.

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[7] See https://www.aemo.com.au/initiatives/major-programs/international-system-operator-collaboration.

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Part A. Transition planning

Part A. Transition planning

The *Transition Plan for System Security* (TPSS) provides AEMO's plan to maintain system security over the coming decade**.** From this year onwards, the *Transition Plan for System Security* incorporates the previously separate system strength, inertia and network support and control ancillary services (NSCAS) reports[8], as shown in **Figure 1**. This change follows stakeholder feedback that a combined approach will aid clarity of understanding and cohesion of action for all stakeholders[9]. From 2026 onwards it will also include AEMO's Engineering Roadmap[10] reporting.

The report has three parts. Part A outlines the fundamental technical criteria – and critical importance – of system security, discusses how these fundamentals are enduring but the transition affects how they are fulfilled, and summarises how AEMO is planning to maintain security through the transition. Part B presents detailed transition plans for each NEM region, assessing industry readiness for transition points. Part C describes AEMO's evolving technical understanding of what is needed to maintain security in a low- or zero-emissions power system, including the latest developments on technologies and system services. This year's *Transition Plan for System Security* has three appendices, shown in **Table 3**.

Figure 1 Structure of combined security reporting in the *Transition Plan for System Security*

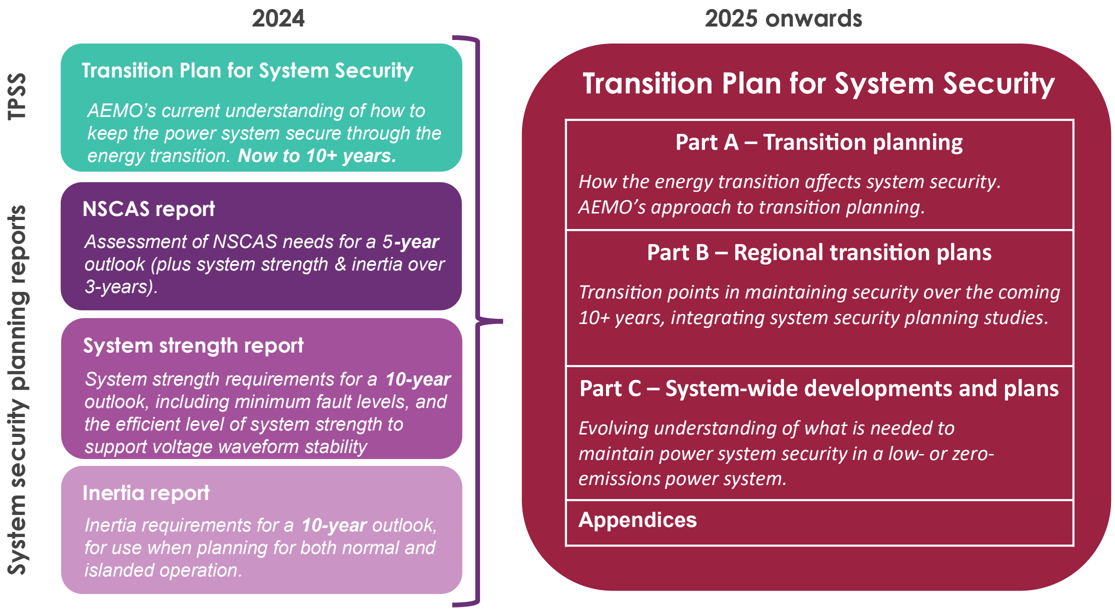

Table 3 *Transition Plan for System Security* appendices

Appendix	Description
Appendix A1	Reproduces the April 2025 letter from the Reliability Panel providing feedback on the 2024 *Transition Plan for System Security*.
Appendix A2	Contains NSCAS, system strength and inertia planning requirements for TNSPs.
Appendix A3	Contains minimum demand forecasts, current emergency backstop capacity, and forecast incidence of MSL events.

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

[9] See Section 2.5 for a summary of stakeholder feedback and Appendix A1 for the letter providing feedback from the Reliability Panel.

[10] See https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap.

1 How the transition affects system security

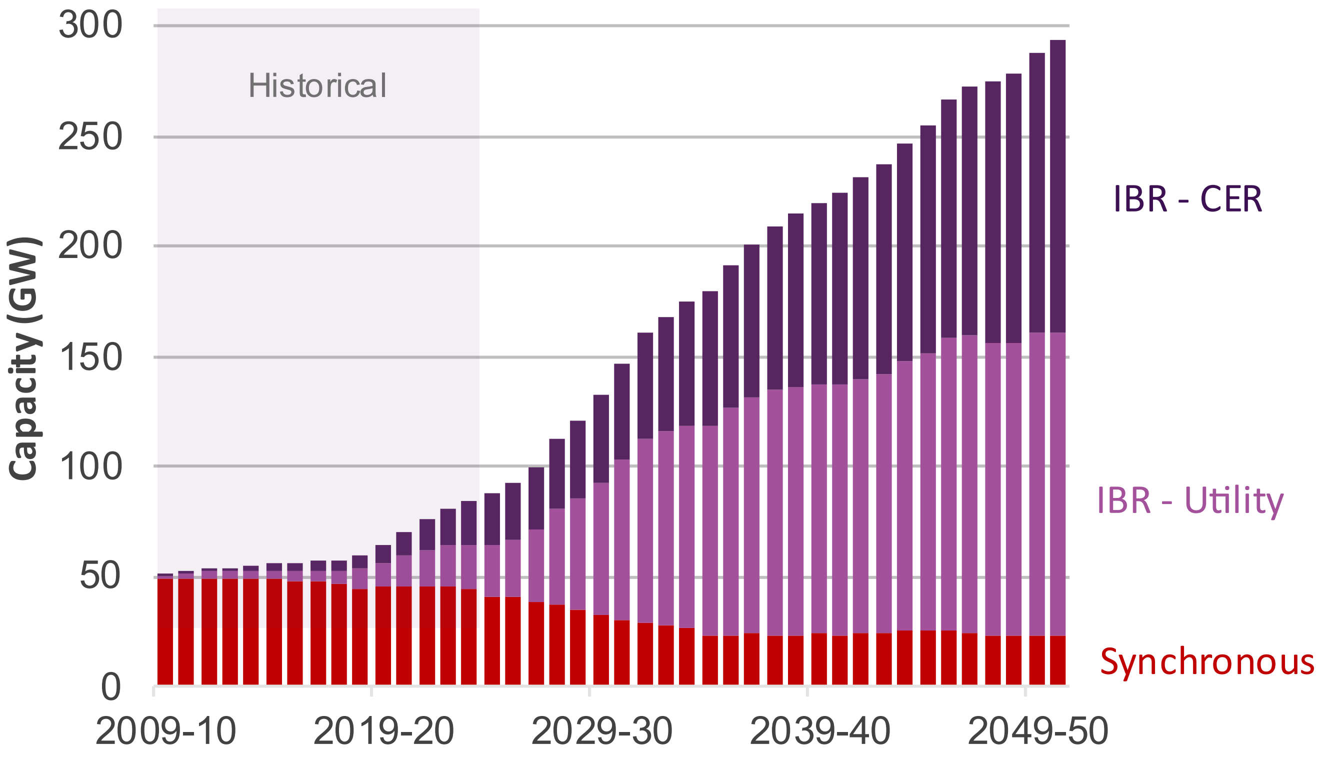
The NEM is in a period of renewal and transition, with significant change in the generation mix. Irrespective, the technical requirements, and critical importance, of system security are enduring. The ways in which security is maintained must evolve to ensure security does not become more operationally challenging.

1.1 The technology mix is changing

The NEM is in a period of renewal. Ten coal-fired power stations have closed since 2012 and retirements have been announced for all but one of the remaining fleet, with about half of the fleet planning to retire in the coming 10 years and the rest by 2048. To meet government policy objectives, AEMO's 2024 *Integrated System Plan* (ISP)[11] forecast that the remaining coal fleet may close faster than those announcements.

These synchronous generators are being replaced by a pipeline predominantly made up of inverter-based resources (IBR), such as wind turbines, batteries, and solar, including a large amount of distributed solar and batteries. AEMO expects these trends to continue in coming decades: for example, see **Figure 2** adapted from AEMO's 2024 ISP *Step Change* scenario[12].

Figure 2 Historical and forecast capacity of synchronous generation and IBR in the NEM, historical and in the ISP *Step Change* scenario, 2009-10 to 2049-50 (gigawatts [GW])



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[11] See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

[12] See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

1.1.1 Power system reliability and security

Definitions

Reliability

A *reliable* power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence[13]. The purpose of maintaining a *reliable* operating state is to ensure no customer supply is lost following a *credible contingency* event, such as the trip of a generator or line. The *reliability standard*[14] requires at least 99.998% of forecast customer demand to be met each year.

To be *reliable*, the power system must be in a secure operating state.

Security

A *secure* power system is one that is operated safely within defined technical limits, with ability to withstand credible disturbances, return to secure operation, and restart following a widespread outage. The purpose of maintaining a *secure* operating state is to prevent cascading failures following a *credible contingency* event.

Security depends on a broad set of technical requirements, including system strength, frequency and inertia, voltage control, transient and oscillatory stability, operability, and system restoration.

Managing both power system reliability and security during the energy transition, at least cost, is a priority.

The changing technology mix and shift to a more decentralised power system require evolution in the design and requirements across assets and actors, including changes to the way both power system *reliability* and *security* are maintained.

The approaches for managing security have been engineered to use the physical properties and control of the spinning masses in synchronous machines and have presumed a one-way flow of power from large generators to load centres. Adapting to these changes requires an evolution in the design and operation of IBR to comply with evolving grid codes and performance requirements, and the development of new approaches to system security that better align with the natural characteristics of IBR. These are being progressed as part of the AEMO's Engineering Roadmap[15].

1.1.2 International context and collaboration

Australia is not alone in navigating an energy transition. Since 2024, AEMO is one of six founding members of the International System Operator Network (ISON)[16] that facilitates a shared approach to tackling obstacles and enables rapid knowledge-sharing and deployment of best practices and innovations.

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[13] See https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability.

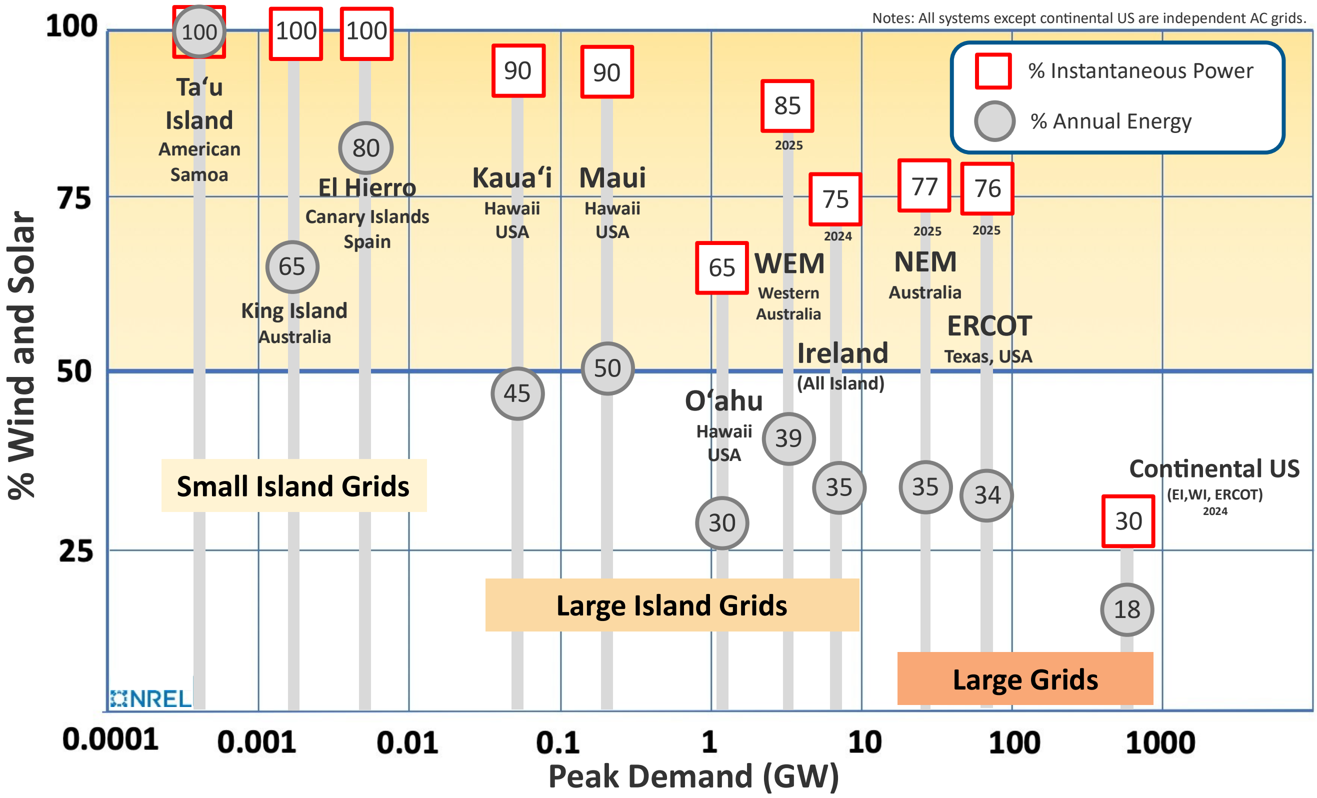
[14] The reliability standard is set in the NER and is reviewed by the independent Reliability Panel. It was last reviewed in 2018; see https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018.

[15] See page 25 of https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.

[16] See https://www.aemo.com.au/initiatives/major-programs/international-system-operator-collaboration.

While many nations and regions are undergoing transitions, **Figure 3** highlights how the NEM is at the forefront of large power systems in terms of instantaneous and average contributions from IBR (wind and solar), and the Wholesale Electricity Market (WEM) in Western Australia is at the forefront for large island grids[17].

Figure 3 Record contributions of wind and solar to total supply in grids globally



1.2 The technical requirements of power system security are enduring, but the way it is maintained is changing

While the energy transition is a period of profound change, the requirements that define a *secure* operating state will remain unchanged, as will the criticality of operating the power system in a *secure state*.

System security protects people's safety, protects equipment from damage, and protects the system from widespread blackouts. This section provides a conceptual background on power system security as a foundation to the remainder of the report.

1.2.1 Security is a property of the system not the parts

There is a common understanding of the word "security" when applied to daily life. For a house, security can be supported by connected communities, positive neighbourhoods, strong buildings and robust locks. For a bank account, security can be built through unguessable passwords, safe investments, encryption, and fraud-detection. For both, and depending on the

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[17] Prepared for this report by Benjamin Kroposki of the National Renewable Energy Laboratory.

risk environment, security can be supported by monitoring, insurance, and rapid response frameworks. With appropriate layers of protection, secure systems can be safe, resilient, impenetrable to credible attacks, and ultimately *dependable.*

While power systems are among the most complex machines ever built – comprising millions of electromechanical objects interacting near-instantaneously across great distances – similar principles of security apply. For the NEM, Chapter 4 of the NER[18] outlines in detail the framework for achieving power system security. This includes rules to keep electrical equipment within bounds of safe operation, frameworks to support the system remaining safe and secure in the event of credible risks, and emergency schemes to help prevent cascading failures. In the unlikely event of a region losing power or a system-black event, the NER prescribes the framework for system restart.

Just as the security of a house is not achieved through any individual lock installed for perpetuity without maintenance, or a bank account on any one password at a single point in time, achieving security for a power system requires careful coordination of multiple layers of operational controls, alongside continual assessments of the environments of risk within which it operates, with appropriate updates when required.

1.2.2 Managing system security involves assessing risks

The interactions of all the millions of components in the power system – across generation, network and load assets – in near real time create a complex system whose security in response to uncertain future disturbances is a matter of engineering judgement.

By NER definition, the *power system* is in a *secure operating state*[19] if, in AEMO's reasonable opinion, the system is in a *satisfactory operating state*[20] and will return to a *satisfactory operating state* following the occurrence of any *credible contingency event* or *protected event*. A *satisfactory operating state* is one in which frequency, voltage, current flows, and all connected plant are operating within their safe limits[21]. AEMO is obliged to take all reasonable actions to return the *power system* to a *secure operating state* within 30 minutes. **Figure 4** shows the relationship between secure and satisfactory states.

Understanding the central role of risk assessments in security – considering the likelihood and severity of events and their consequences – is pivotal to determining prudent actions to take in proportion to the probabilistic risks posed.

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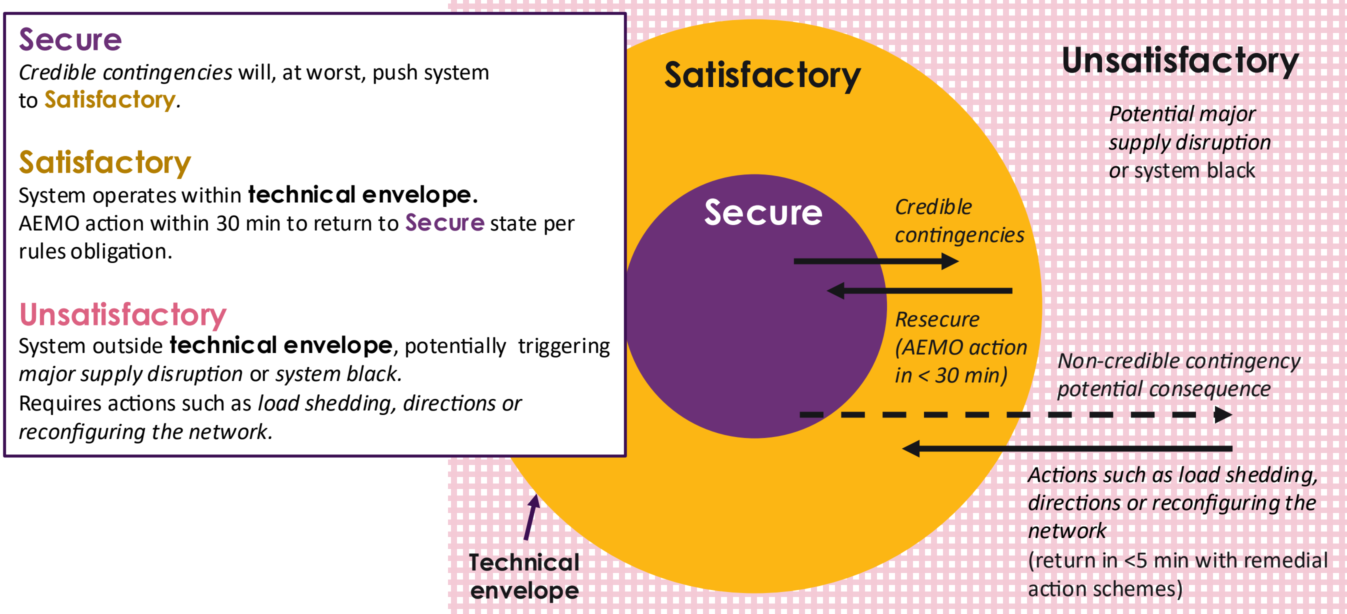
[18] See https://energy-rules.aemc.gov.au/ner/714.

[19] At https://energy-rules.aemc.gov.au/ner/714/690845#4.2.4.

[20] At https://energy-rules.aemc.gov.au/ner/714/690841#4.2.2.

[21] At https://aemo.com.au/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper.

Figure 4 Relationship between secure, satisfactory and unsatisfactory operating conditions



Secure
Credible contingencies will, at worst, push system to **Satisfactory**.

Satisfactory
System operates within **technical envelope.**
AEMO action within 30 min to return to **Secure** state per rules obligation.

Unsatisfactory
System outside **technical envelope**, potentially triggering *major supply disruption* or *system black.*
Requires actions such as *load shedding, directions or reconfiguring the network.*

1.2.3 Shortages of system security can have severe consequences

Despite best endeavours, the power system can, on rare occasions, experience cascading failures resulting in loss of supply to large portions of the power system. Recent examples – including on the Iberian Peninsula and Chile in 2025, Brazil in 2023 and 2018, and South Australia in 2016 – demonstrate how failures to maintain sufficient system security can lead to widespread blackouts with severe consequences.

A review by ISON[22] highlights the growing complexity and vulnerability of modern electricity grids, such that relatively modest unexpected events – such as voltage oscillations, maloperation of protection equipment, or fault ride-through settings – can cause cascading failures. It also emphasises the urgent need to rethink restoration planning such that system restoration remains feasible and timely (see Part C Section 8.2 for discussion).

1.2.4 System security risks are asymmetric

The potential severity of system security shortage creates an asymmetric risk profile in terms of early rather than late action and over- and under-investment, as described in the box below.

The period of infrastructure renewal and technology change in the NEM presents a heightened risk profile for system security. This is due to uncertainties associated with what asset and technology changes might occur, when, and the practicalities of commissioning new large infrastructure.

Major uncertainties include the timing of network augmentation, delivery of synchronous condensers and new generators, potential exit or connection of large loads, dependability of new technologies in providing certain security services, regular or seasonal decommitment of coal units under flexible operating regimes, changes to exit timing or unexpected plant failure. Statistically, failure rates increase as plants near the end of their planned operational life, as **Figure 5** shows.

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[22] See https://www.aemo.com.au/-/media/files/about_aemo/international-system-operator-collaboration/international-system-restoration-review.pdf.

Asymmetry of system security risks

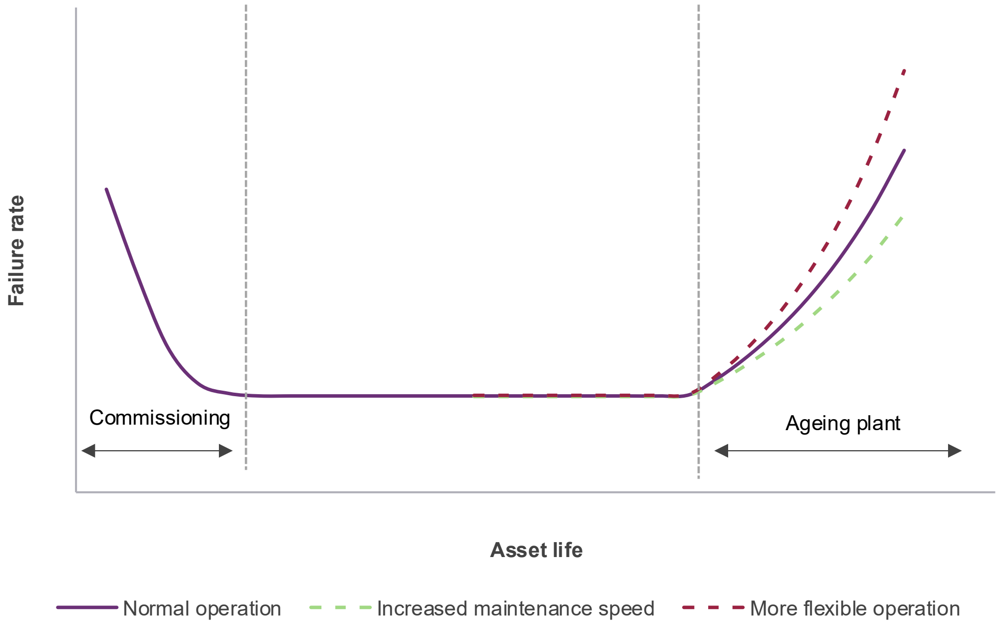
AEMO recognises the potential for both over- and under-investment in system security and the complexity of striking the right balance between appropriate investment and risk mitigation.

As discussed in Section 1.3, AEMO may be forced to intervene to maintain system security at times when the market does not provide sufficient system security. These interventions may include contracts, directions and, if required, more severe measures (see Section 1.3.1). Inadequate resources can also lead to higher market costs and leave the system more vulnerable to cascading failures (see Section 1.2.3).

Such interventions may come at a considerable cost to consumers, and do not contribute to investments in infrastructure that would support security long term. In contrast, assets that are delivered earlier than required may be economically inefficient (although not necessarily more so than interventions) but provide value to consumers by enhancing the system in the lead up to when they are required.

AEMO's view is that system security shortages therefore pose an asymmetric risk because the consequences of shortages – which arise from under-investment or late action or delivery – are more severe than the potential costs of early or over-investments delivering assets ahead of time.

Figure 5 Example bathtub curve for failure rates over asset lifetime



AEMO's recent 2025 *Thermal Audit*[23] evaluated current capabilities and risks for the NEM's main thermal power plants. For coal-fired plant, the report highlighted a clear correlation between increased operational flexibility and higher maintenance costs to maintain existing levels of availability. While greater operational flexibility can help manage certain system conditions such as Minimum System Load (MSL) (see Part C Section 9.19 and Appendix A3 for discussion), this flexibility is also expected to raise failure rates and may introduce new failure modes. For stations near the end of their planned

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[23] At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/2025-thermal-audit.pdf.

operational life, failures that are uneconomic to repair for a short residual lifespan are more likely to occur, with a risk that key assets suddenly become unavailable earlier than expected.

Another source of uncertainty is the behaviour of new plant. This includes teething issues during commissioning – as shown at the left of the curve in **Figure 5** – as well as risks of new failure modes and unforeseen plant interactions.

Large loads, such as aluminium smelters, also have significant impacts on system security. Their large and relatively steady demand profiles help mitigate the challenges of MSL (see Part C Section 9 and Appendix A3 for discussion) and are often incorporated into emergency load shedding and restart schemes.

The decommitment or closure of each existing large load represents a material transition point for the NEM, in some cases triggering additional network investment to support system operation in its absence. In addition to the transition points studied in Part B, AEMO is assessing the impacts on system security for each existing large load and working closely with relevant TNSPs and governments where risks are identified.

Outage management

Power system operability is complicated in real time by the requirement for planned outages and the occurrence of unplanned outages. AEMO is observing a growing need to take multiple network outages to connect new generation and network assets, perform maintenance, and upgrade plant (such as modifications to improve the operational flexibility of synchronous generators).

Major outages require extensive planning, coordination and mobilisation of specialist resources. Depending on their location and timing they can pose significant security risks. Although AEMO has powers to defer transmission outages and request rescheduling of generator outages where these threaten system security, these actions can have costs and significant flow-on effects on subsequent outage schedules, unplanned outage risks, or the installation and connection of new assets.

AEMO actively considers outage management through the Medium Term Projected Assessment of System Adequacy (MT PASA), as well as in the 2025 *Electricity Statement of Opportunities* (ESOO)[24], seeking engagement with individual generators on their planned outages for near term transition points (such as Eraring closure), and enabling the study of system typical conditions under the NSCAS framework[25]. In future, improving general visibility of planned generator and transmission outages across industry, and operational tools for coordinating outages would ensure outage needs can be met while maintaining power system security.

Prudent response to heightened, asymmetric security risks

Situations where there are limited or insufficient options to manage system security carry the risk of large costs and consequences for consumers (see Section 1.2.3). During the next 10 years, the extent of changes facing the NEM will make the management of power system security challenging at times, with high dependency on the timing of new assets being delivered. The additional demands for generation and transmission outages further exacerbate these challenges. Accordingly, prudent investments should be considered that help improve resilience and redundancy where it is in the long-term interests of consumers to do so.

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[24] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf.

[25] At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-nscas-report.pdf.

Given the heightened and asymmetric nature of the system security risk profile through the transition, it is often prudent, in the long-term interest of consumers, to act early on low-regret actions. Actions are considered low-regret if, with a high degree of confidence, they will be:

- effective at meeting system security needs – under forecast conditions and a wide range of plausible alternative future system conditions, and
- necessary in the medium term – perhaps somewhat later (or earlier) than forecast.

To support such actions, AEMO is flagging risks and consequences around each upcoming transition point in Part B of this report. Outlining the actions needed to appropriately manage the transition point.

This information is provided to inform investments and other preparatory actions by all the stakeholders that have shared responsibility for maintaining security (see Section 2.1). Decisions to take action are ultimately made by governments, market participants, or network service providers (NSPs) and, to the extent these actions involve investment in regulated assets, the Australian Energy Regulator determines whether they are prudent and efficient.

Reform of regulatory regimes may further assist in promoting efficient investments with regard to the asymmetric and heightened risks of the transition (see Section 2.4).

1.2.5 System security criteria

AEMO's power system security responsibilities are set out in the NER[26] and system standards[27], and implemented through guidelines and procedures[28].

While noting that security is a property of the system, not its parts, AEMO's Engineering Roadmap[29] assesses security using five criteria: system strength, frequency and inertia, voltage control, transient and oscillatory stability, and system restoration. These criteria are used throughout this report to assess the current and future security of the power system, with detailed descriptions in **Table 4** below. While transient and oscillatory stability is assessed at a high level in this year's report, it is expected to receive greater emphasis in future reports.

Many power system phenomena can change extremely rapidly, for example in milliseconds after a disturbance, pushing the system towards the limits of the technical operating envelope. Their management therefore requires the use of automated systems – embedded in generators, transmission infrastructure, loads and control centres – in addition to operational procedures and planning.

Beyond immediate automated responses, manual actions may also be required from operations staff in AEMO, TNSP and market participant control rooms. The ability to operationally respond to dynamic changes in the power system, to keep the system in a secure state, is referred to as *operability*. As the physical power system evolves, the tools operators require to manage security also need to evolve. AEMO is responding to this need by investing in a significant uplift in AEMO's operational tools (see Section 1.3.3). NSPs will also need to invest in significant uplifts. The National CER Roadmap

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[26] At https://energy-rules.aemc.gov.au/ner/429/187180#4.3.1.

[27] Standards for the performance of the power system as set out in NER Schedule 5.1a, and power system security standards determined by the Reliability Panel, defined in NER 8.8.1(a)(2).

[28] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation and https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf.

[29] At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.

workstream to *Redefine roles for market and power system operations*[30] is working to formalise distribution system roles and responsibilities, considering distribution network service providers (DNSPs) and other actors. In addition, AEMO is working with TNSPs and the Australian Energy Regulator (AER) to help frame a complementary statement of future TNSP competencies and capabilities.

As noted in Section 1.1.1, in addition to being secure, the power system must be *reliable*. To give an integrated view, this report draws on findings from AEMO's ESOO[31] and *Gas Statement of Opportunities* (GSOO)[32] with regards to reliability and gas supply adequacy risks.

Table 4 Power system criteria and their contributions to security

System criteria	Contributions to system security
System strength	System strength is the ability of the power system to maintain and control the voltage waveform at any location during both steady-state operation and following a disturbance. This definition reflects AEMO's *Power System Requirements*[A] and underpins the system strength reforms introduced through the AEMC's 2021 Efficient Management of System Strength rule change[B]. The current system strength management framework consists of two complementary requirements, set out in NER S5.1a.9 and implemented through AEMO's *System Strength Requirements Methodology*[C]: • minimum three-phase fault level (system security requirement), and • stable voltage waveforms (efficient level to host forecast IBR). Each requirement plays a distinct role: minimum fault levels ensure reliable protection operation and system security, while stable voltage waveforms support the secure operation and connection of IBRs. These requirements are assessed at designated system strength nodes and may be further refined as technology and understanding evolve. Throughout this report, including Part B and Appendix A2, the requirements are distinguished wherever system strength is discussed. For more details, see the call box on the following page.
Frequency and inertia	In an alternating current (AC) power system, frequency reflects the balance between active power generated and consumed. AEMO is responsible for managing power system frequency and time error in accordance with the Frequency Operating Standard[D]. For system security, a particularly important characteristic is how rapidly the frequency changes in response to a disturbance, referred to as the rate of change of frequency (RoCoF), and, relatedly, how quickly and reliably the fleet of connected generators adjust their power output to stable levels. The RoCoF is inversely proportional to the inertia[E] of the system, which includes the physical inertia of the spinning masses inside synchronous machines and the emulated 'synthetic' inertial response that IBR may be programmed to produce. Inertia impacts the overall system dynamic performance, particularly frequency stability, and interacts with other forms of stability, both local and global. Inadequate frequency control and excessive RoCoF can cause plant disconnection and/or plant damage.
Voltage control	Voltage control is the ability to manage reactive power in an AC power system to maintain network voltages profile and variation within defined limits under normal and contingency conditions, across a range of demand levels. It requires coordinated use of generator reactive capability, network reactive plants, and other voltage control devices to support secure power transfer and voltage stability. Voltage control is influenced by minimum three-phase fault level, particularly regarding the magnitude of voltage step changes following the switching of a large reactive device. AEMO also assesses voltage step changes based on the limits, according to AEMO's *System Strength Requirements Methodology*. Adequate dynamic reactive headroom is maintained to ensure acceptable voltage outcomes across the system in the event of a contingency. Reactive power margin is maintained based on prevailing system loading conditions, network topology, and the severity of the largest credible contingency. Voltage instability can lead to cascading outage situations with loss of load or tripping of transmission lines and other network components through protection action, potentially triggering generator loss of synchronism and frequency instability. In real time, AEMO primarily utilises the automated VAr Dispatch Scheduler (VDS) system to dispatch TNSP and generator reactive power devices in the NEM to meet specified voltage control objectives[F].
Transient and oscillatory stability	These criteria relate to the ability of the power system to remain stable and in synchronism when subject to small disturbances (oscillatory stability) and large disturbances (transient stability)[G]. This requires the presence of

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[30] See consultation page at https://consult.dcceew.gov.au/national-cer-roadmap-redefine-roles-m3-p5.

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

[32] At https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

System criteria	Contributions to system security
	synchronising torque and damping torque, historically provided by synchronous machines and the ability of asynchronous plant to reach a state of equilibrium after the power system disturbance[H]. It also requires controls to dampen inter-area stability issues, which will need to evolve as the synchronous generators that currently provide these controls retire, and the nature of oscillations changes with new system configurations. Additionally, this requires sufficient voltage waveform stability to ensure new oscillation modes associated with the stability of grid-following inverter-based plant are managed.
System restoration	Despite best endeavours, the power system can, on rare occasions, experience cascading failures resulting in loss of supply to large portions of the power system. Following this, control room operators in the NEM require the ability to restore the power system through the execution of a system restart pathway. Black start generators and restart pathways used in operation during a restart are determined on the day based on available plant, but preferred pathways and key system restart ancillary service (SRAS) providers are agreed in advance with NSPs and generators[I].
Operability	The processes required for securely and reliably scheduling and dispatching the power system in real time to keep the system within its secure technical operating envelope. These include operational forecasting, outage coordination, constraints and dynamic security assessment, reserve management and operator training.
Resource adequacy	Having a sufficient overall portfolio of energy resources and network capacity to continuously achieve the real-time balancing of supply and demand. Potential constraints include thermal limits of the network, reliability of sufficient electricity generation capacity (including considerations of their fuel supplies) and gas adequacy.

A. AEMO's *Power System Requirements* document, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.
B. See https://www.aemc.gov.au/sites/default/files/2021-10/ERC0300%20-%20Final%20determination_for%20publication.pdf.
C. At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.
D. At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715%20Power-System-Security-Guidelines.pdf.
E. At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf.
F. Refer to Section 14 of AEMO Power System Security Guidelines for further information, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf.
G. At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf.
H. At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/power-system-stability-guidelines.pdf?la=en.
I. For more information, see Section 3.4 of AEMO's *Power System Requirements* document, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

System strength is a complex but critical system characteristic. A detailed explanation is in the box below.

System strength

System strength refers to the ability of the power system to maintain and control the voltage waveform at any location during both normal operation and following a disturbance[33].

When large changes in current cause small changes in voltage, the system strength is considered high, and the grid is considered 'strong'. In contrast, when small changes in current cause large changes in voltage waveform, the system strength is low, and the grid is said to be 'weak'. The NEM is a relatively 'long and stringy' power system and many IBR are connecting in peripheral, 'weak' parts of the NEM[34].

Historically, fault level was often used as a proxy for system strength in the NEM, as areas with strong voltage waveforms typically exhibited high fault levels due to synchronous machine characteristics. With the rapid growth of grid-following (GFL) IBR, industry understanding has matured, and it is now clear that protection-quality fault current and voltage waveform stability are distinct technical needs. The NER reflects this by defining a system strength standard with two complementary requirements:

1. a minimum fault level requirement to support protection and power system stability, including the ability to switch reactive plant, and

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[33] See Section 2.1 of https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

[34] See https://www.aemc.gov.au/sites/default/files/2021-10/ERC0300%20-%20Final%20determination_for%20publication.pdf.

2. a stable voltage waveform requirement to enable efficient levels of IBR integration.

Most grid-following inverters' control systems base their actions on local measurements of voltage and current. When system strength is low, inverters' control systems can negatively interact with each other, leading to small disturbances getting out of control quickly, which can escalate into power system oscillation or instability quickly. The specific control systems used by different makes and models of inverters differ significantly, including how they behave in low system strength conditions (see Part C Section 10.1 for AEMO's latest insights on grid-forming inverters).

Most protection equipment similarly bases actions on local measurements of voltage and current. Most such equipment has been designed around the expected fault characteristics (changes in voltage and current waveforms) of synchronous generator dominated power systems, including fault current magnitude and sequence components[35] and voltage phase angles. The specific algorithms or logics used by different makes and models of protection equipment also differ (see Part C Section 10.1.2 for insights from AEMO's 2025 survey of TNSP protection systems).

The current system strength management framework consists of two complementary requirements, set out in NER S5.1a.9 and implemented through AEMO's *System Strength Requirements Methodology*[36]:

- **Minimum three-phase fault level** (minimum requirement for system security):
  - This requirement ensures sufficient fault current to support:
    - the correct and reliable operation of protection systems,
    - stable performance of voltage control systems, and
    - the ability of the power system to remain stable following credible or protected events.
  - Currently in the NEM, minimum three-phase fault levels must be provided by sources of 'protection quality fault current'[37] – such as synchronous condensers and synchronous generators.
- **Stable voltage waveforms** (efficient level set to enable stable operation of new and existing IBR):
  - This requirement ensures that plant does not create, amplify, or reflect instabilities in steady-state conditions, and that voltage waveform instability is not triggered following credible contingencies.
  - Stable waveforms support the secure operation and connection of forecast levels of grid-following IBR, avoiding weak-grid control interactions.
  - Satisfying the stable voltage waveform requirement may require dedicated investments in additional voltage sources (including synchronous machines or grid-forming inverters) and/or network augmentation.

Grid-forming inverters' capabilities to deliver minimum three-phase fault level and stable voltage waveform services, and AEMO's activities to support improved understanding of these, are discussed in Part C Section 10.1.

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[35] During unbalanced faults – for example when one cable contacts the earth – the voltages of a three-phase system are no longer symmetrical. During these periods the voltages (and currents) can be analysed through a mathematical decomposition into three symmetrical components: the positive sequence, negative sequence and zero sequence components.

[36] At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

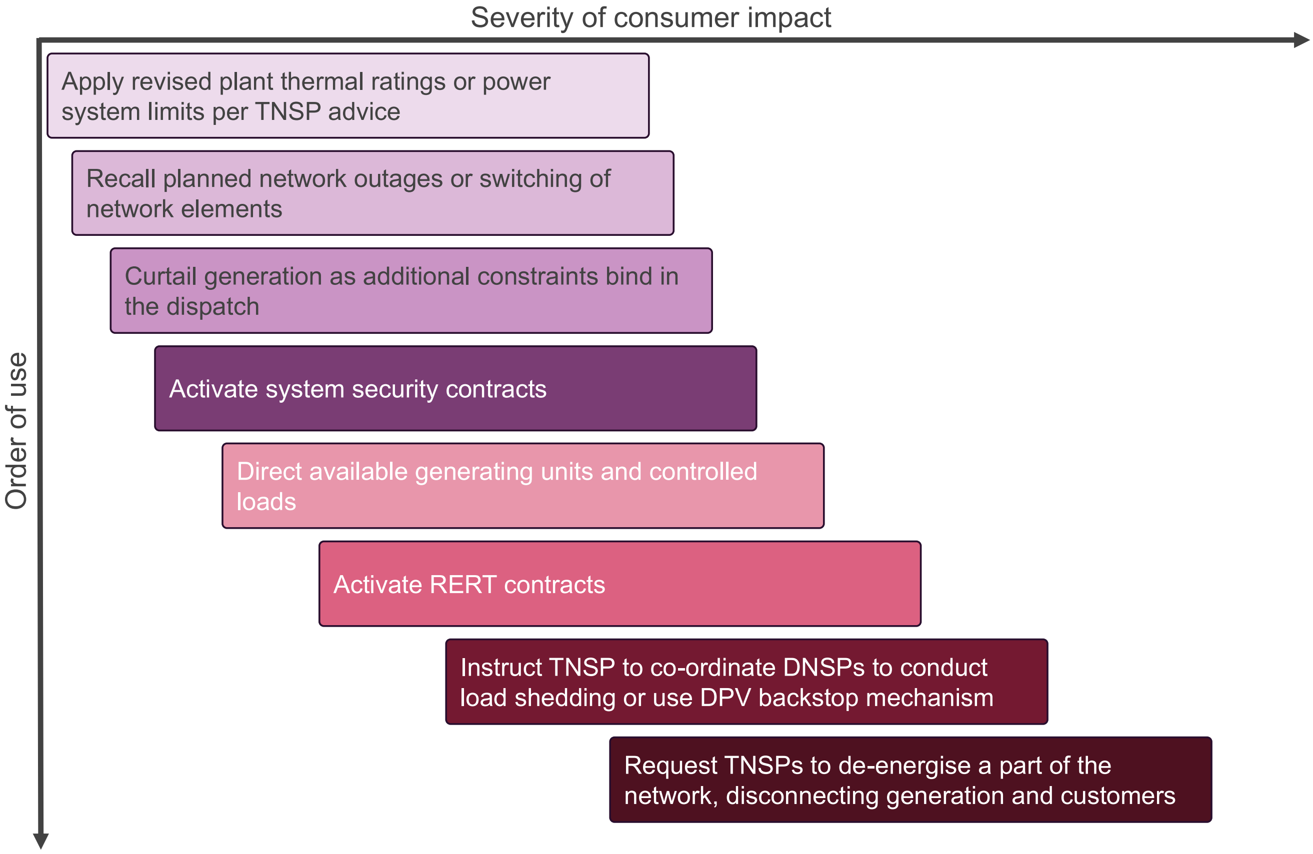
[37] AEMO's May 2024 update to the 2023 ESOO, page 43, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/may-2024-update-to-the-2023-electricity-statement-of-opportunities.pdf.

1.3 Maintaining security is becoming more operationally challenging

1.3.1 AEMO's operational toolkit

When the NEM is in a secure state, with ample availability of system security resources, the system will be resilient to contingencies. If, in contrast, there are scant resources able to provide security services, AEMO may be required to intervene to maintain (or return to) a secure operating state (see Section 1.2.2). The actions that AEMO may need to take are listed in **Figure 6**, in priority order[38].

Figure 6 AEMO's operational tools to maintain security



Interventions are poor outcomes for two reasons – they are costly either directly or through distorting market outcomes, and they do not contribute to new physical assets that would support security in the long term.

Currently, efficient market dispatch will at times not ensure the availability of adequate system security resources. The goal of further developing NEM planning, market, and operating frameworks is to deliver a secure system via the market, as far as practical, and minimise interventions.

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[38] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/procedures/so_op_3715-power-system-security-guidelines.pdf.

1.3.2 Operational metrics

In recent years, market and system conditions have forced AEMO to more regularly issue directions to maintain system security. **Figure 7** shows how this has been particularly pronounced in South Australia, where up to four synchronous units were operating under directions in 2020 and 2021, at cost of up to $35 million per quarter (exclusive of any further indirect impacts). With the delivery of four synchronous condensers completed in 2021, and increasing operational confidence in high IBR contribution scenarios, AEMO and ElectraNet were able to implement new limits advice that enabled system operation with a minimum of two synchronous units online. In 2025, following further technical studies and due diligence, this requirement has been successfully reduced to one synchronous generator (see Part B).

Each of these steps, and the contracting of non-market ancillary service (NMAS) agreements by AEMO, has further reduced the reliance on directions in South Australia. Following Project EnergyConnect Stage 2 and evidence of secure operation, the minimum synchronous generator units may be reduced to zero (this transition point is described in Part B).

In New South Wales and Victoria, AEMO has increasingly needed to resort to issuing directions to maintain system strength over the past three years, as shown in **Figure 8**. There is a risk that, if security investments are not delivered on time and in full ahead of transition points, the resulting security gaps will need to be addressed through interventions: primarily through TNSP system security contracts, or, where gaps remain and AEMO has powers, by AEMO contracts, or, failing this, AEMO directions. The goal of further developing NEM planning, market, and operating frameworks is to minimise the need for such interventions and deliver a secure system via the market, as far as practical, ahead of time.

Figure 7 Number of units under direction in South Australia and the cost of these directions

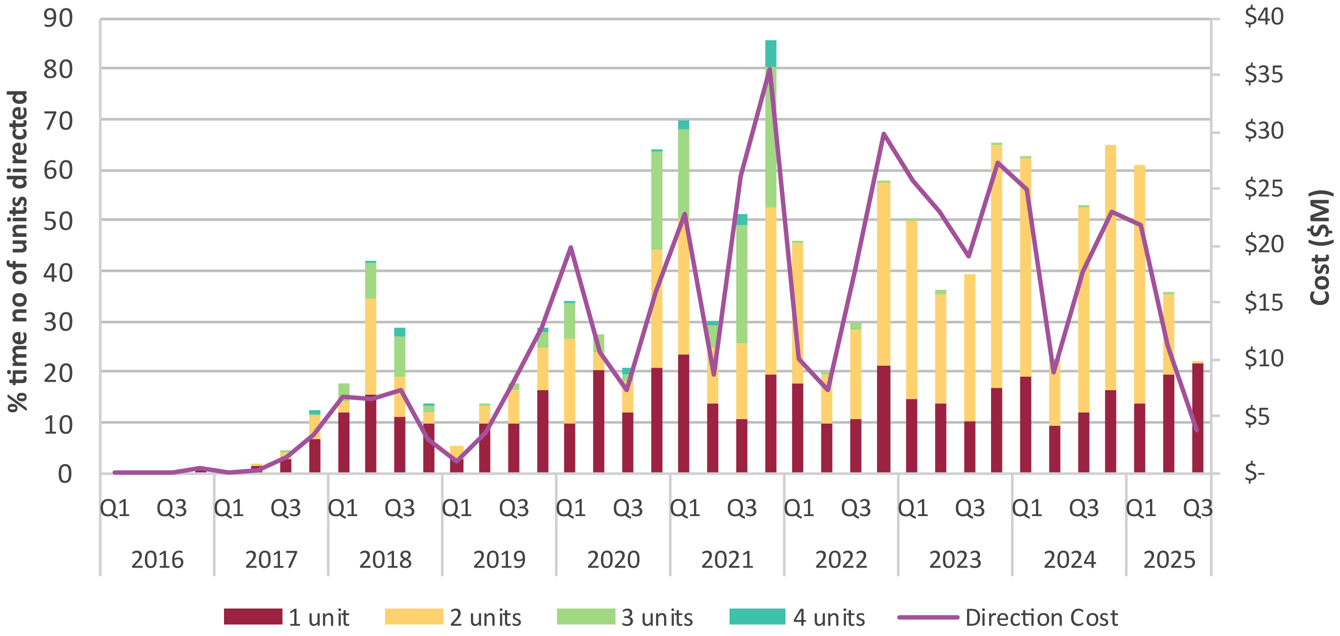
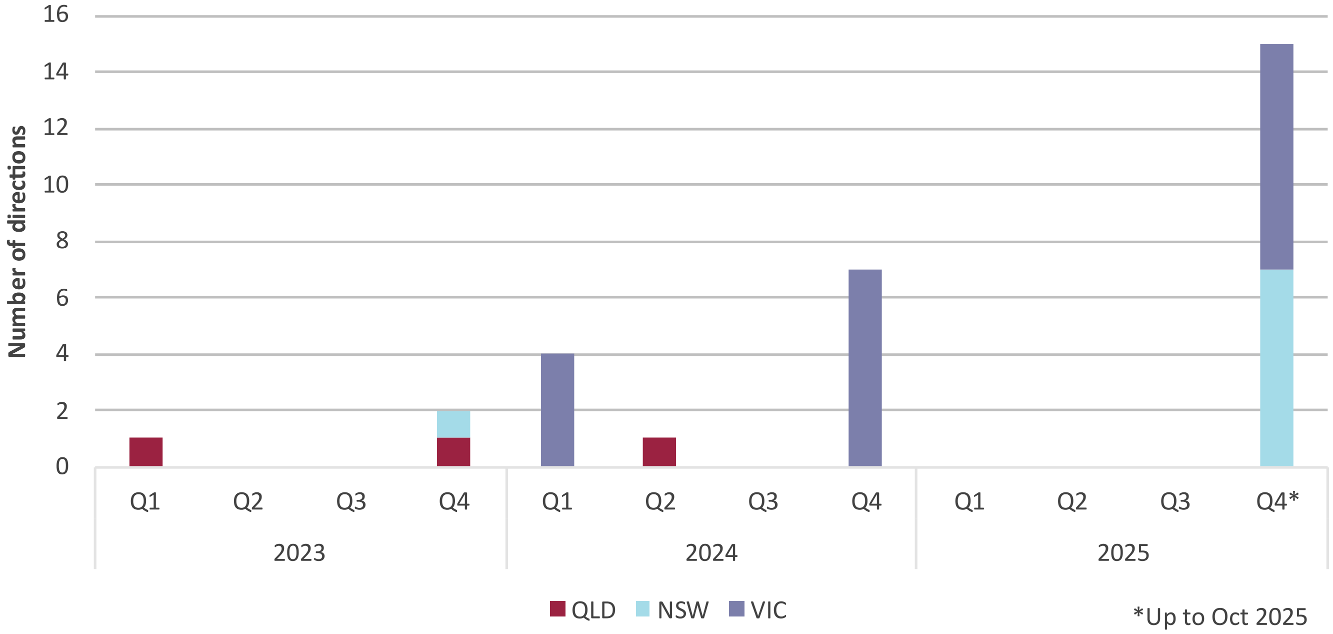


Figure 8 Number of directions in New South Wales, Queensland and Victoria



Another metric that AEMO tracks is the maximum contributions[39] of renewable energy sources to instantaneous demand (over a 30-minute interval). As shown in **Figure 9**, these contributions have steadily increased with time, to a current record of 78%. At these times, the NEM is operating with little synchronous generation. **Figure 9** also shows the average and maximum potential[40] renewables contributions. The maximum potential contribution has exceeded 100% on numerous occasions, indicating that all NEM demand could have been supplied by renewables were it not for network and system security constraints and/or economic curtailment. This underscores the role efficient investments in security can play in facilitating the transition to the least-cost, low- or zero-emissions power system.

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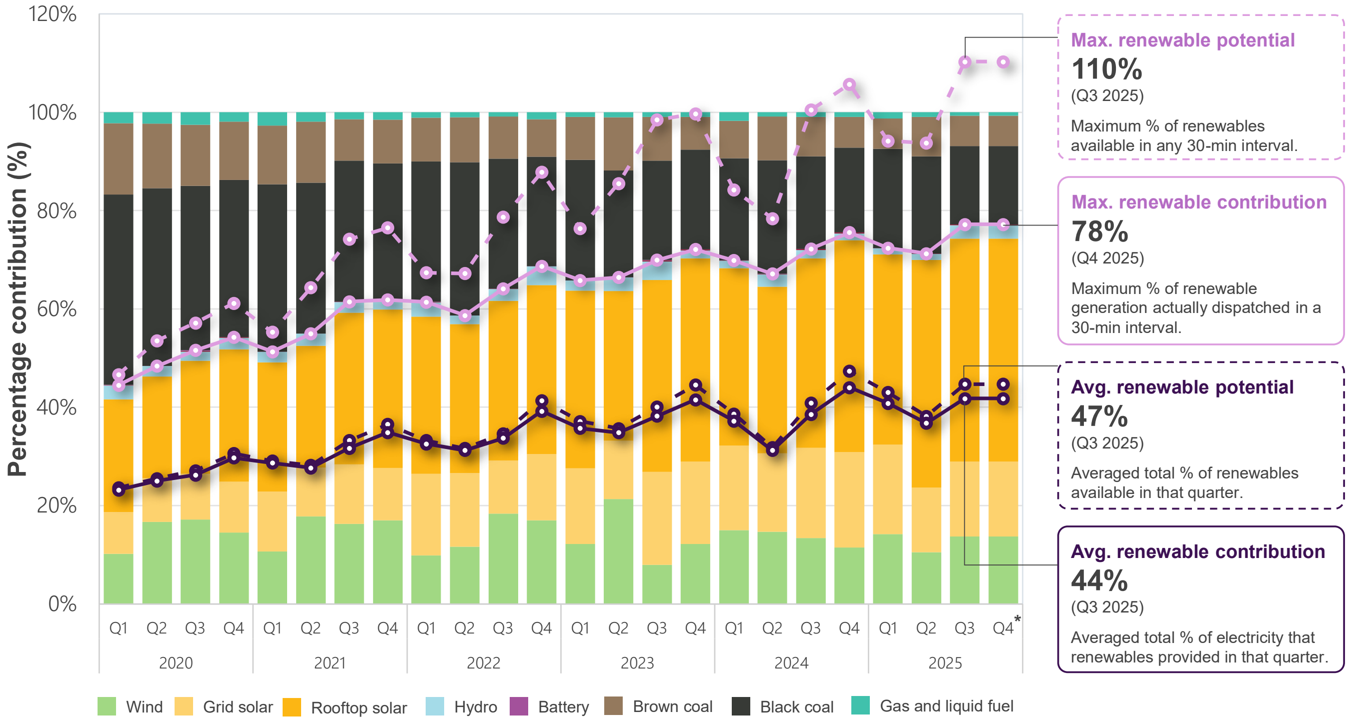
[39] Peak renewable contribution is calculated using the renewable share of total generation. This measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for distributed PV. Renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery discharge and distributed PV. Total generation = large-scale generation + estimated PV output.

[40] Renewable potential in an operating interval refers to the total available energy from variable renewable energy (VRE) sources, even if not necessarily dispatched, and actual output from dispatchable renewables, expressed as a percentage of the total NEM supply requirement.

Figure 9 Maximum contributions of renewables to NEM demand



Max. renewable potential
110%
(Q3 2025)
Maximum % of renewables available in any 30-min interval.

Max. renewable contribution
78%
(Q4 2025)
Maximum % of renewable generation actually dispatched in a 30-min interval.

Avg. renewable potential
47%
(Q3 2025)
Averaged total % of renewables available in that quarter.

Avg. renewable contribution
44%
(Q3 2025)
Averaged total % of electricity that renewables provided in that quarter.

1.3.3 Uplift in operational capabilities

As the operating environment continues to evolve, AEMO is deploying tools and processes to securely integrate emerging technologies into increasingly complex systems. Through the implementation of the Improved Security Framework (ISF) rule change, AEMO is building capabilities to monitor and respond to system strength, inertia, and fault levels. These new functions are being embedded into operational workflows via structured training and bespoke tools.

As Australia's energy transition continues, and the power system and markets continue to evolve, there is a continued need to further develop operational capabilities including technologies and tools to ensure continued security and reliability. Essentially, the transition introduces a range of new operating conditions which must be managed in the control rooms and wider operations through a range of new procedures, data, technologies, capability uplift and new market mechanisms. These include managing:

- new power system phenomena driving new data, monitoring and modelling tools requirements,
- increased resource variability and complexity driving new procedure requirements, forecasting and system upgrades, and
- more complex, dynamic and changing interfaces with an increasing number of market participants, and network businesses meaning changing roles and responsibilities, operational limits, and outage coordination requirements. These are driving new interface requirements, new data and capability requirements along with a need for automation and consideration of approaches to visualisation to manage cognitive overload for operators and decision-making.

AEMO's Operational Technology Program (OTP)[41] is central to this effort. As part of this program, a significant review of AEMO's required operational capabilities is currently underway to understand the requirements during the transition. To support this, independent benchmarking by the Electric Power Research Institute (EPRI) has been completed to understand international best practice and ensure that AEMO can securely and reliably manage operations into the future. This has confirmed that there are gaps in the operational capability required for the future and that there are technology investment opportunities to reduce the operational risks for current and future operations. This review is being considered in conjunction with the transition planning requirements for Australia and a plan is being developed for future operations technology requirements.

As part of planning for future operations technology, AEMO is adopting a whole-of-system approach and is engaging with network businesses to understand and plan the wider technology requirements into the future. This co-ordination will continue over the coming years to ensure an efficient and robust approach.

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[41] See https://www.aemo.com.au/initiatives/major-programs/operations-technology-program.

2 How AEMO is planning for system security in the transition

Many stakeholders share responsibility for security in the NEM. AEMO's transition planning activities identify and assess transition points, events and milestones that require material changes in the operational approach to maintaining security. This technical work is complemented by numerous active policy reforms and informed by stakeholder feedback and engagements.

2.1 Responsibility for security is shared by many stakeholders

Managing power system security is a complex task. Security depends on many system criteria (see Section 1.2.5) across planning and operational timeframes (see Section 1.3.1 and 2.2.2). The responsibilities for maintaining security are similarly complex, with roles and responsibilities for many stakeholders – including AEMO, NSPs, market participants, investors, governments, regulators, and customers – who must act with coherence, making decisions years in advance based on available information.

Figure 10 presents the AEMC's outline of the responsibilities and frameworks for power system security under the NER[42]. **Figure 11** complements this with a detailed breakdown of stakeholder actions involved in setting technical requirements, assessing economic options, and operationally delivering services to manage security criteria. It highlights some of the dependencies of planning activities on TNSP inputs (such as limits advice) and the risks that procurers cannot, or do not, secure enough services from providers (for instance if there are not sufficient sources of black start services).

AEMO notes that distribution network service providers (DNSPs) also have critical system security responsibilities. DNSPs are becoming increasingly important actors for managing system security in a high DER power system. As discussed in Part C Section 9.2, AEMO is working closely with DNSPs on the capabilities required to do this, with associated roles, responsibilities and operational coordination requirements being considered in the National CER Roadmap[43].

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[42] See https://www.aemc.gov.au/sites/default/files/2025-03/2025.3.14%20ESS%20slides.pdf.

[43] See https://consult.dcceew.gov.au/national-cer-roadmap-redefine-roles-m3-p5.

Figure 10 AEMC schematic of frameworks and responsibilities for system security

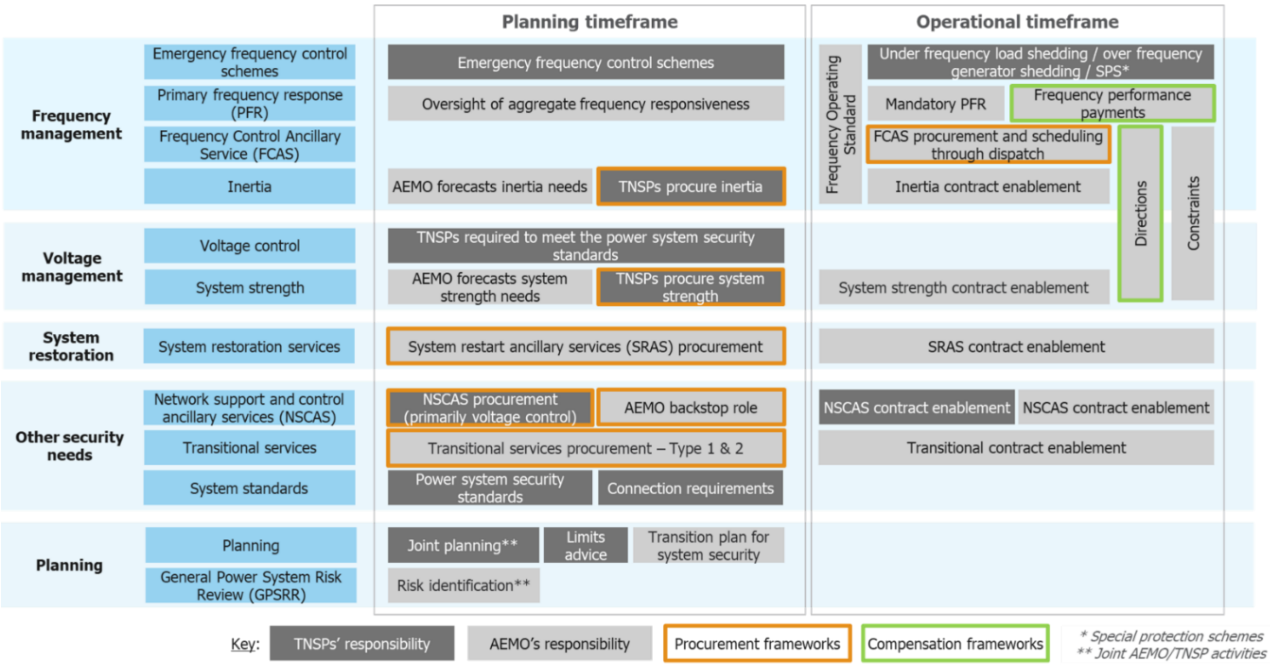
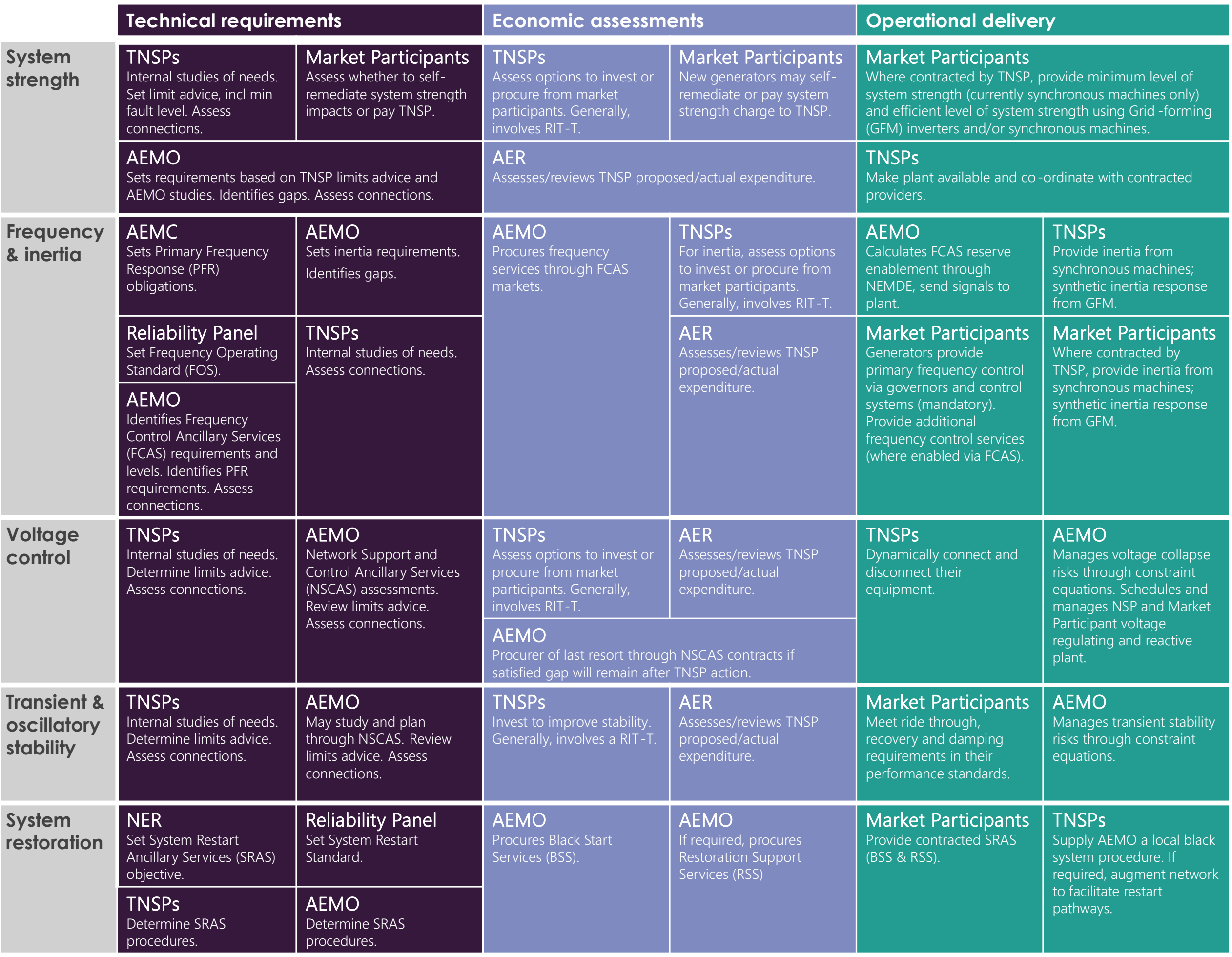


Figure 11 Roles and responsibilities in maintaining security assets in the long-term interest of consumers



	Technical requirements		Economic assessments		Operational delivery	
System strength	**TNSPs** Internal studies of needs. Set limit advice, incl min fault level. Assess connections.	**Market Participants** Assess whether to self-remediate system strength impacts or pay TNSP.	**TNSPs** Assess options to invest or procure from market participants. Generally, involves RIT-T.	**Market Participants** New generators may self-remediate or pay system strength charge to TNSP.	**Market Participants** Where contracted by TNSP, provide minimum level of system strength (currently synchronous machines only) and efficient level of system strength using Grid -forming (GFM) inverters and/or synchronous machines.	
	AEMO Sets requirements based on TNSP limits advice and AEMO studies. Identifies gaps. Assess connections.		**AER** Assesses/reviews TNSP proposed/actual expenditure.		**TNSPs** Make plant available and co-ordinate with contracted providers.	
Frequency & inertia	**AEMC** Sets Primary Frequency Response (PFR) obligations.	**AEMO** Sets inertia requirements. Identifies gaps.	**AEMO** Procures frequency services through FCAS markets.	**TNSPs** For inertia, assess options to invest or procure from market participants. Generally, involves RIT-T.	**AEMO** Calculates FCAS reserve enablement through NEMDE, send signals to plant.	**TNSPs** Provide inertia from synchronous machines; synthetic inertia response from GFM.
	Reliability Panel Set Frequency Operating Standard (FOS).	**TNSPs** Internal studies of needs. Assess connections.		**AER** Assesses/reviews TNSP proposed/actual expenditure.	**Market Participants** Generators provide primary frequency control via governors and control systems (mandatory). Provide additional frequency control services (where enabled via FCAS).	**Market Participants** Where contracted by TNSP, provide inertia from synchronous machines; synthetic inertia response from GFM.
	AEMO Identifies Frequency Control Ancillary Services (FCAS) requirements and levels. Identifies PFR requirements. Assess connections.					
Voltage control	**TNSPs** Internal studies of needs. Determine limits advice. Assess connections.	**AEMO** Network Support and Control Ancillary Services (NSCAS) assessments. Review limits advice. Assess connections.	**TNSPs** Assess options to invest or procure from market participants. Generally, involves RIT-T.	**AER** Assesses/reviews TNSP proposed/actual expenditure.	**TNSPs** Dynamically connect and disconnect their equipment.	**AEMO** Manages voltage collapse risks through constraint equations. Schedules and manages NSP and Market Participant voltage regulating and reactive plant.
			AEMO Procurer of last resort through NSCAS contracts if satisfied gap will remain after TNSP action.			
Transient & oscillatory stability	**TNSPs** Internal studies of needs. Determine limits advice. Assess connections.	**AEMO** May study and plan through NSCAS. Review limits advice. Assess connections.	**TNSPs** Invest to improve stability. Generally, involves a RIT-T.	**AER** Assesses/reviews TNSP proposed/actual expenditure.	**Market Participants** Meet ride through, recovery and damping requirements in their performance standards.	**AEMO** Manages transient stability risks through constraint equations.
System restoration	**NER** Set System Restart Ancillary Services (SRAS) objective.	**Reliability Panel** Set System Restart Standard.	**AEMO** Procures Black Start Services (BSS).	**AEMO** If required, procures Restoration Support Services (RSS)	**Market Participants** Provide contracted SRAS (BSS & RSS).	**TNSPs** Supply AEMO a local black system procedure. If required, augment network to facilitate restart pathways.
	TNSPs Determine SRAS procedures.	**AEMO** Determine SRAS procedures.				

2.2 AEMO's transition planning activities

Recent rule changes, particularly the ISF rule change[44] and subsequent NER 5.20.8 'Publication of Transition Plan for System Security'[45], have extended AEMO's planning activities with a dedicated and holistic focus on key transition points. This complements AEMO's long-standing system planning functions, which are focused on distinct security criteria.

Transition planning focuses on continual enhancement of operational readiness, preparing for upcoming transition points while continually assessing the end state of the transition. Transition points are events and milestones that require material changes in the operational approach to managing power system security, such as coal exits and minimum system load thresholds, needing detailed analysis, risk assessment, and cross-functional coordination to plan, and manage. The *Transition Plan for System Security* is an annual report on these activities that outlines AEMO's preparatory actions and seeks to inform proactive investment for medium-term challenges, and provides signals to stakeholders on nearer-term system security risks.

This section outlines how AEMO, in collaboration with TNSPs, defines transition points, and how transition planning takes different shapes for nearer-term (0-2 year) operational planning and more distant future planning horizons, with the difference between transition planning and the transition plan detailed in the box below.

Transition planning is an ongoing, proactive workstream to ensure operational readiness for every transition point.

The *Transition Plan for System Security* is an annually-updated report of transition planning efforts and current technical understanding of what is needed to maintain and achieve power system security in a low- or zero-emissions power system, to inform proactive planning, investment and reform.

2.2.1 Transition points

Transition points are events and milestones that require material changes in the operational approach to managing power system security. These require detailed analysis, risk assessment, and cross-functional coordination to plan, and manage.

AEMO uses a transition point framework, with the definition in the box above and examples in **Table 5**, to focus activities on preparing for events and milestones. As the system evolves, successful navigation of such changes requires joint consideration of both system security and other operational requirements as an integrated process.

Table 5 Definition and examples of transition points

Types of material changes	Examples of material changes
• Cannot be managed efficiently with existing processes (for example, when existing power system operational procedures and normal market operation are not sufficient, or when new capability, staff or skills in AEMO or TNSP control rooms are needed). • Require coordinated and concerted efforts to reform processes or require a NER change to be able to manage the change.	• Major changes to the asset mix, technical envelope, or configuration in the NEM, such as retirement of large synchronous generators, closure or entry of large loads, material investment in new assets to provide security services, or network augmentations, such as new transmission lines and new control schemes.

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

[45] At https://energy-rules.aemc.gov.au/ner/656/608800.

Types of material changes	Examples of material changes
• Changes that are likely to cause AEMO to intervene in the market more than once every two months to maintain reliability or power system security. • Changes that trigger complex joint planning requirements, exceed the defined Material Inter-Network Impact Criteria or which trigger complex Joint planning/approach to manage.	• Threshold events, such as projected seasons where operational demand could drop below minimum levels. • Operational shifts as changes in available security mechanisms allow relaxation of constraints such as minimum numbers of online synchronous generators. • Transition to new operating frameworks, where there is a potential need for monitoring and/or the potential to revert to a prior operating point or system constraint.

AEMO may choose to assess a set of similar or linked transition points collectively, where this is more efficient and provides clearer insights to inform investments, process and regulatory change, or required capabilities, for example, where multiple coal closures are forecast in a similar period, but timing and sequence are uncertain. On longer horizons (such as over five years), where there is less certainty in the specifics of how and when a transition point might unfold, AEMO's focus is on identifying any large or long lead time investments that may be needed to support a particular transition point. As time progresses and uncertainty reduces, AEMO's assessments evolve to be more specific with a shift in focus from long term preparatory actions to operational readiness. Correspondingly, the technical analysis performed also evolves as the transition point approaches (see Section 2.2.3).

2.2.2 Horizons

AEMO's transition planning activities have varying objectives and characteristics in the nearer-term operational planning timeframes and more distant future planning horizons. The *Transition Plan for System Security* uses three horizons, which are described in this section and summarised in **Table 6**.

Table 6 Three horizons of transition planning

	Horizon 1 – Operational planning	Horizon 2 – Transition planning	Horizon 3 – Future system needs
Timeframe	0-2 years	2-10 years	10+ years
Context	Urgency of (near) real time operations, high degrees of confidence in current and near-future operating conditions.	Wide set of possibilities – and higher uncertainty – in how the system may evolve, in terms of expected system configuration, challenges and the prospective preparatory actions.	AEMO conducts assessments of emerging technologies and future power system requirements through the Engineering Roadmap program.
Purpose	Preparing for imminent transition points.	Assessing transition point readiness and risks to inform preparatory actions and investment.	Identify and begin framing risks and opportunities to prepare for anticipated power system conditions outside Horizon 2 timeframe.
Potential actions	Quantifying risk profiles. Preparing operation procedures and contracts (including NSCAS and Type 1 Transitional Services), predominantly using existing assets, technologies and rules.	Risk assessments and studies to inform and contribute to the delivery of prudent investment, and support reform activities. Accelerate operational confidence in, and deployment of technologies, including through use of Type 2 Transitional Services.	Studies and trials that progress readiness of emerging technologies to meet future power system needs. Future-back analysis to enhance understanding of the needs of a low- or zero-emissions power system.

Based on Reliability Panel and stakeholder feedback to the 2024 *Transition Plan for System Security* that planning and procurement processes may require more than five years, AEMO has extended Horizon 2 to cover a two-to-10-year ahead timeframe (previously two-to-five years). While it may appear that there is less urgency to act on Horizon 2 transition points, the long lead times of regulatory approvals, investment decision-making, global supply chains and project delivery means the ‘last time to act’ for transition points in this horizon is often imminent.

Horizon 3 has also been extended, from five+ years to 10+ years. AEMO’s Horizon 3 activities are undertaken through AEMO’s Engineering Roadmap which are currently reported on in annual reports[46], and from 2026 onwards will be integrated in the *Transition Plan for System Security*.

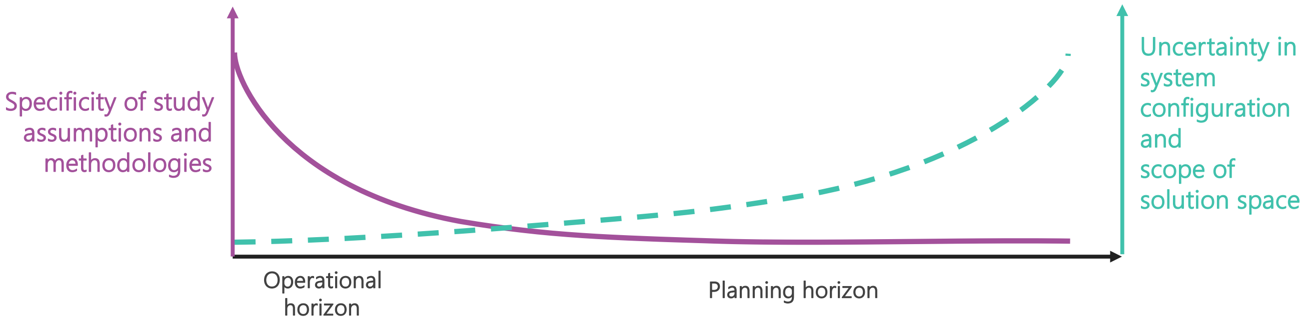
2.2.3 Technical analysis across time horizons

AEMO continuously monitors expected changes in the power system, scanning for risks, forecasting requirements, developing scenarios, and identifying major events – transition points – that require concerted analysis and preparation.

AEMO adopts different analysis approaches appropriate to the information and modelling tools available across time horizons. These seek to balance competing considerations of uncertainty in future system configuration and technological capability against the last time to act, which long delivery times may force to occur while there is significant uncertainty in system configuration, thereby restricting the utility of certain studies.

As uncertainty in the future state (and study inputs) is higher for longer time horizons, the specificity and technical rigour of analysis is consequentially lower, limiting the ability of this analysis to inform forward decision making. For example, there is little value in modelling micro-second phenomena influenced by IBR control settings when the largest source of uncertainty in the model is with the location and timing of delivery of the identified plant. This trade-off is presented in **Figure 12**, with an example for assessing minimum fault levels for system strength.

Figure 12 Representation of system uncertainties versus modelling granularity across planning and operational horizons



<table>
<tr><td rowspan="4">System strength</td><td></td><td>0 – 2 years</td><td colspan="2">2 – 5 years</td><td colspan="3">5 – 10 years</td></tr>
<tr><td>Example uncertainties</td><td>Market behaviour, unplanned outages, weather</td><td colspan="2">Delivery of existing project pipeline, coal decommitment, planned outages</td><td>Policy & reform</td><td colspan="2">Major network augmentation, major new generation, demand, storage capacity</td></tr>
<tr><td>Example solutions</td><td>Directions, contracting</td><td colspan="2">Conversion of existing units
New gas turbine capable of operating in dual mode (as synchronous condenser and generation)</td><td colspan="3">New synchronous condenser build
New technological capabilities</td></tr>
<tr><td>Example studies</td><td>Dynamic studies to confirm stability of existing IBR</td><td>Steady state fault level studies to assess shortfalls against TNSP planning requirements</td><td colspan="3">Market modelling to assess whether system strength requirements are met by market</td><td>Assess system strength requirements on basis of TNSP planning advice</td></tr>
</table>

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[46] See https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap/reports-and-resources.

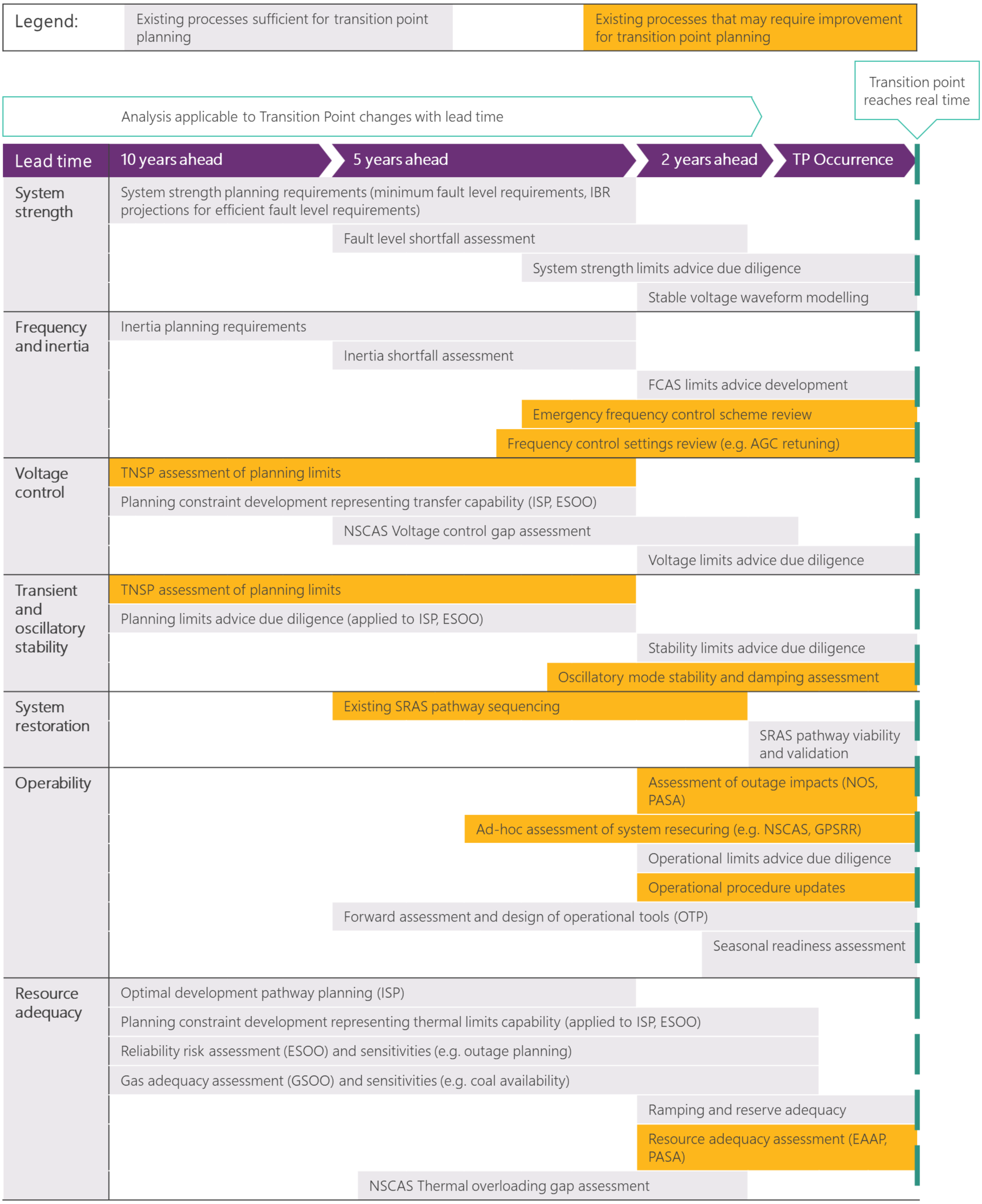
At times, studies with limited accuracy may be sufficient to enable decisions to be made that help manage asymmetric forward risks, particularly for those that require investment in and delivery of long lead time assets, but any identified solutions must be robust against uncertainties in the analysis used to inform decisions.

Figure 13 outlines detailed analyses that AEMO performs to some extent and is evaluating for enhancement within the Transition Planning framework, at various stages across a 10-year lead time ahead of the transition point. These can occur within existing planning (and operational planning) frameworks, or as dedicated analysis once a transition point has been identified. In many cases, improvements to existing processes are required to ensure coverage of plausible operating conditions arising from the transition point and new phenomena triggered – particularly for transition points that have substantial impact on the availability of operational margins for system security. The exact scope of analysis required for this extension is generally assessed on a case-by-case basis. AEMO is working through how to formalise this framework in 2026 and will collaborate with TNSPs through joint planning exercises.

AEMO is continually improving its transition planning assessment approach, including:

- augmenting scope in existing assessment processes to cover both new phenomena and more nuanced operating conditions that are not typically considered in planning studies,
- determining appropriate inputs and assumptions to apply to assessment given inherent uncertainties,
- developing methodologies to enable assessment of longer-term transition points,
- exploring alternative modelling approaches for system restoration to enable longer term assessment and design of viable system restart pathways at least two to five years ahead of when they may be required, and
- improving modelling capabilities including model accuracy and validation processes, for example enabling oscillatory stability analysis for anticipated changes to the synchronous fleet over Horizon 1.

Figure 13 Indicative transition point analysis framework



2.3 Transitional Services

The 2024 ISF rule change provided AEMO with two new 'Transitional Services' powers to assist in maintaining power system security in the transition to a low- or zero-emissions power system. These services are additional and temporary, being time limited to 2029 for Type 1 Services and 2039 for Type 2 Services, and in Section 1.3 are particularly critical for power system security as coal generators age and approach retirement. In addition to improving system security, Transitional Services are designed to contribute to achieving *emissions reductions targets* and reducing the use – and cost – of directions.

Costs for Transitional Services will be recovered under NER 3.15.6A in line with current NSCAS cost recovery mechanism, with the ability to specify regional beneficiaries if appropriate.

The NER specify two Transition Services in clause 3.11.11(b)(1) and 3.11.11(b)(2)[47], which are referred to as 'Type 1 Transitional Services' and 'Type 2 Transitional Services' respectively. The distinction between the two is broadly consistent with AEMO's distinction between Horizon 1 and Horizon 2 (see Section 2.2.2). Type 1 Transitional Services are focused on addressing near-term challenges without issuing directions. Type 2 Transitional Services are focused on addressing longer-term challenges by proving new, low- or zero-emissions contributions to system security.

2.3.1 Type 1 Transitional Services

Type 1 Services are those needed to fill an identified security need within the next two years to support power system during times of uncertainty during transitional periods, or to fill identified gaps that emerge as installation of reactive and power system stabilising equipment is delivered in a staggered manner.

These are services required for power system security that cannot otherwise be provided by an inertia network service, a system strength service, a market ancillary service or an NMAS. Contracts for the procurement of Type 1 Transitional services may be up to three years in length and must not have a term that extends past 1 December 2029. Information on how AEMO intends to move away from using these contracts is outlined in the description of each proposed service below.

Published Type 1 Transitional Services

In late 2024, AEMO published a Statement of Need to procure Type 1 Transitional Services from battery energy storage systems (BESS) to manage MSL events in Victoria and South Australia ahead of spring 2025[48].

AEMO has signed two Type 1 Transitional Services contracts with BESS owners in Victoria with a charging capacity of 307.50 megawatt hours (MWh). Negotiations were undertaken with BESS owners in South Australia, but no suitable agreements were reached.

In November 2025, AEMO published five additional Statements of Need for Type 1 Transitional Services across the NEM, shown in **Table 7**. Each of these will likely lead to multiple contracted resources to fulfil the Transitional Service requirements.

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[47] At https://energy-rules.aemc.gov.au/ner/714/690727#3.11.11.

[48] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/tenders/2024/msl-transitional-services.pdf.

Table 7 Recently published Statements of Need for Type 1 Transitional Services

Type 1 Transitional Service	Description
Procurement of synchronous generators to provide grid reference in South Australia upon completion of NSCAS contracts	A minimum of at least one synchronous generator is currently required under system normal conditions in South Australia, while more than one may be required under outage conditions, for example when islanding is a credible risk. AEMO is seeking to contract with synchronous generators connected at the 275 kV network in South Australia to provide generation at their minimum output when other synchronous generators are not generating[A]. This service will ensure a single synchronous generating unit is kept online until AEMO has confirmed the conditions under which power system security can be maintained in South Australia with zero synchronous generation online. At a minimum these conditions will include the completion of Project EnergyConnect Stage 2 and its Remedial Action Scheme. AEMO is working with ElectraNet to develop an operational transition plan for the move to zero synchronous generators (refer to Part B).
Procurement of MSL services for flexible load and temporary resecuring service – in New South Wales, Queensland, South Australia and Victoria	As described in the Statement of Need[B], a wide Expression of Interest is to be released for Transitional Services to address MSL risks[C]. Those services offered that fit the framework for Type 1 Transitional Services will be negotiated and contracted for New South Wales, Queensland, South Australia and Victoria. Services offered that fit the framework for Type 2 Transitional Services[D] will be negotiated separately. AEMO sees a long-term need for these services in all regions to manage network constraints, including interconnector flows, however the amount of service required in each region will vary, based on prevailing power system conditions. AEMO anticipates that Type 1 transitional contracts will provide an interim safeguard while market reforms and operational responses to low system demand are developed. AEMO will continue working with NSPs and other stakeholders to ensure appropriate safeguards are in place.

A. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/south-australian-grid-reference-transitional-service
B. At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/minimum-system-load---type-1-transitional-service
C. In MSL2 conditions the power system is one credible contingency away from requiring immediate action from AEMO and DNSPs to increase demand.
D. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services.

Proposed Type 1 Transitional Services

AEMO has not currently identified needs for Type 1 Transitional Services in addition to those listed above, however as a general estimate AEMO intends to enter into up to 10 Type 1 Transitional Services agreements over the coming two-year period. It is anticipated that any given Statement of Need may lead to more than one agreement.

2.3.2 Type 2 Transitional Services

Type 2 Transitional Services are intended to support the trial of new technologies, or a new application of existing technologies, to manage power system security in a low- or zero-emissions power system. AEMO has implemented a Type 2 Services framework, establishing a structured process for identifying, procuring, and trialling transitional services as defined by the ISF rule change[49].

Over the past year, AEMO's focus was on developing the governance and assurance infrastructure to support implementation. A three-stage Type 2 Project Lifecycle was developed in accordance with the Transitional Services Guideline[50] and NER 3.11.12[51], covering identification and prioritisation of trial opportunities, procurement, and delivery. A prioritisation methodology was also developed to assess prospective trials based on their system-security impact, feasibility within program timelines, and expected value for informing future markets and operational readiness.

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

[50] At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/transitional-services/transitional-services-guideline.pdf.

[51] At https://https://energy-rules.aemc.gov.au/ner/714/690715#3.11.12.

Published Type 2 Transitional Services

In October and November 2025, AEMO released five Statements of Need for Type 2 Transitional Services, described in **Table 8**. Each outlines a proposed trial in light of specific system-security challenges, how the trialled capabilities will enable AEMO to maintain power system security in the transition to a low- or zero-emissions power system, and the procurement process for interested participants. Collectively, they address gaps in existing arrangements and form a portfolio that spans system restoration, minimum fault levels, and stability functions.

Table 8 Published Statements of Need for Type 2 Transitional Services

Type 2 Transitional Service	Description
Black Start from Inverter-Based Resources (IBR)[A]	Evaluates IBR-based black start solutions to support system restoration in a low-emissions grid. Outcomes of the trial are expected to inform future restoration pathways, SRAS procurement and guide technology development.
System Restart under High Distributed Photovoltaics (DPV) Conditions[B]	Demonstrates emerging technologies and operational approaches capable of managing DPV/CER reconnection on the system restoration process, particularly where communications infrastructure is unavailable.
Grid-Forming (GFM) Inverter Protection-Quality Fault Current[C]	Assesses whether GFM inverters can provide fault current of sufficient magnitude, duration, and composition (e.g. relevant positive and negative sequence components and waveform properties) for protection relays to operate correctly under diverse system operation and fault conditions.
Zero Synchronous Generation[D]	Demonstrates that inverter-based resources (IBR), either standalone or in conjunction with other grid support plant such as synchronous condensers, are able to maintain system security within a large isolated sub-network without requiring synchronous generation to be online. Insights from the trial are expected to inform future operational planning and technical requirements.
Minimum System Load Transitional Services[E]	Assesses novel approaches to management of MSL in conjunction with proposed Type 1 services, as discussed in Section 2.3.1.

A.See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/black-start-capability-from-ibr.
B. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/system-restart-under-high-dpv-conditions-service.
C. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/grid-forming-inverter-protection-quality-fault-current-trial.
D. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/zero-synchronous-generation-trial.
E. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/msl-transitional-services.

Following publication of these Statements of Need, procurement processes have commenced. The next phase will focus on execution of these initial trials and embedding findings within AEMO's operational frameworks, providing insights on learning to the industry for investment signals, and future market design initiatives.

Under the ISF rule, parties may approach AEMO with unsolicited offers of Type 2 Transitional Services. In December 2024, AEMO received the first such unsolicited offer. In line with AEMO's governance framework, the proposal was evaluated, taking into account alignment with the priorities identified in the 2024 *Transition Plan for System Security*, replicability and system-wide learning, and incremental value. AEMO determined that the proposal did not meet the requirements of the framework.

Proposed Type 2 Transitional Services

AEMO's upcoming priorities for Type 2 Transitional Services focus on supporting secure inverter-based operation in Horizon 2. Another upcoming focus area is progressing work on inter-area oscillation damping, noting emerging exposure to poorly damped inter-area oscillations under high IBR conditions. Over the coming months, AEMO will begin scoping a targeted trial, including early consideration of feasible technologies, operating conditions, and potential delivery partners. AEMO is targeting release of this Statement of Need in Q1 2026.

AEMO is also planning to broaden external engagement to identify further trial opportunities. Increased coordination with NSPs, original equipment manufacturers (OEMs), developers, international system operators, and research bodies will help identify emerging security needs and candidate Type 2 trials.

As AEMO moves into the procurement phase for the published trials, market engagement will also be used to understand participation barriers and identify where additional trial options may be viable. Feedback from prospective providers on technical, commercial or integration constraints will also support prioritisation of future trials in the system security transition pathway.

Within the next two-year period, AEMO is expecting to enter into up to 10 Type 2 transitional services, including at least one per Statement of Need already published and an additional two to three agreements related to proposed services or priority focus areas. AEMO will only enter into such agreements where it is considered prudent and efficient considering the procurement objectives of maintaining power system security, achieving emissions reductions targets, and minimising costs to end users.

2.4 Policy reform to support the evolution of the power system security

Throughout 2025, market bodies and governments have been investigating what further policy and regulatory measures are necessary to support the timely and cost-efficient delivery of resources with essential system service capabilities.

2.4.1 Reforms to the National Electricity Rules

In November 2025, AEMO submitted a rule change request[52] to the AEMC to amend the NER planning and procurement frameworks for system strength and inertia to support the efficient and timely deployment of resources required to meet system security needs over the energy transition. AEMO notes that while significant work has been done to date on establishing the planning frameworks – including completion of the first system strength Regulatory Investment Tests for Transmission (RIT-Ts) – they are still evolving and in the early stages of implementation.

The rule change seeks to address the issues and challenges observed to date with the planning frameworks which, in their current form, do not currently provide sufficient time or the flexibility needed in planning timeframes to respond to the range of variables arising that can materially alter system operating conditions and the resources available to AEMO to keep the system secure. It does this by focusing on options to evolve the frameworks and address these issues so they are better positioned and ready for the next planning cycle and can deliver outcomes that are in the long-term interests of consumers.

There is an asymmetry of risk between over- and under-procurement, and early and late delivery of resources to provide system strength and inertia services. While over-procurement carries the possibility of consumers bearing additional costs, the risks and costs of under or late procurement are likely to be much higher. Procuring ahead of time helps protect against delivery schedule delays, and high impact low probability events with severe consequences such as unserved load and system black outs. Inadequate resources for system strength can also lead to higher wholesale market costs and emissions and create uncertain conditions for new investment, resulting in worse outcomes for consumers (see box in Section 1.2.4).

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[52] See https://www.aemc.gov.au/rule-changes/security-framework-enhancements.

Poorly coordinated investment in new resources can also lead to duplicate and inefficient investments (e.g. building a firming gas plant in one location and a separate synchronous condenser at the system strength node close by), resulting in additional delays and costs for consumers. This investment coordination challenge is created by the physical unbundling of services in a mainly inverter-based system and may require more substantive changes to the regulatory frameworks to better enable market led investment.

AEMO's rule change presents an opportunity to work with the AEMC and industry to enhance the existing frameworks through enabling system strength and inertia shortfalls to be declared and managed more effectively, improving planning certainty and incentives for non-network and network solutions, and better aligning the planning framework timeframes for system security resource entry and exit. Enhancements like these can help ensure the frameworks facilitate the timely and efficient investment in system security capabilities so that they:

- enable AEMO to operate the power system and markets efficiently, reliability and securely as they transition to a predominately renewable energy-based system, and
- deliver outcomes in both the investment and operational timeframes that are in the long-term interest of consumers.

2.4.2 Policy support for system security

Policy settings will be essential to address challenges associated with constraints on upstream supply chains and coordinating investment in assets that can provide multiple system services. AEMO is engaging in a range of government-led initiatives that are investigating how existing and new policies and market reforms can support the timely delivery of resources with system service capabilities.

At its August 2025 Energy and Climate Change Ministerial Council meeting, Ministers agreed to an action plan to support system security across a range of priority areas including regulatory frameworks, policy, and technological innovation[53]. In parallel, the ongoing NEM Wholesale Market Settings Review, led by a government-appointed Expert Panel, is also considering how the proposed Electricity Services Energy Mechanism can procure system services through the project development stage to capture opportunities for cost effective incremental investment in system service capabilities[54]. AEMO supports these processes and will continue to engage in them to help identify and inform government on policy settings and reforms that support the timely and cost-efficient delivery of system service resources.

The policy work underway across the National CER Roadmap reinforces this direction, with a strong national push to modernise system-security frameworks for a high-CER system. As discussed in Part C Section 9.2, the *Redefining roles* workstream highlights how secure operation increasingly relies DNSPs establishing Distribution System Operator (DSO), coordination between transmission and distribution system operation and control hierarchies for DER both normal and abnormal system conditions. CER Roadmap workstreams also highlight the increasing importance of customer agents and other emerging actors and the need for defined responsibilities for device behaviour, data handling and compliance, given their growing influence in the power system.

In parallel, the *Integrating Price Responsive Resources* (IPRR) reform will enable aggregated flexible demand and small storage to be visible and dispatchable through structured dispatch modes and operational data requirements. This greatly enhances AEMO's ability to see and manage price-responsive CER, reducing uncertainty around CER behaviour at times and allowing it to be better harnessed as a source of flexibility for managing system security.

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[53] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/meetings-and-communiques.

[54] At https://assets.pc.gov.au/2025-09/wholesale-electricity-post-draft.pdf; see recommendation 8B.

2.4.3 Connections reform

AEMO is enabling faster, more efficient connections through a suite of targeted initiatives.

The Connections Reform Initiative (CRI)[55] has introduced an optional pre-application milestone, early OEM model assessments, and a streamlined commissioning guideline and toolkit to facilitate early collaboration, reduce rework and enable generators to reach full output sooner, while maintaining system security.

Government programs like the Summer Readiness Program have already accelerated over 3 gigawatts (GW) of projects ahead of peak demand, while the Streamlined Connections Pilot Program and Accelerated Connections Fund are testing reforms to reduce application to registration timeframes. The New South Wales Accelerating Battery Projects Program provides dedicated support to accelerate large storage projects in the region and reduces duplication of work across stakeholders.

In parallel, AEMO is optimising its digital platforms, including the development of the Connection Web Application, Registration Portal, and Solutions Register, to simplify submissions, improve transparency and create a secure data transfer repository.

Technical enhancements include the Frequency Scanning Proof of Concept Report and a comprehensive review of Access Standards to further define the technical requirements for connecting generation, storage, and large loads.

Collectively, these initiatives aim to deliver a consistent, predictable, and collaborative process that accelerates the energy transition.

2.5 Feedback on the 2024 Transition Plan for System Security

Although formal consultation is not required as part of the release of the *Transmission Plan for System Security*, AEMO values input from a wide variety of stakeholders to inform its thinking as part of an ongoing commitment to engage, listen and understand stakeholder perspectives. To facilitate this, AEMO called for broad input on the 2024 *Transition Plan for System Security* between December 2024 and March 2025, with written feedback received from eight stakeholders across generators, retailers, developers and peak bodies.

In addition to this engagement and feedback, AEMO met with the AEMC Reliability Panel several times and the Reliability Panel provided a formal submission as required under the NER.

This section highlights the material feedback from the Reliability Panel and feedback from other stakeholders, along with AEMO's response. As this was not a formal consultation, and AEMO did not advise that submissions would be made public, the wider stakeholder feedback received has been de-identified.

Feedback concentrated on the case for urgent action from many parties, and the importance of a clear and transparent plan, as summarised in **0**.

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[55] See https://www.aemo.com.au/initiatives/major-programs/connections-reform-initiative.

Table 9 Summary of stakeholder feedback and AEMO responses

	Stakeholder feedback	AEMO responses in 2025 *Transition Plan for System Security*
The case for urgent action from many parties		
Asymmetric risks	The Reliability Panel emphasised "*the urgency of system security investment to keep pace with the transition"* due to long and uncertain lead times of investments and project delivery. The Panel highlighted that the foundational importance of system security creates a highly asymmetric risk profile for *"over- and under-investment".*	AEMO agrees that system security shortages pose an asymmetric risk, and recognises the potential for both over- and under-investment and the complexity of striking the right balance between appropriate investment and risk mitigation (see box in Section 1.2.4). AEMO's view is that it is in the long-term interest of consumers to take proactive, anticipatory actions to de-risk potential security and reliability impacts, provided the costs are not prohibitive. This report highlights and explains some of the potential asymmetric risks and actions to mitigate these, including through urgent investment.
	A market participant highlighted the speed and uncertainty of major coal retirements. Similarly, a peak body highlighted the asymmetric risk of "*moving pre-emptively to resolve these issues versus moving too late*". A generator was concerned about an overemphasis on scenario planning "*risks undermining system security*" if assumptions about new technologies or market changes do not materialise as expected.	
Trade-off between timeliness and accuracy	The Reliability Panel noted that, while "there is a trade-off between timeliness and accuracy when identifying specific security needs" a priority should be given to identification and action "as far ahead into the transition as practicable" "so that timely investment can occur" to mitigate the significant and asymmetric risks.	AEMO agrees with these arguments and priorities. AEMO manages the uncertainty of the future – in terms of network configuration, generation output, technology capabilities, and customer behaviour, amongst others – across many activities. Section 2.2.3 details how this is managed in assessing system security. Part B of the report identifies and assesses transition points across a ten-year horizon, which is the limit that AEMO believes is practicable. Furthermore, AEMO is planning for 2024 ISP *Step Change* scenario in these security assessments by considering scenarios for coal plant decommitment ahead of coal plant retirement (with credible occurrences of no coal online as early as 2031-32 in New South Wales and 2033-34 in Victoria). While these scenarios contain significant uncertainties, AEMO believes they are valuable reference points for what is needed to securely manage an accelerating transition, and thereby inform urgent preparatory actions.
Consequences of inaction	The Reliability Panel requested AEMO publish "the actions AEMO will take, and the consequences, if investment or capability cannot be delivered on time".	To address this feedback, AEMO has outlined the operational tools AEMO may use to maintain security and the consequences of insecure operation in Section 1.3.1 and Section 1.2.3. Furthermore, this report details the potential consequences, if investment or capability cannot be delivered on time and in full, for relevant transition points in Part B.
	A peak body advised that AEMO should provide a reasonable expectation of the "last time to reasonably act", and "the impact of the closure of each prospective coal-fired generator well ahead of its scheduled closure." Similarly, a renewable generator suggested the report should take into account the "last time to act" based on investment lead times.	

	Stakeholder feedback	AEMO responses in 2025 *Transition Plan for System Security*
Actions from others are needed	The Reliability Panel "considers that the TPSS should identify areas where AEMO cannot address a security issue, and where actions from others are needed".	AEMO agrees that many stakeholders share the roles and responsibilities for system security in the NEM, as summarised in Section 2.1. The parties responsible for actions are furthermore noted for each transition point in Part B. AEMO's policy engagements (Section 3.4) emphasise the opportunities to leverage broader energy policy and capitalise on opportunities to have assets provide both energy and security services. Leveraging broader energy policy includes utilising existing or anticipated government energy schemes and/or direct investments to build support for power system security. Co-optimised investments in assets that could deliver multiple and varied energy and system security services will likely result in cost efficiencies for consumers over the longer term, as well as building in resilience. For example, this could include one asset providing multiple system security services – e.g., a synchronous condenser with a flywheel can support system strength and inertia – or one asset supporting both system security and reliability/firming – e.g., a gas-fired asset with a clutch and black-start capability can support peak demand, minimum fault levels, voltage waveform stability , provide backup for renewable droughts, and support system restoration.
Future-focused, including planning for coal decommitment		
A future-focused, detailed, and consolidated plan	The Reliability Panel suggested AEMO "reconsider the current 'horizons' approach and extend its detailed recommendations into the planning timeframe, to support timely investment". Extending on this theme, the Panel suggested the "TPSS identify the post-transition state of the power system and the resulting security needs". Coal decommitment and retirement was another prominent theme in feedback. The Reliability Panel requested "detailed plan[s] to manage coal plant retirements" including the "actions, investments in resources, or services needed to meet each system security need". The Panel also requested AEMO specify the "last time to act".	AEMO has responded by extending the Horizon 2 analysis from 2-to-5-years (in 2024) to 2-to-10-years. This covers the most challenging period for security in most region's transitions, including analysis of operating NSW and Victoria with zero coal units online. Coal decommitment – including more flexible operation – and retirement is a major focus of this year's report. There are eight transition points representing such coal decommitments, each of which includes discussion of the required preparatory actions to manage these changes and the operational consequences if preparatory actions are not completed ahead of time. While the high levels of uncertainty surrounding the energy transition make it difficult to specify a 'last time to act', AEMO is taking a prudent, risk-aware approach (described above) to inform stakeholders as early as possible/practical.
	Similarly, a peak body suggested the TPSS align with their members' planning and investment timeframes of two years to six years. A generator advised that each 'horizon' should be reported "against the attributes listed in AEMO's Power System Requirements report, linking the capability needed to the operational metrics". A peak body emphasised the importance of preparing for "the closure of each prospective coal-fired generator well ahead of its scheduled closure", while a generator seeks information on "specific actions AEMO is taking in Horizon 3 to manage power system security without coal generation" and a focus on long-term solutions.	
Increased detail	In addition to detailed plans for coal decommitment, market participants wish to better "understand how AEMO is utilising the new Transitional Services framework" and requested "investable recommendations". One market participant was concerned that the report lacked "critical technical details necessary for informed market investment and system security	AEMO made first use of the Transitional Services framework in December 2024, after publication of the 2024 TPSS. AEMO has since published 13 Statements of Need for Transitional Services described in Section 3.3. AEMO believes security investments are urgently needed, and as such this report provides specific information as far into the planning horizon as feasible. However, ultimate decisions on specific investments are the responsibility of TNSPs and market participants (see Section 2.1) and may be incentivised by governments.

	Stakeholder feedback	AEMO responses in 2025 *Transition Plan for System Security*
	decisions", and request clearer and more specific actions, rather than broad studies. A renewable generator said plans need to be "specific and actionable, based on detailed engineering studies". Similarly, another market participant seeks "details of any active or planned trials". One developer highlights the need for more granular information including changes in the estimated levels of minimum demand required to maintain system security, and more 'granular analysis to enable region-based transition point planning'.	AEMO has increased the detail in the 2025 report, particularly in the regional plans of Part B, as well as in the discussion of AEMO's operational toolkit (see Section 1.3.1) and modelling and transition planning activities (see Section 2.2.3). Appendix A3 contains detailed forecasts of minimum demand conditions in each NEM region.
Consolidate reporting	The Reliability Panel recommended that, in the interest of effective communication that "is understood and acted upon", "AEMO consolidate its system security publications".	AEMO agrees with this approach and has combined its NSCAS, system strength, inertia and TPSS reporting into the 2025 TPSS.
	Similar feedback was received from other stakeholders, including governments.	

2.6 Forward stakeholder engagement plan

Coordinated and collaborative engagement across the entire energy sector is vital to deliver an effective, efficient, and timely *Transition Plan for System Security*. Through this report, AEMO identifies that:

- there are several areas requiring targeted action from TNSPs and DNSPs to support system security, and
- the resourcing and efforts required to trial and prove new technologies, assess quantities and locational requirements, and progress through upcoming transition milestones are new, different, and in addition to current activities.

In addition to seeking input and consulting on elements of the *Transition Plan for System Security*, AEMO undertakes extensive engagement across many other aspects of its work – both in the NEM and WEM. This includes through existing formal mechanisms such as the Executive Joint Planning Committee (EJPC) and Joint Planning Committee (JPC), a dedicated DNSP Executive Forum, a range of technical working groups on operational matters, and regular discussions with market participants, governments, industry associations and consumer advocates.

To help facilitate further collaboration across the industry, AEMO is considering how it can engage more deeply on technical challenges and opportunities, either through existing committees and forums or via establishment of new channels, and would welcome feedback from stakeholders on how best to engage on these technical matters.

AEMO also recognises increasing interactions between CER and power system security management frameworks and continues to build stakeholder engagement to support this. AEMO seeks feedback from any interested stakeholders on the following points to inform development of subsequent Transition Plans, particularly on the questions in the box below.

Questions

1. What was most useful in this year's *Transition Plan for System Security* that would be useful in future?
2. What additional information would help stakeholder decision-making on investments that support system security?
3. Where is additional effort required to maintain system security while transitioning to higher contributions of renewables?
4. How best should Engineering Roadmap content be merged and balanced with the system security information in the next *Transition Plan for System Security*?
5. Do you have any feedback on how AEMO can/should continue to engage on technical matters?

Interested stakeholders are encouraged to submit responses to futureenergy@aemo.com.au by 2 February 2026. AEMO will publish responses, so please identify any information that you wish to remain confidential. For further information, please view AEMO's submission guidelines[56].

There will be further opportunities to engage with AEMO and inform the content and approach of the *Transition Plan for System Security*. Interested parties are encouraged to contact futureenergy@aemo.com.au to register for updates.

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[56] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/working_groups/industry_meeting_schedule/aemo-consultation-submission-guidelines.pdf.

Part B. Regional transition plans

Part B. Regional plans for maintaining security through the transition to a low- or zero-emissions power system

Structure

Part B identifies and assesses industry readiness for specific transition points (events that require material changes in the operational approach to managing system security) in each NEM region.

It presents publicly available data on infrastructure developments and in-flight actions in the region and how these align with transition points. The timing of coal transition points is set to the earlier of public announcements and 2024 ISP Step Change scenario, which projects many coal plant to decommit earlier than their current public announced closure dates. As described in Part A, this is done as a prudent response to the asymmetric risk profile of system security.

Each region contains:

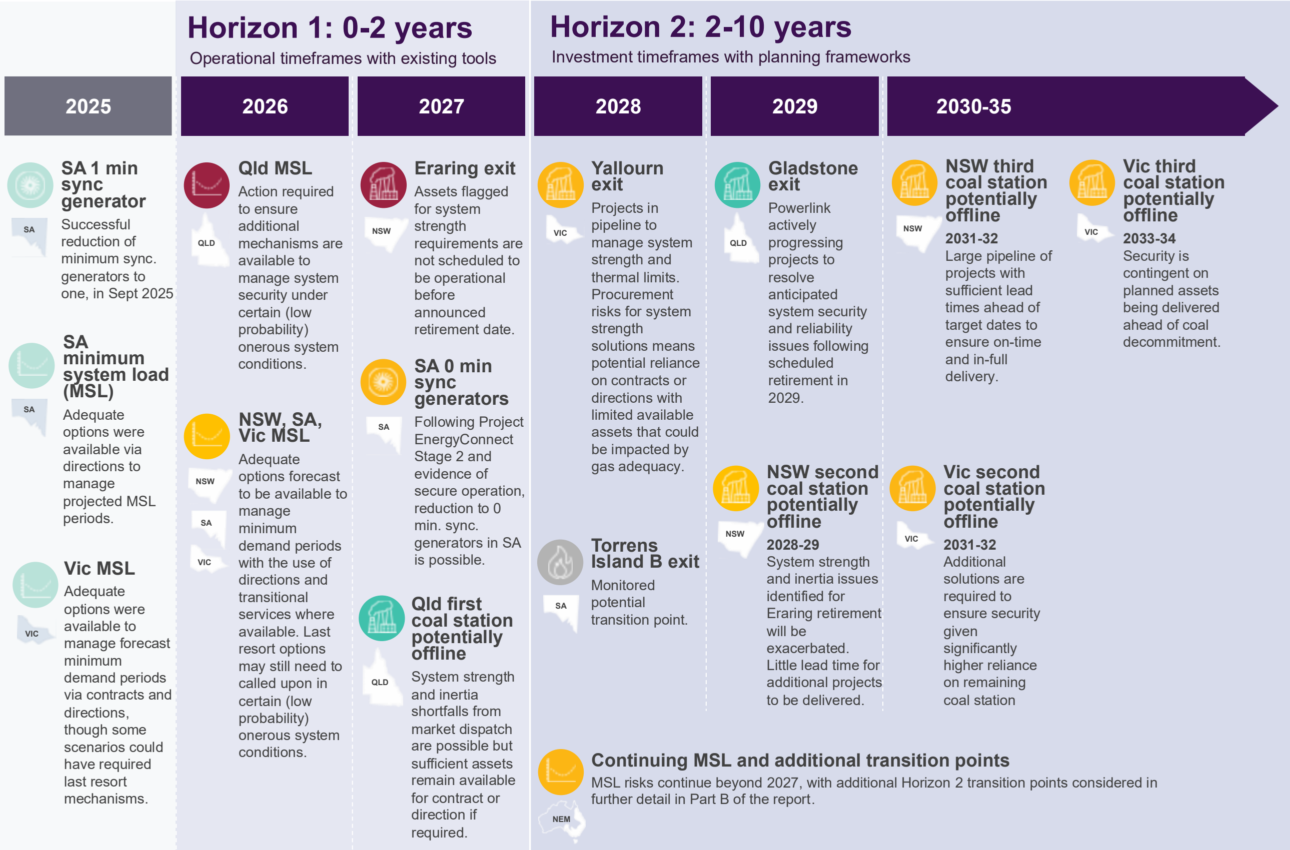
- an overview page, including operational metrics that give a snapshot of current conditions,
- a summary of analysis assumptions and NSCAS findings,
- detailed readiness assessments for each identified transition point

Transition point readiness assessments

The readiness of transition points is assessed using the system criteria described in Part A. The overall risk profile is summarised in an 'on track', 'moderate readiness', 'unresolved issues' rating. Much of this analysis is based on AEMO's system security planning studies.

Many transition points have moderate readiness levels (and two are unresolved issues), indicating that more urgent actions are required by the many stakeholders who share responsibility for security. While it may appear that there is less urgency to act on more distant transition points, the long lead times of regulatory approvals, investment decision making, global supply chains and project delivery means the 'last time to act' for these transition points is often imminent.

Part B is complemented by in-depth discussion of system-wide developments and plans, such as system restart and Minimum System Load (MSL), in Part C, with supporting information in Appendix 3.



Horizon 1: 0-2 years

Operational timeframes with existing tools

Horizon 2: 2-10 years

Investment timeframes with planning frameworks

2025

SA 1 min sync generator
SA
Successful reduction of minimum sync. generators to one, in Sept 2025

SA minimum system load (MSL)
SA
Adequate options were available via directions to manage projected MSL periods.

Vic MSL
VIC
Adequate options were available to manage forecast minimum demand periods via contracts and directions, though some scenarios could have required last resort mechanisms.

2026

Qld MSL
QLD
Action required to ensure additional mechanisms are available to manage system security under certain (low probability) onerous system conditions.

NSW, SA, Vic MSL
NSW SA VIC
Adequate options forecast to be available to manage minimum demand periods with the use of directions and transitional services where available. Last resort options may still need to called upon in certain (low probability) onerous system conditions.

2027

Eraring exit
NSW
Assets flagged for system strength requirements are not scheduled to be operational before announced retirement date.

SA 0 min sync generators
SA
Following Project EnergyConnect Stage 2 and evidence of secure operation, reduction to 0 min. sync. generators in SA is possible.

Qld first coal station potentially offline
QLD
System strength and inertia shortfalls from market dispatch are possible but sufficient assets remain available for contract or direction if required.

2028

Yallourn exit
VIC
Projects in pipeline to manage system strength and thermal limits. Procurement risks for system strength solutions means potential reliance on contracts or directions with limited available assets that could be impacted by gas adequacy.

Torrens Island B exit
SA
Monitored potential transition point.

2029

Gladstone exit
QLD
Powerlink actively progressing projects to resolve anticipated system security and reliability issues following scheduled retirement in 2029.

NSW second coal station potentially offline
NSW
2028-29
System strength and inertia issues identified for Eraring retirement will be exacerbated. Little lead time for additional projects to be delivered.

2030-35

NSW third coal station potentially offline
NSW
2031-32
Large pipeline of projects with sufficient lead times ahead of target dates to ensure on-time and in-full delivery.

Vic third coal station potentially offline
VIC
2033-34
Security is contingent on planned assets being delivered ahead of coal decommitment.

Vic second coal station potentially offline
VIC
2031-32
Additional solutions are required to ensure security given significantly higher reliance on remaining coal station

Continuing MSL and additional transition points
NEM
MSL risks continue beyond 2027, with additional Horizon 2 transition points considered in further detail in Part B of the report.

Transition points are events that require material changes in the operational approach to managing system security. These utilise 2024 ISP Step Change projections, noting coal exit order is influenced by commercial drivers and asset condition. Additional points will be considered as required in future plans.

Industry readiness for transition point
● Complete/ on track
● Moderate readiness
● Unresolved issues

New South Wales

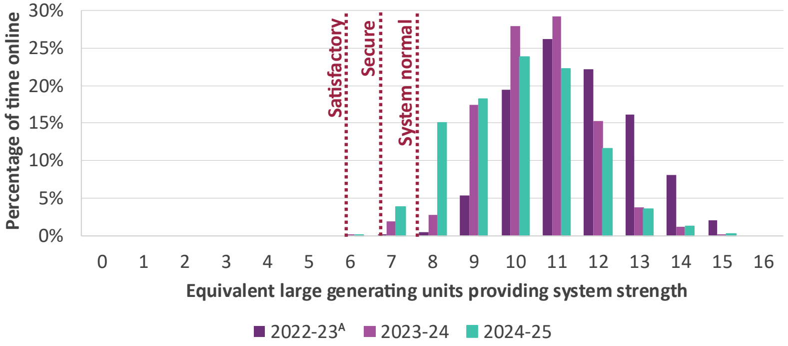
Context

System security in New South Wales is currently heavily reliant on large synchronous generators. Many coal generators are approaching end of life, and some are exploring options for operational flexibility that could include two-shifting and potential seasonal lay-ups. Eraring announced exit is currently August 2027 and Bayswater has commented publicly on its two-shifting trials. In October 2025, AEMO has observed an increase in directions issued to maintain system strength in New South Wales.

Identified transition points in New South Wales are closely linked to decommitment of coal generation, which is projected to occur due to market pressures far in advance of announced exit dates. Minimum system load (MSL) conditions are another transition point, with MSL2 conditions[B] forecast to occur in system normal from Spring 2026.

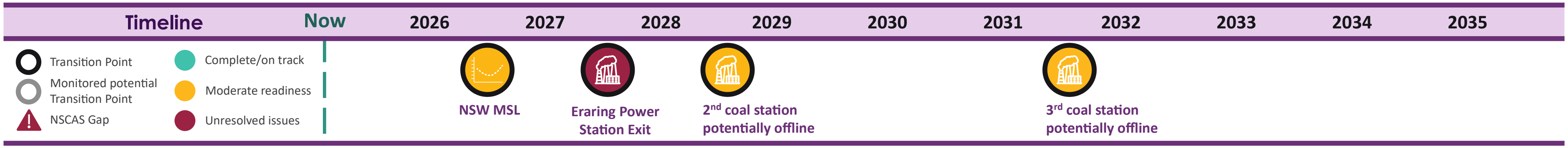
The New South Wales government is supporting the creation of five renewable energy zones, incorporating new generation, transmission, and synchronous condensers. The government has also aligned its Long Duration Storage target for 2035 with the closure of two of the states' remaining coal-fired power stations.

Maintaining system strength above security limits is increasingly challenging



Eraring Power Station exit removes 4 equivalent units of system strength

Network augmentation and synchronous condensers will reduce limits



Security challenges

The system strength requirements to enable the planned retirement of Eraring Power Station have been identified by AEMO each year since 2021. Transgrid is progressing the procurement of new synchronous condensers, with delivery scheduled to begin in 2028.

Prior to synchronous condensers being operational, AEMO may need to enable Transgrid system strength contracts or issue directions to bring synchronous generation online. Risks of needing to de-energise assets and shed load may also arise if there are insufficient synchronous generators available to direct, particularly under outage conditions as currently planned for Spring 2027. Further decommitment of coal generation shortly after Eraring's retirement could exacerbate these existing issues.

NSW's minimum operational demand is projected to decline by 300 MW per year over the next 5 years. For typical system normal conditions, if decommitments and investments in storage proceed on time and there is enhanced flexibility of CER to manage output in the middle of the day, the incidences in which DNSPs will need to enact mechanisms (such as emergency backstop) will remain rare.

Actions

As early as 2031-32, New South Wales could at times reach a "credible no coal scenario" where a combination of exits, decommitments, planned outages and contingencies means there are periods with no coal generation available for dispatch or directions.

Industry need to prepare to operate the power system in such conditions. Prudent preparation includes delivering all committed, anticipated, and actionable projects in the current pipeline, and all government-supported generation, firming, and long-duration storage targets, on time and in full. This includes:

- **Transgrid** to deliver the portfolio of system strength solutions identified in its RIT-T, including the first tranche of synchronous condensers from the preferred portfolio option, contracting to manage operational risks, and actionable Sydney ring transmission projects.
- **EnergyCo**, **ACEREZ** and **New South Wales Government** to deliver synchronous condensers and transmission to support REZ developments.

A. Assumes Liddell units contribute 0.73 Major Units

B. In MSL2 conditions the power system is one credible load contingency away from requiring immediate action from AEMO and DNSPs to increase demand.

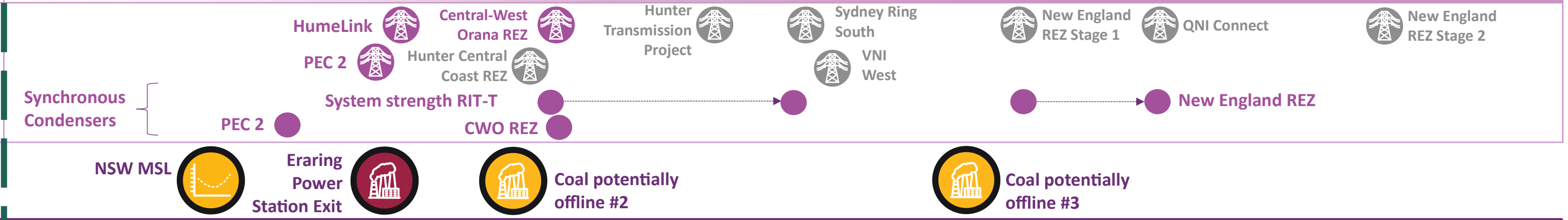
New South Wales

REGIONAL DEVELOPMENTS	Now	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Synchronous generator capacity change *Annual capacity changes (MW)*		+750		-2,940	+1,100				-40	-4,035	
Committed and anticipated IBR *Annual capacity changes (MW)*		+3,804	+550	+2,367	+1,970	+919	*Future project details periodically evaluated in NEM generation information processes*				
IBR forecasts (*Sets efficient Sys. Strength level)* *Annual capacity changes (MW)*		+3,804	+550	+6,888	+8,276	+9,057	+2,297	+863	+4,113	+1,304	+3,984

Transmission augmentation[A, B]

● Committed/anticipated

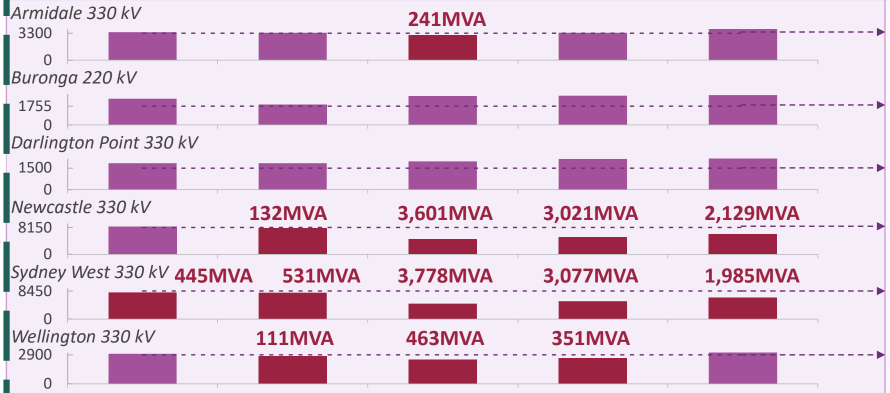
● RIT-T in progress/actionable



Transition Points

AEMO'S CURRENT OUTLOOK	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Assessment horizon	***NSCAS assessment** (See Appendix 2)*					***Long term assessment***				

System strength – *nodal assessment*
(minimum fault current in MVA)

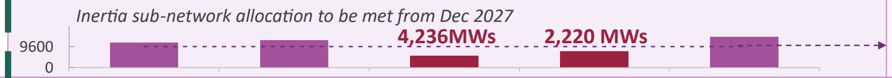


Long-term, system strength requirements are managed by Transgrid through the RIT-T framework.

Transgrid's RIT-T is currently at the Project Assessment Conclusions Report phase, published in July 2025, and initial stages of procurement are underway. The New South Wales government has enabled acceleration of the first tranche of synchronous condensers from the preferred portfolio option, making portfolio 4 in the RIT-T now credible.

This portfolio option features the delivery of synchronous condensers in two tranches, and contracts with synchronous machines to manage system strength in the interim. System strength is expected to be further addressed by delivery of REZ synchronous condensers.

Inertia (MWs)



Low long-term risk due to Transgrid flywheel-equipped RIT-T synchronous condensers and IBR participation in frequency market, providing sufficient inertia and frequency support respectively.

Thermal and voltage

No gaps declared, however emerging voltage/thermal risks are forecast with current pipeline of committed and anticipated projects. Delivery of actionable projects needed to address risk.

------ Requirements ▨ Available level ▨ Deficit ⚠ NSCAS Gap

A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

B. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

Minimum System Load – New South Wales

5-year outlook

New South Wales ● Moderate readiness

Assessed

System strength

Frequency and inertia

Voltage control

Operability

Resource adequacy

To be assessed

System restoration

Transient and oscillatory stability

Context

New South Wales experienced a record minimum 30-minute operational demand of 2,718 MW (16 February 2025 12:30), this contrasts with a maximum demand of 14,744 MW (1 February 2011). The 2025 ESOO anticipates operational demand will continue to fall by 300 MW a year. New South Wales is currently progressing the development of emergency backstop, with plans for implementation from Q2 2026. As operational demand continues to decline in New South Wales and neighbouring regions, there is a growing risk of coincident events, resulting in increased challenges.

Impacts

As minimum system load (MSL) continues to decline, technical challenges emerge. AEMO determines MSL thresholds according to the level of demand needed to operate the minimum combination of synchronous generating units required to maintain security[A]. Under plausible onerous conditions, demand in New South Wales needs to be maintained at or above 2,240 MW (reducing to 2,099 MW with new utility-scale BESS in spring 2026) to ensure provision of essential system services.

If MSL2 or MSL3 conditions are forecast, AEMO takes actions to clear the condition. Current AEMO actions include recalling network outages or decommitting synchronous units.

If MSL3 conditions persist following AEMO actions, or MSL3 is forecast without sufficient lead time for AEMO actions to take effect and clear the condition, AEMO instructs Network Service Providers (NSPs) to maintain operational demand above the required threshold to maintain system security. At present, New South Wales Distribution NSPs' (DNSPs') capabilities to increase operational demand include:

- Curtailing embedded generators including non-scheduled PV (PVNSG)
- Load shifting via batteries
- (Under development, planned to begin Q2 2026) Active CER management via Common Smart Inverter Protocol – Australia (CSIP-AUS)
- Emergency voltage management (EVM), the deliberate increase of distribution voltages to disconnect distributed PV [B].

MSL Outlook *Refer to TPSS Part C and Appendix 3*[C]

Under typical system normal conditions: if coal generation exits and network investments proposed across the NEM proceed as planned, no forecast MSL3 conditions are projected in New South Wales, and all forecast MSL1 and MSL2 events over the outlook horizon are projected to be resolvable via AEMO actions and export into other regions. Any delays in planned transition activities (particularly Transgrid RIT-T synchronous condensers) may increase the number of events requiring operational management, this may occur as early as 2027-28; coordination of large-scale storage and CER may help to decrease the need for intervention in the outlook period.

Rare, but plausible, onerous system conditions are modelled assuming 1) typical large synchronous units operating at minimum levels, 2) export from the region not possible, and 3) Shoalhaven and Tumut 3 pumping loads unavailable. The modelling also considers an additional 2.6GW/7.1GWh of utility-scale BESS.
Under such rare onerous system conditions: if planned actions proceed (including introduction of active CER management as scheduled), it is projected that available operational demand increase services will be close to sufficient. In the absence of further actions (see below), if such onerous conditions were to occur in Spring 2026 and coincide with very low demand periods, it may be necessary for DNSPs to enact almost all mechanisms, including curtailment of embedded generation and use of EVM.

Actions

The development of activities to ensure a smooth transition and provision of essential services in New South Wales is underway. Recommended actions include:

- **New South Wales Governments** and **NSPs** to progress and consider additional innovative capabilities to expand MSL3 actions available to increase operational demand under plausible onerous system conditions by 2026-27 to avoid reliance on reverse feeder shedding.
- **NEM NSPs** and **industry** to target delivery, on time and in full, of planned investments of system security solutions and pathways to lower generator minimum operating levels to reduce the likelihood of future MSL3 events.
- **Industry** and **government** to consider further incentives for coordination of storage and CER, particularly to support low demand periods.
- **AEMO** is seeking expressions of interest to supply either Type 1 Transitional Services to address immediate MSL conditions or Type 2 Trial Services for novel solutions beyond 2028. Interested parties to consider opportunities to deliver these services for MSL[D].

A. This includes: MSL3: immediate action needed to increase demand; MSL2: system is one credible load contingency away from MSL3; and MSL1: system is two credible load contingencies away from MSL3. Further details on the strategies for managing MSL into the future can be found in Section 9.

C. Refer to Part C Section 9.2 and Appendix A3 for further details.

B. In relation to EVM, DNSPs need to assess risks, consider pathways (including relevant regulations and legislation), conduct modelling, testing and/or trials as necessary to confirm whether this option is suitable for their network, while ensuring safety and low risk to customer equipment.

D. For more information, visit https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning

Minimum System Load – New South Wales

5-year outlook

New South Wales

● Moderate readiness

Assessed

System strength

Frequency and inertia

Voltage control

Operability

Resource adequacy

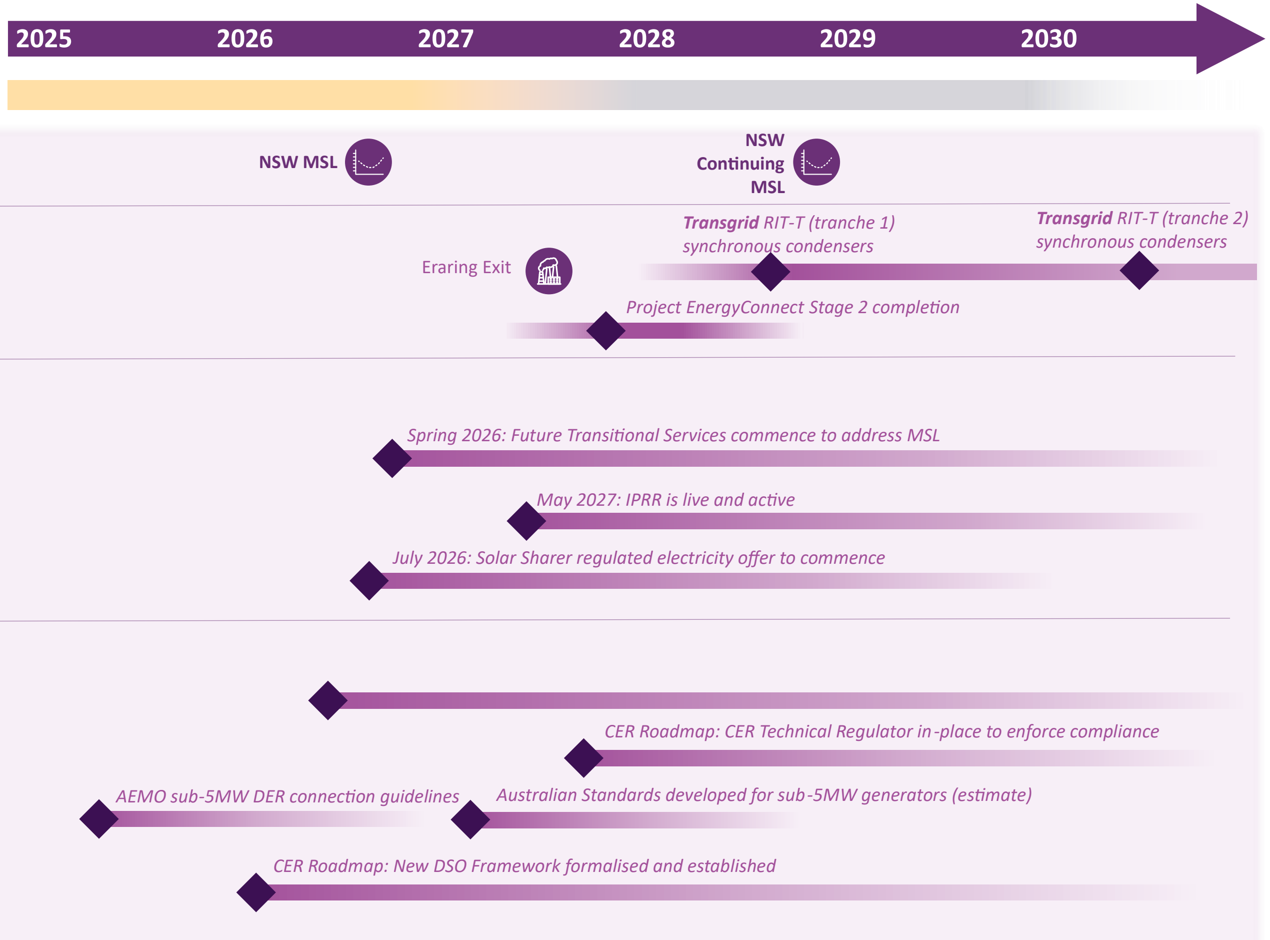
To be assessed

System restoration

Transient and oscillatory stability

◆ *Target date* ▬ *Expected start/end date*

Readiness to maintain system security during onerous MSL conditions[A]



Transition points

Reduce synchronous generation needed to remain online

Transgrid delivering network investment to reduce minimum synchronous generator unit commitment required in New South Wales

Transgrid and **Electranet** delivering network investment to increase export (Completion of EnergyConnect Stage 2)

Soak up excess generation with demand or storage

AEMO, market participants and **interested parties** to develop long-term MSL strategies through Type 1 service procurement and Type 2 trial services

Market participants progressing the integration of aggregated CER for market participation to mitigate MSL periods

Federal Government exploring retail energy offer to incentivise daytime operational demand increase

Managing DPV generation

New South Wales Gov, DNSPs and **OEMs** implementing Emergency Backstop requirements, introducing means to measure and enforce compliance, with consideration for flexible export capabilities

Industry improving compliance with emergency backstop

New South Wales DNSPs and **AEMO** standardising technical performance and processes, and developing monitoring and active management of embedded generation

Government and **market bodies** evolving roles and responsibilities for DSOs in managing MSL and conformance frameworks for operational compliance

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A. Beyond 2027-28, there is a high level of uncertainty in the forecast of both MSL thresholds and capabilities of MSL actions available to NSPs

Eraring exit

Q3 2027

New South Wales

● Unresolved issues

◆ Action required

Assessed

- System strength ◆
- Frequency and inertia ◆
- Voltage control
- System restoration
- Operability ◆
- Resource adequacy ◆

To be assessed

- Transient and oscillatory stability

Context

The closure of Eraring Power Station will result in four coal generating units with a total generation capacity of 2,880 MW being withdrawn from the New South Wales power system. System strength requirements to enable the planned retirement of Eraring Power Station in August 2027 have been identified by AEMO each year since 2021, and **Transgrid** is progressing the procurement of new synchronous condensers. However, these assets are not currently scheduled to be operational until 2028, even though currently being fast -tracked.

Impact

The exit of Eraring Power Station before these synchronous generations are operational would negatively impact system strength and inertia in New South Wales. Minimum generator requirements for system strength may require AEMO to activate **Transgrid** system strength contracts (where available) or operationally intervene in the market up to 30% of the time.

In the event of a credible contingency, gas generation may need to be brought online to meet system strength and reliability requirements. Some gas generation may be unavailable due to gas supply constraints and limited run time. Backup diesel supplies at some gas facilities may provide short-term support. If sufficient coal, gas or hydro generation is not available, such as during outages or coal generators two-shifting, **AEMO** may need to direct the de-energisation of sections of the transmission network, resulting in localised loss of supply to customers.

Actions

- **Transgrid**, with the support of the **New South Wales government,** is fast tracking investment in the first tranche of synchronous condensers to meet system strength requirements[B,C]. However, these are not expected to be operational until at least 2028, and are subject to supply chain constraints, project delays, and other risks. **Transgrid** is seeking to procure system security contracts to fill gaps between exit of Eraring and arrival of synchronous condensers[B]. Currently one provider is expected, however **Transgrid**'s RIT-T identified more contracts would be required.
- **AEMO** will communicate with generators where planned outages could impact system security so operators can consider changes to outage schedules.
- If currently scheduled outages in Spring 2027 do not change, **AEMO** will likely need to activate Transgrid's system security contracts and direct one or more generators to shift scheduled outages, or direct others to operate at minimum load or as synchronous condensers (based on their capabilities) to provide system strength. Based on the current outage schedules, risks of needing to de-energise assets and shed load arise during this time.
- **AEMO** will also ensure all operational procedures, processes, and constraints are updated to account for changes in system conditions. As a precautionary measure, **AEMO** will work with **Transgrid** to prepare a procedure on which sections of the transmission network may be de-energised and consult with the New South Wales Jurisdictional System Security Coordinator (JSSC).
- **AEMO** is completing preparatory work to facilitate small signal stability analysis that incorporates system changes associated with the exit of Eraring and other synchronous generators. This aims to ensure that stabilising devices effectively damp inter -area modes. This work is expected to be well progressed in 2026.

Transgrid to complete transmission projects[A]

Transgrid's synchronous condensers for system strength operational[B]

ACEREZ to complete Central-West Orana REZ network infrastructure project including synchronous condensers[B,D]

EnergyCo / Ausgrid to complete Hunter Central Coast REZ network infrastructure project, including system strength solutions[E]

ASL running Firming Tender (0.5 GW)[F] following New South Wales Minister's direction

Market delivers new firming and dispatchable generation

AEMO enables **Transgrid** system security contracts or issues directions for system strength

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A. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

B. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

C. See https://gazette.nsw.gov.au/gazette/2025/9/2025-9_376-gazette.pdf

D. See https://www.acerez.com.au/the-project

E. See https://www.energyco.nsw.gov.au/our-projects/hunter-central-coast-rez

F. See https://asl.org.au/tenders/tender-round-7-firming-infrastructure

Eraring exit

System strength – minimum fault level

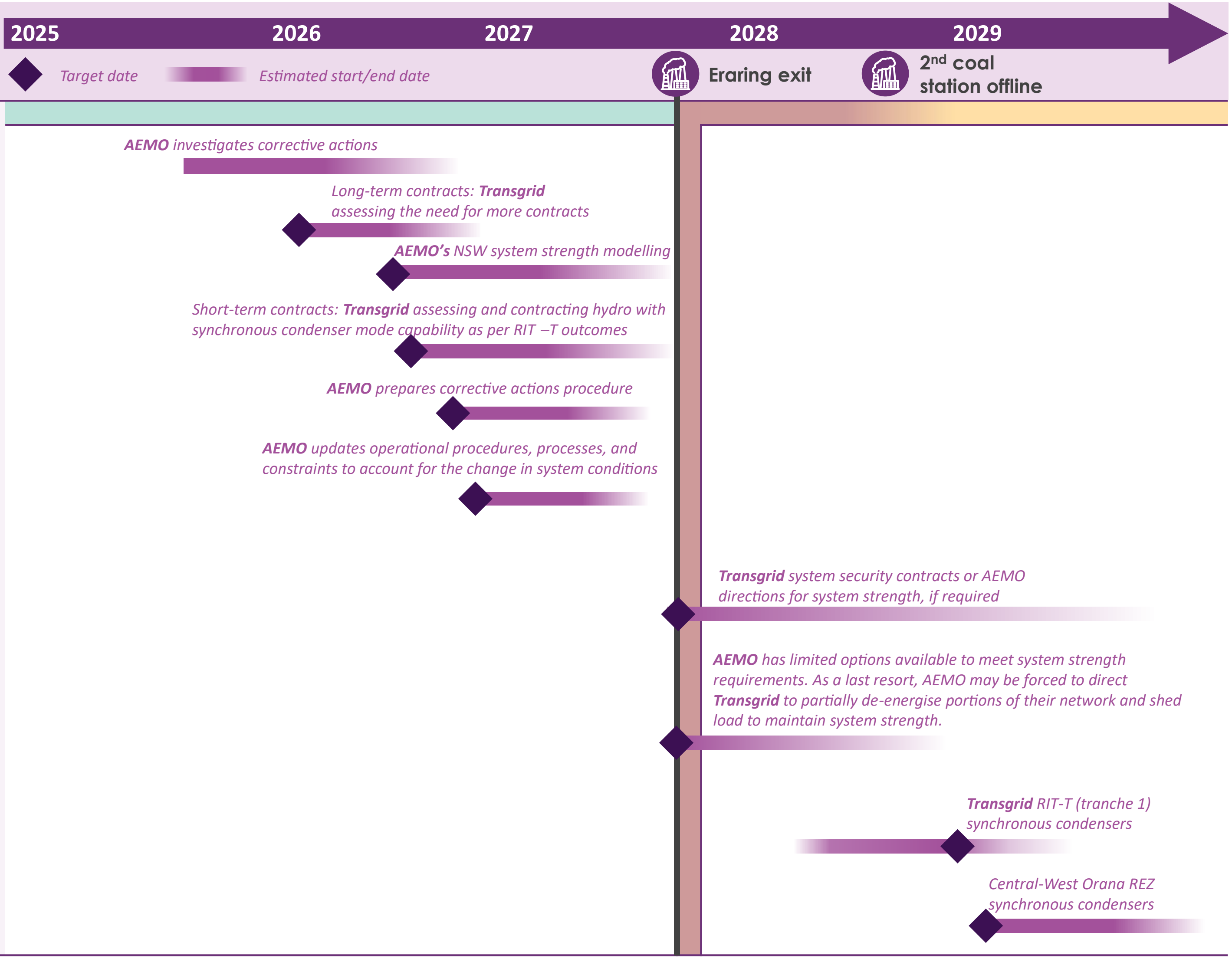
Since 2021, **AEMO's** security planning studies have identified the system strength requirements to avoid system strength deficits below minimum fault levels at system strength nodes in New South Wales, particularly Newcastle and Sydney West following closure of Eraring Power Station. Insufficient fault levels would potentially impact the correct operation of protection systems and hosting capacity for inverter-based resources in the vicinity of those nodes.

While **Transgrid**[A] and the **New South Wales Government**[B] are expediting delivery the first tranche of the synchronous condensers in **Transgrid**'s RIT-T, the delivery is currently scheduled about one year after Eraring's announced exit.

Before **Transgrid** delivers the synchronous condensers, deficits will need to be managed operationally by **Transgrid** and **AEMO**. This may include **AEMO** enabling TNSP security contracts (for hydro, gas and coal), issuing directions, and directing **Transgrid** to de-energise network assets.

As a precautionary measure, **AEMO** will work with **Transgrid** to prepare a procedure on which sections of the transmission network may be de-energised and consult with the New South Wales Jurisdictional System Security Coordinator (JSSC). **AEMO** will create constraints on IBR generation as needed, based on **Transgrid** limits advice, in some areas of the NSW region to maintain adequate short-circuit ratios (SCR) to ensure IBR stability.

AEMO anticipates the delivery, in full, of all planned system strength RIT-T synchronous condensers and Central-West Orana REZ synchronous condensers will meet minimum fault level requirements from 2030-31, which will enable future coal decommitments and exits.



AEMO investigates corrective actions

*Long-term contracts: **Transgrid** assessing the need for more contracts*

AEMO's NSW system strength modelling

*Short-term contracts: **Transgrid** assessing and contracting hydro with synchronous condenser mode capability as per RIT –T outcomes*

***AEMO** prepares corrective actions procedure*

***AEMO** updates operational procedures, processes, and constraints to account for the change in system conditions*

***Transgrid** system security contracts or AEMO directions for system strength, if required*

***AEMO** has limited options available to meet system strength requirements. As a last resort, AEMO may be forced to direct **Transgrid** to partially de-energise portions of their network and shed load to maintain system strength.*

***Transgrid** RIT-T (tranche 1) synchronous condensers*

Central-West Orana REZ synchronous condensers

A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

B. See https://gazette.nsw.gov.au/gazette/2025/9/2025-9_376-gazette.pdf

Eraring exit

Frequency and inertia

Ahead of commissioning of all **Transgrid's** RIT-T synchronous condensers, Eraring exit (current publicly announced as August 2027) is projected to create significant inertia deficits. **Transgrid** is investigating available options to meet its inertia requirements in the interim, including contracting services from existing synchronous machines[A].

Voltage control

It is expected that voltage control can be managed under system normal conditions following exit of Eraring Power Station. Emerging challenges are possible under high demand conditions, exacerbated by outage conditions. Further analysis is to be conducted by **AEMO** and **Transgrid**.

System restoration

System restoration options will be reduced following Eraring exit. In the short term, **AEMO** is confident there are sufficient restart options to meet the SRS. Longer term, additional SRAS may be required. System restart procedures will be updated in consultation with **Transgrid**.

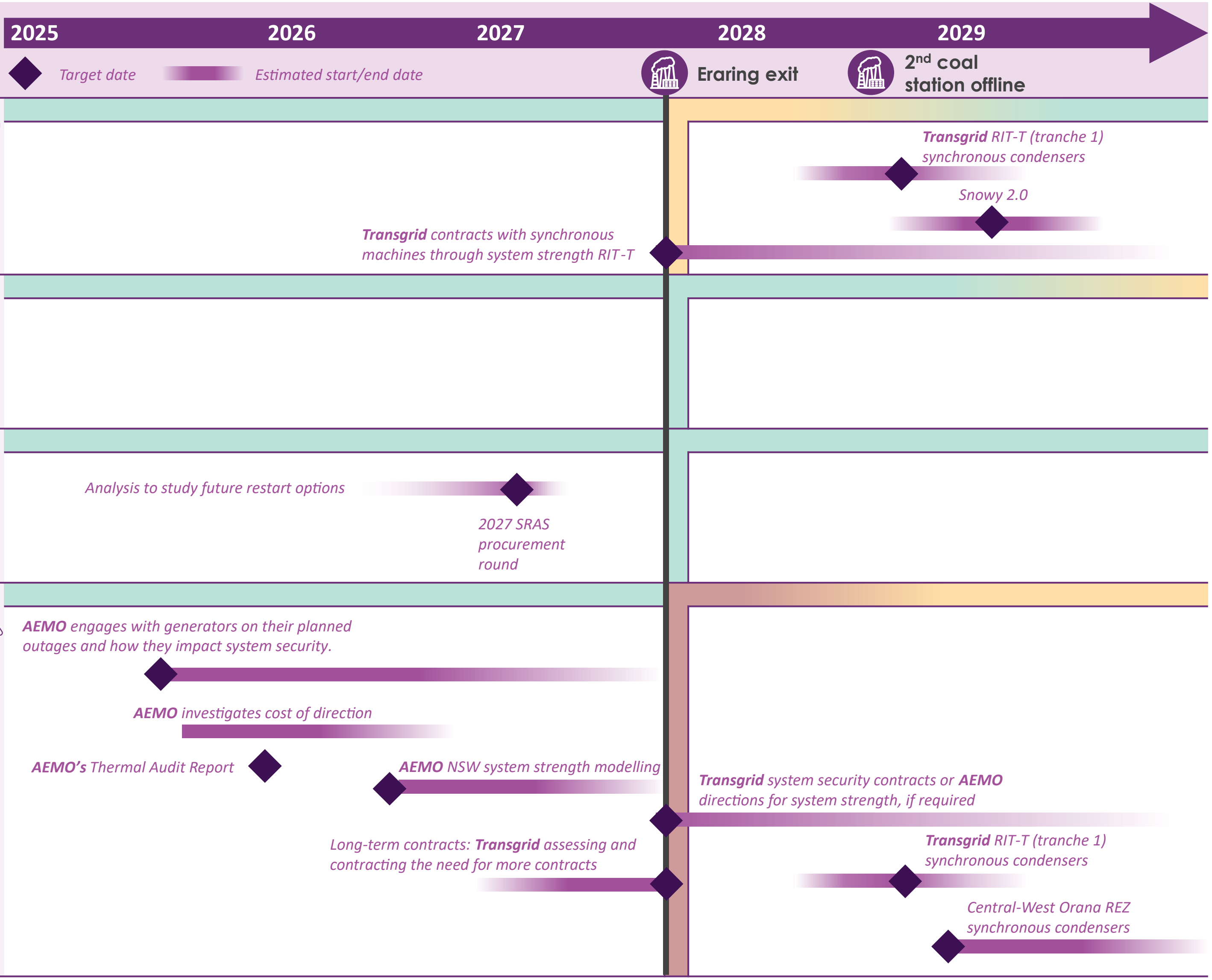
Operability – outage planning

Until new network and generation assets are delivered, Eraring's planned exit in August 2027 is expected to reduce margins for undertaking network and generator outages.

Transgrid[A] and **New South Wales Government**[B] are expediting delivery of the first tranche of synchronous condensers which will reduce reliance on the remaining synchronous generation fleet for system strength and increase margins for outage planning.

Until these solutions are delivered (expected 2028-29), **AEMO** will likely enable **Transgrid** contracts or issue directions as needed to meet system strength requirements.

Planned outages for network and generator maintenance as published in MTPASA (especially in Spring 2027) may have to be moved to ensure security and reliability of the power system. **AEMO** has very limited powers to coordinate generator outages in the medium term.



2025 2026 2027 2028 2029

◆ *Target date* *Estimated start/end date*

Eraring exit

2nd coal station offline

__Transgrid__ RIT-T (tranche 1) synchronous condensers

Snowy 2.0

__Transgrid__ contracts with synchronous machines through system strength RIT-T

Analysis to study future restart options

2027 SRAS procurement round

__AEMO__ engages with generators on their planned outages and how they impact system security.

__AEMO__ investigates cost of direction

__AEMO's__ Thermal Audit Report

__AEMO__ NSW system strength modelling

__Transgrid__ system security contracts or __AEMO__ directions for system strength, if required

Long-term contracts: __Transgrid__ assessing and contracting the need for more contracts

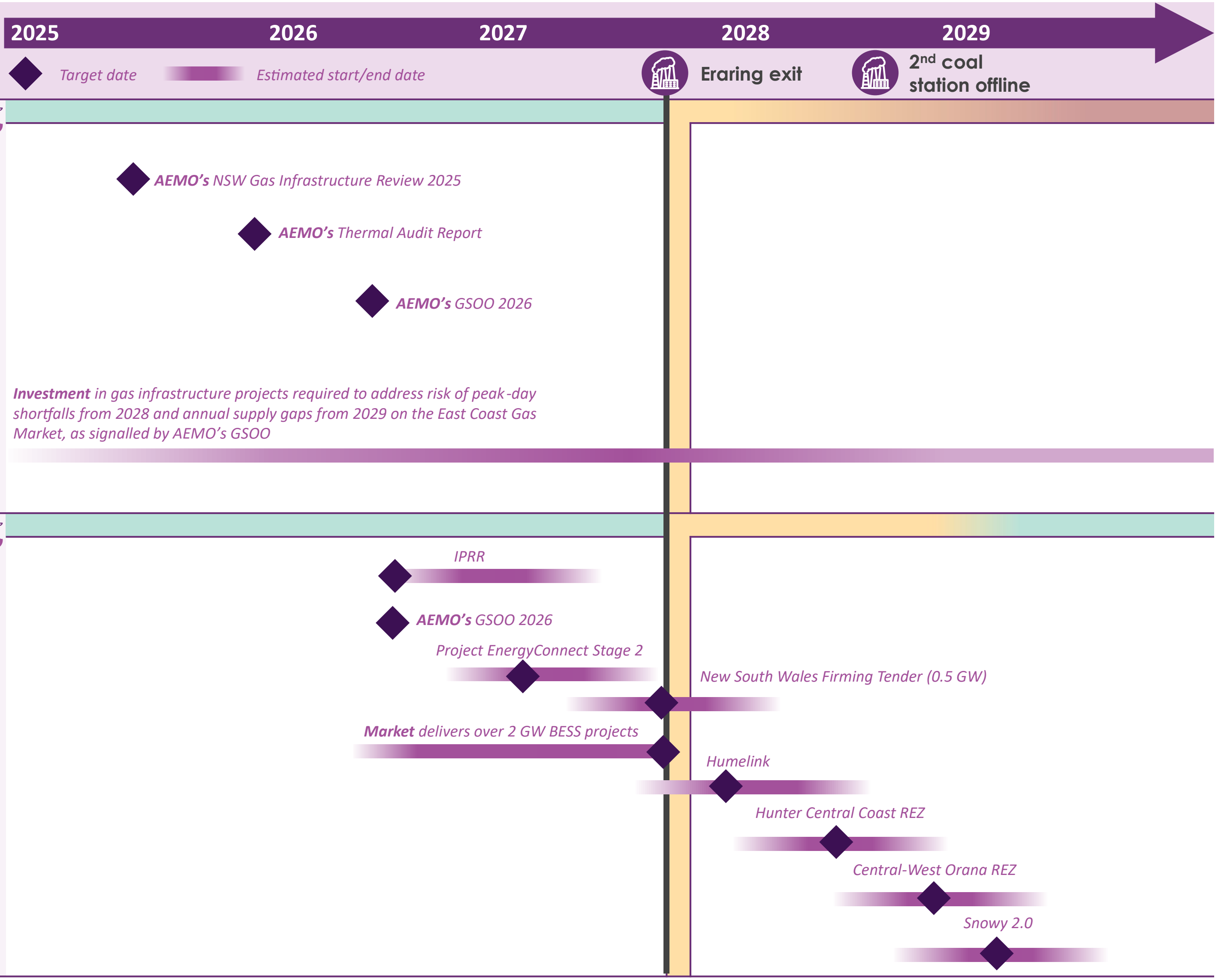
__Transgrid__ RIT-T (tranche 1) synchronous condensers

Central-West Orana REZ synchronous condensers

A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

B. See https://gazette.nsw.gov.au/gazette/2025/9/2025-9_376-gazette.pdf

Eraring exit



Resource adequacy – gas adequacy

Transgrid may contract gas-powered generators (GPG) to provide system security services. During operational timeframes, **AEMO** may enable system security contracts for GPG or need to direct GPG for system strength or reliability. This creates a dependency on availability of fuel for these generators.

GPG north of Sydney are currently limited by gas network constraints and are only able to generate using supply from dedicated gas storages, restricting their peak output run time using gas to ten hours at most. Gas supply, storage and pipeline constraints are risks to GPG availability until new supplies and gas network upgrades are delivered[A]. Some GPG facilities have diesel backup fuel, however supply chain factors may also limit this capability.

AEMO's GSOO[B] identifies investment opportunities in East Coast Gas Market infrastructure to address projected gas shortfalls and GPG availability.

Resource adequacy – reliability

While the 2025 ESOO forecasts that New South Wales meets the Reliability Standard following Eraring's planned exit, ESOO sensitivities for drought, planned outages, and tight gas supplies indicate challenging operating conditions during 2027-28 may create supply scarcity risks[C]. Until new forecast generation sources come online, reliability during the transition is increasingly exposed to concurrent planned outages of more than one facility as the power system becomes more reliant on remaining synchronous generation and utilises peaking generators more often. Concurrent generator outages planned for Spring 2027, submitted to MTPASA (as of November 2025), create risks of unserved energy, emphasising that outage management is critical as well as the on time and in full delivery of generation, storage and network solutions to maintain reliability.

Forecast reliability is anticipated to improve from **ASL** tendering of firming resources to meet 2027 Firming Tender[D]. **Market** to deliver 2027 Firming Tender generation on time and in full. Additional dispatchable and firming support to be provided by over 2 GW of committed and anticipated BESS projects, expected to be delivered between 2026 and Eraring exit.

[A] See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/ngir/new-south-wales-gas-infrastructure-review-may-2025.pdf

[B] See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

[C] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf

[D] See https://asl.org.au/tenders/tender-round-7-firming-infrastructure

2nd coal station potentially offline

2028-29

New South Wales

● Moderate Readiness

◆! Action required

Assessed

- **System strength** ◆!
- **Frequency and inertia** ◆!
- **Voltage control**
- **Operability** ◆!
- **Resource adequacy** ◆!

To be assessed

- **Transient and oscillatory stability**
- **System restoration**

Context

The 2024 Integrated System Plan (ISP) Step Change scenario anticipates that at least two 660 MW coal units may decommit from the market as early as July 2028[A]. Decommitment, such as two-shifting (lasting a few hours) or seasonal mothballing (up to months), may occur for a variety of economic reasons, such as sustained periods of low market price.

While decommitted units may still be available to return to market participation, the plant may be cold and could take hours or days to bring back online, making it unavailable for security or reliability support within operational timeframes. As these plants reach the end of their technical lives, decommitment may also be forced by unforeseen failures, lasting for an unknown length of time.

Impacts

The potential decommitment of two coal units in the New South Wales system as early as July 2028 would result in a further reduction in synchronous generation capacity, impacting all avenues of system security, reliability and operability. In particular:

- There may be insufficient synchronous units available to meet system strength until synchronous condensers are delivered in full. This will also limit the ability to take outages on major transmission elements and remaining coal generators.
- Resource adequacy concerns may arise from thermal constraints, limited replacement generation and gas supply constraints.
- Gas adequacy for GPG that could be required for both reliability, and to a lesser extent system strength, would be a growing risk.

While it is yet to be assessed in detail, AEMO anticipates that transient stability limits across key transmission flow paths would be reduced by such decommitment. In particular, the transfer capacity from Queensland to New South Wales could be reduced, further compounding supply scarcity risks.

Regardless of the cause for decommitment, it is prudent for industry to be prepare to operate the power system under such conditions.

Actions

While many in-flight and planned projects could address the security and reliability impacts of this transition point, they are unlikely to be delivered in full by July 2028. In which case, **Transgrid** may need to procure system security contracts and **AEMO** may need to activate **Transgrid's** system security contracts or issue directions, including the potential recall of decommitted station(s).

AEMO expects security to be delivered without intervention once the following actions are completed:

- **Transgrid**[B] and **New South Wales government**[C] fast-tracked delivery of first tranche synchronous condensers to provide critical system security services.
- **Snowy Hydro** delivery of Snowy 2.0, which will add significant energy storage and synchronous generation, improving system reliability and security.
- **ACEREZ, EnergyCo,** and **Ausgrid**, delivery of REZ network infrastructure buildout, including synchronous condensers, and **market participants** to complete REZ generation buildout. Completed, in-service REZ, such as CWO, will be critical to supporting system security and reliability.
- **ASL**[D] tenders to encourage investment in generation, firming, and long-duration storage.
- **Transgrid** and **EnergyCo** design and delivery of the Hunter Transmission Project[E]. This project will significantly improve transmission capacity into the Sydney-Newcastle-Wollongong load centre from REZ and Snowy scheme under peak load conditions and will become critical for system operability for further coal decommitments.

AEMO will support preparatory efforts by undertaking detailed transient and oscillatory stability studies, when appropriate, to quantify the impacts of progressive coal decommitment in New South Wales and the effectiveness of new augmentations.

A. See https://www.aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf

B. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

C. See https://gazette.nsw.gov.au/gazette/2025/9/2025-9_376-gazette.pdf

D. See https://asl.org.au/-/media/services/files/publications/iio-report/2025/2025-iio-report.pdf

E. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

2nd coal station potentially offline

2028-29

New South Wales

Moderate Readiness

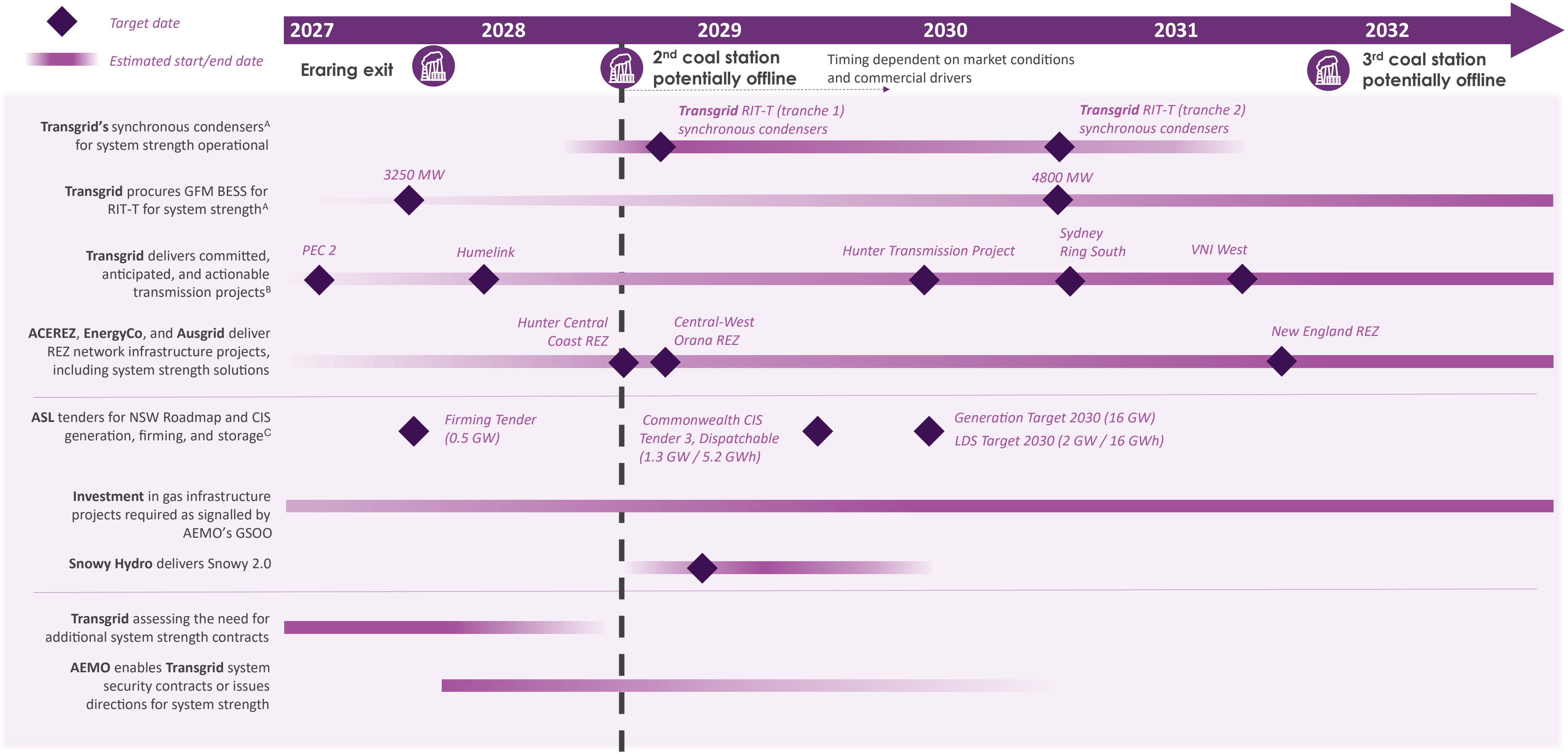
◆ Action required

Assessed

- System strength ◆
- Frequency and inertia ◆
- Voltage control
- Operability ◆
- Resource adequacy ◆

To be assessed

- Transient and oscillatory stability
- System restoration



◆ *Target date*

▬ *Estimated start/end date*

2027 | 2028 | 2029 | 2030 | 2031 | 2032

Eraring exit

2nd coal station potentially offline

Timing dependent on market conditions and commercial drivers

3rd coal station potentially offline

Transgrid's synchronous condensers[A] for system strength operational
- ◆ ***Transgrid*** *RIT-T (tranche 1) synchronous condensers*
- ◆ ***Transgrid*** *RIT-T (tranche 2) synchronous condensers*

Transgrid procures GFM BESS for RIT-T for system strength[A]
- ◆ *3250 MW*
- ◆ *4800 MW*

Transgrid delivers committed, anticipated, and actionable transmission projects[B]
- ◆ *PEC 2*
- ◆ *Humelink*
- ◆ *Hunter Transmission Project*
- ◆ *Sydney Ring South*
- ◆ *VNI West*

ACEREZ, **EnergyCo**, and **Ausgrid** deliver REZ network infrastructure projects, including system strength solutions
- ◆ *Hunter Central Coast REZ*
- ◆ *Central-West Orana REZ*
- ◆ *New England REZ*

ASL tenders for NSW Roadmap and CIS generation, firming, and storage[C]
- ◆ *Firming Tender (0.5 GW)*
- ◆ *Commonwealth CIS Tender 3, Dispatchable (1.3 GW / 5.2 GWh)*
- ◆ *Generation Target 2030 (16 GW)*
- ◆ *LDS Target 2030 (2 GW / 16 GWh)*

Investment in gas infrastructure projects required as signalled by AEMO's GSOO

Snowy Hydro delivers Snowy 2.0

Transgrid assessing the need for additional system strength contracts

AEMO enables **Transgrid** system security contracts or issues directions for system strength

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A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

B. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

C. See https://asl.org.au/-/media/services/files/publications/iio-report/2025/2025-iio-report.pdf

2nd coal station potentially offline

◆ Target date

▬ Estimated start/end date

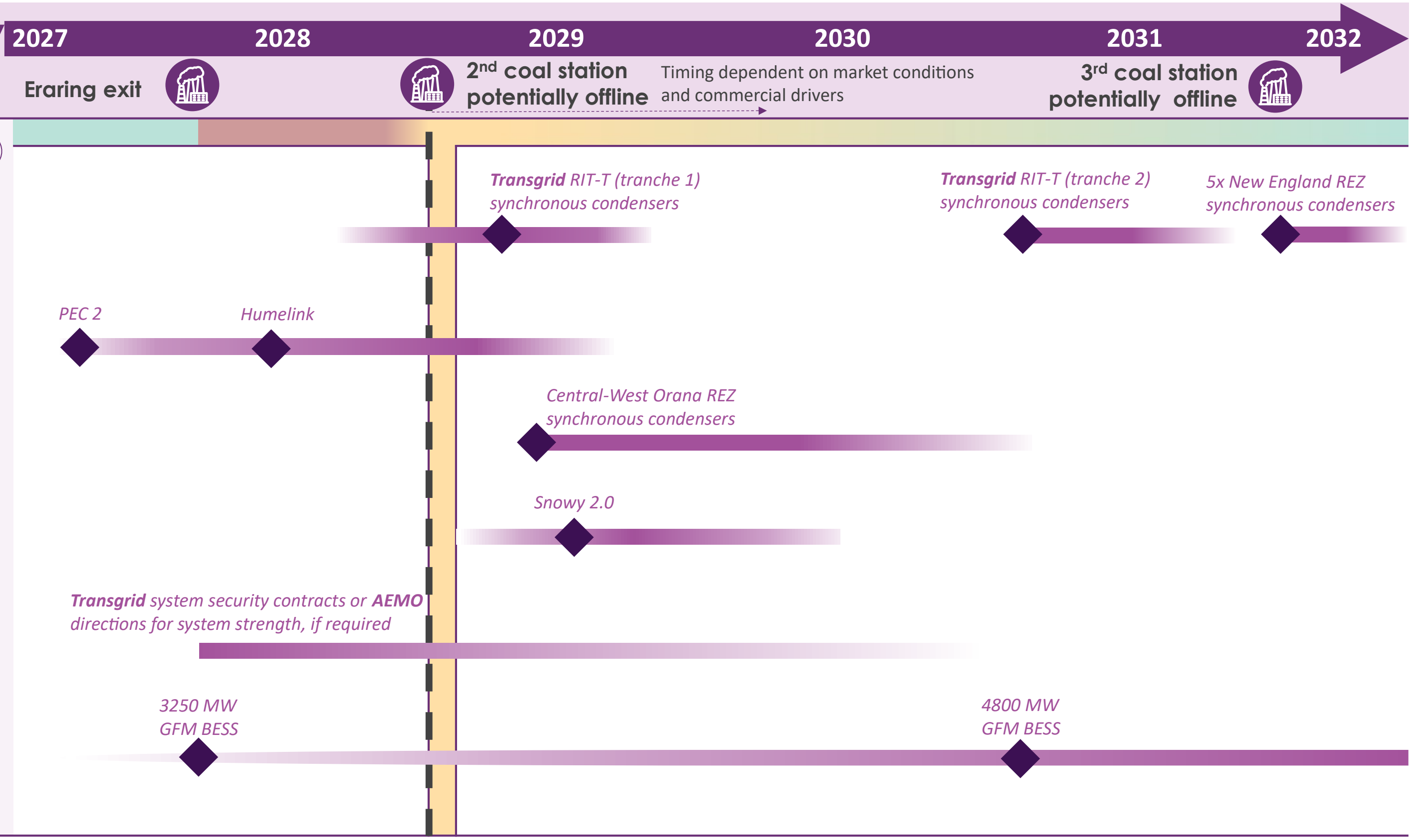
System strength

Maintaining minimum levels of system strength is contingent upon the on time and in full delivery of **Transgrid** and REZ synchronous condensers[A] and key transmission projects[B] to increase network connectivity. Insufficient available fault levels at system strength nodes could compromise the safe and correct operation of protection systems.

The provision of efficient system strength is achieved through a mix of solutions, including new grid-forming (GFM) inverter projects and other localized investments contracted to deliver these services. This diversified approach is essential to support the hosting capacity required for forecast grid-following IBR. However, delays or extended delivery timelines for REZ synchronous condensers could impact the timely provision of efficient system strength and so the ability to accommodate VRE and other grid-following plants.

Transgrid[A] and the **New South Wales Government**[C] are expediting the procurement of the first tranche of synchronous condensers as identified in **Transgrid**'s system strength RIT-T. Prior to this, **Transgrid** is intending to contract with existing synchronous generators to meet minimum level system strength needs, including between exit of Eraring and arrival of synchronous condensers. Currently, **Transgrid** is expected to have one provider of system strength from 2 December 2025. More will be considered by Transgrid to meet needs over coming years.

Where available, **AEMO** will enable **Transgrid** system security contracts as necessary to maintain system strength in operational timeframes. Otherwise **AEMO** may need to issue directions for system strength.



A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

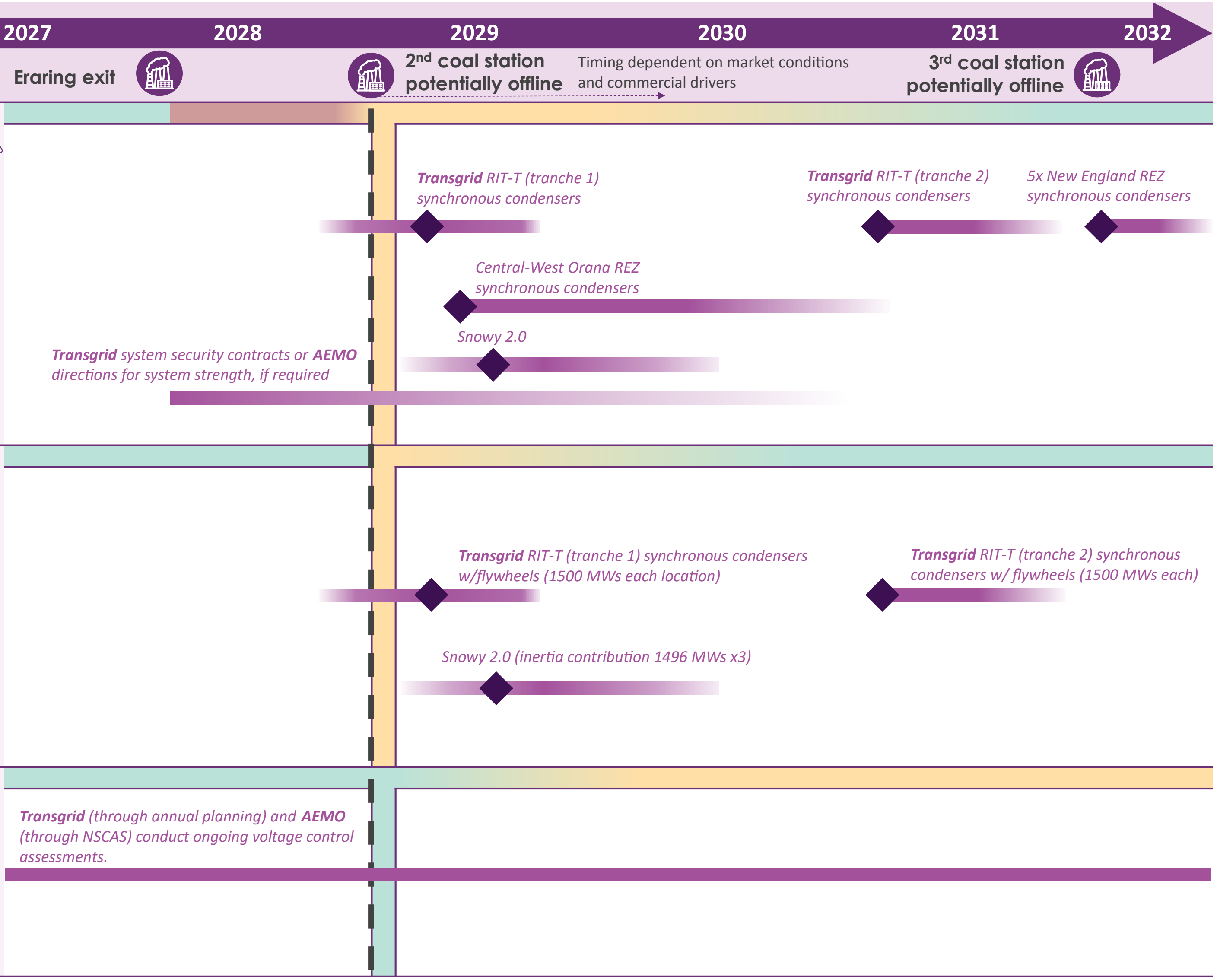
B. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

C. See https://gazette.nsw.gov.au/gazette/2025/9/2025-9_376-gazette.pdf

2nd coal station potentially offline

◆ *Target date*

▬ *Estimated start/end date*



2027 | 2028 | 2029 | 2030 | 2031 | 2032

Eraring exit

2nd coal station potentially offline

Timing dependent on market conditions and commercial drivers

3rd coal station potentially offline

Operability – outage planning

Should this transition point occur before the in-full commissioning of Transgrid RIT-T first tranche synchronous condensers, ability to undertake network outages could be reduced. Planned outages for network and generator maintenance may have to be deferred to ensure sufficient fault levels are available.

Transgrid[A] and **New South Wales government**[B] are expediting delivery of RIT-T first tranche synchronous condensers for system security. **Transgrid** to target on time delivery of all committed, anticipated, and actionable transmission projects[C]. **ACEREZ** and **EnergyCo** to actively progress the on time delivery of REZ and associated synchronous condensers. **AEMO** will defer outages and enable **Transgrid** system security contracts or issue directions as necessary to maintain security and reliability.

__Transgrid__ RIT-T (tranche 1) synchronous condensers

__Transgrid__ RIT-T (tranche 2) synchronous condensers

5x New England REZ synchronous condensers

Central-West Orana REZ synchronous condensers

Snowy 2.0

__Transgrid__ system security contracts or __AEMO__ directions for system strength, if required

Frequency and inertia

Prior to delivery of new flywheel-equipped synchronous condensers and other synchronous plant, the exit and potential decommitment of coal plant is expected to negatively impact inertia levels.

To address declining levels of inertia, **Transgrid**[A] and **New South Wales government**[B] are expediting delivery the first tranche of RIT-T synchronous condensers equipped with flywheels, which are expected to meet New South Wales inertia requirement of 9600 MWs in full. **Transgrid** may contract GFM BESS in the future to provide synthetic inertia responses.

Snowy Hydro completion of Snowy 2.0 in 2029 is expected to further contribute to meeting inertia requirements.

__Transgrid__ RIT-T (tranche 1) synchronous condensers w/flywheels (1500 MWs each location)

__Transgrid__ RIT-T (tranche 2) synchronous condensers w/ flywheels (1500 MWs each)

Snowy 2.0 (inertia contribution 1496 MWs x3)

Voltage control

If anticipated transmission and generation projects are not delivered prior to this potential transition point, emerging voltage control challenges have been identified under NSCAS for high demand conditions in New South Wales. It is expected that delivery of actionable transmission projects and securing appropriately located generation supply would alleviate emerging voltage control challenges around the Sydney load centre. **AEMO** will continue to work with **Transgrid** to assess.

__Transgrid__ (through annual planning) and __AEMO__ (through NSCAS) conduct ongoing voltage control assessments.

A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

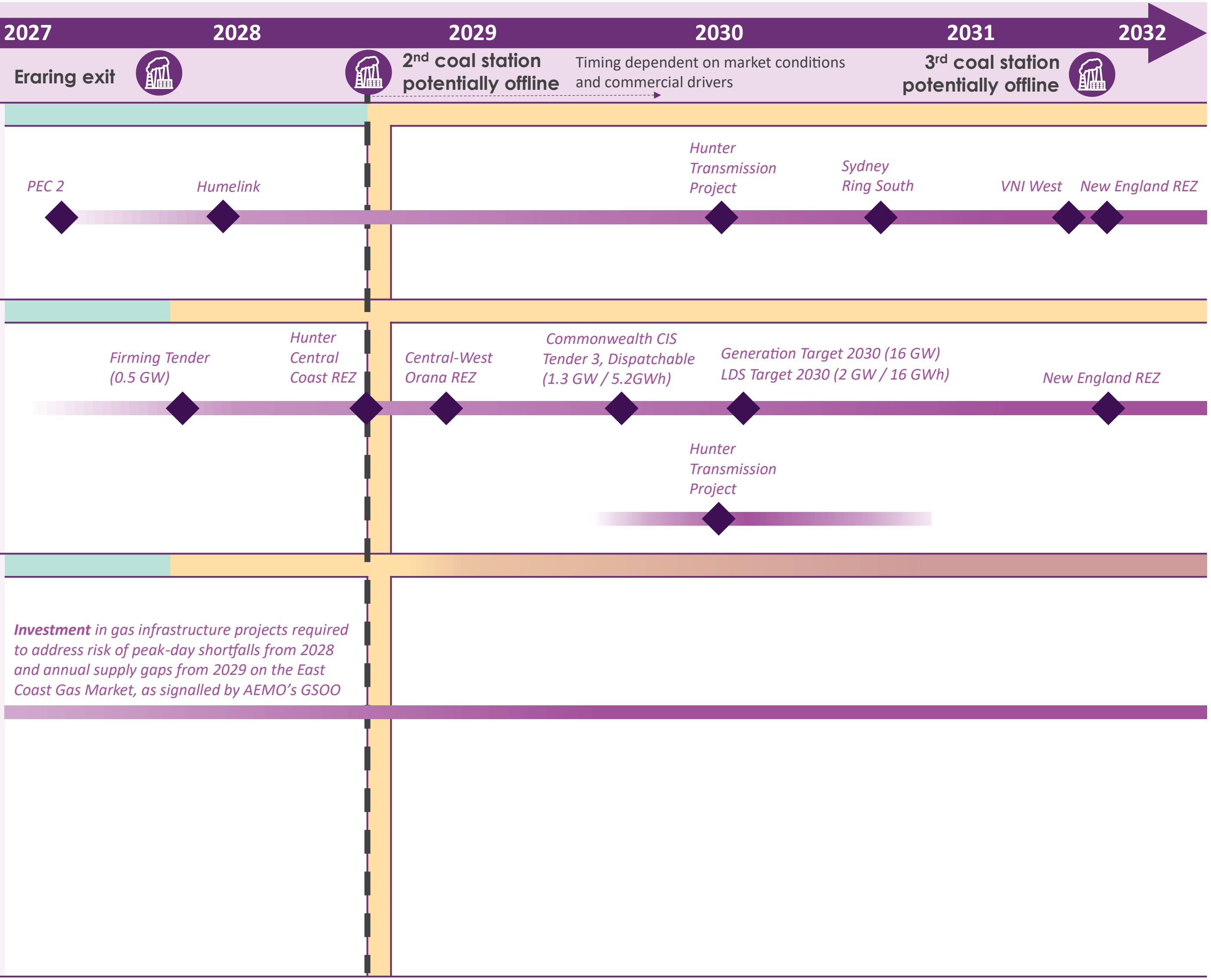
B. See https://gazette.nsw.gov.au/gazette/2025/9/2025-9_376-gazette.pdf

C. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

2nd coal station potentially offline

◆ *Target date*

Estimated start/end date



Investment in gas infrastructure projects required to address risk of peak-day shortfalls from 2028 and annual supply gaps from 2029 on the East Coast Gas Market, as signalled by AEMO's GSOO

Resource adequacy – thermal limits

Should this transition point occur prior to the delivery of the Hunter Transmission Project, there exists a risk that parts of the network could be exposed to thermal overload under maximum demand conditions. Major thermal risks to the transmission network are projected to be addressed by the detailed design and delivery of committed, anticipated, and actionable network projects by **Transgrid**[A].

Resource adequacy – reliability

2025 ESOO[B] sensitivities of committed and anticipated projects were conducted for planned generator maintenance, drought and gas supply shortfall scenarios. Results show reliability outside the Reliability Standard for 2027-28 with gas shortfalls and planned generator maintenance, and from 2027-2028 onward for drought conditions. Progression towards NSW Roadmap and CIS generation targets by **ASL**[C,D], as well as REZ developments by **ACEREZ**, **EnergyCo**, and **Ausgrid** are expected to maintain reliability within the Reliability Standard if delivered on time and in full.

Resource adequacy – gas adequacy

Reliance on GPG to provide peaking, firming, and system restart services is expected to increase and become increasingly critical as coal generation exits the market. The 2025 GSOO[E] forecasts an increasing risk of peak-day shortfalls from 2028 and annual supply gaps from 2029, potentially impacting GPG availability for reliability, particularly over winter during VRE lulls.

GSOO identifies investment opportunities in East Coast Gas Market infrastructure and GPG availability. GPG north of Sydney are currently limited by gas network constraints and are only able to generate using supply from dedicated gas storages, restricting peak output run time using gas to ten hours at most[F]. The GSOO forecasts gas adequacy to become an increasing concern and urgent investment is required to improve gas supplies from 2029 onwards.

A. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

B. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf

C. See https://asl.org.au/-/media/services/files/publications/iio-report/2025/2025-iio-report.pdf

D. See https://asl.org.au/tenders/cis-tender-3-nem-dispatchable

E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

F. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/ngir/new-south-wales-gas-infrastructure-review-may-2025.pdf

3rd coal station potentially offline

2031-32

New South Wales

● Moderate readiness

◆ Action required

Assessed

System strength

Frequency and inertia

Resource adequacy ◆

Voltage control

To be assessed

Operability

Transient and oscillatory stability

System restoration

Context

The 2024 ISP Step Change scenario[A] projects that by 2031-32 there may times when the 3rd New South Wales coal station is offline for an extended period of time (such as seasonal mothballing), leaving only two coal units in the system. This is two years earlier than publicly announced retirement dates.

During such times, AEMO must be ready to securely and reliably operate the New South Wales region with zero coal units online, as one of the remaining coal units may be offline for maintenance and the other generating unit may trip offline unexpectedly.

Impacts

The operational envelope when there are only two coal units online, with the credible risk of operating with no coal units online, will be distinctly different to today.

Power flows will shift as generation from around the region is delivered to the Sydney-Newcastle-Wollongong load centre, highlighting the criticality of Hunter Transmission Project and Sydney Ring South projects to alleviate thermal constraints and improve transfer capability.

Transgrid's System strength RIT-T is expected to deliver sufficient solutions to meet minimum and efficient fault level requirements with additional support coming from REZ system strength solutions[B].

Actions

There are many actions in-flight and in planning that could support security when only two New South Wales coal stations are online, as well as the credible risk of operating with no coal units online. If these are delivered on time and in full, AEMO expects security to be maintained without interventions.

Actions identified by the ISP as the lowest cost pathway to replace coal generation, and by other initiatives, include:

- **Transgrid**[B] to deliver tranche two synchronous condensers with flywheels to support system strength and inertia ahead of this transition point. Additionally, delivering committed, anticipated, and actionable major network projects to support load growth, generation build-out, and interregional support[C].
- **EnergyCo** delivering New England REZ infrastructure and synchronous condensers to support system security and reliability[D]. Additionally, facilitating the timely connection of REZ generation to support reliability.
- **ASL** to continue tendering to encourage investment and ensure delivery to identified targets for generation, firming, and long-duration storage[E].

While it is possible that these may be delivered in full by 2031-32, there are significant delivery risks, as with all major infrastructure projects. There are opportunities now to explore active management of the risks to ensure assets are built by target dates.

AEMO is preparing for this transition point by studying security and operability aspects of operating the system with no coal online, including transient and oscillatory stability analyses, as well as planning for system restoration. AEMO also provides the Enhanced Locational Information report[F] to help direct the location of investments.

A. See https://www.aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf

C. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

E. See https://asl.org.au/-/media/services/files/publications/iio-report/2025/2025-iio-report.pdf

B. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

D. See https://www.energyco.nsw.gov.au/ne-rez

F. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/enhanced-locational-information/2025/2025-enhanced-locational-information-report.pdf

3rd coal station potentially offline

2031-32 | New South Wales | ● Moderate readiness

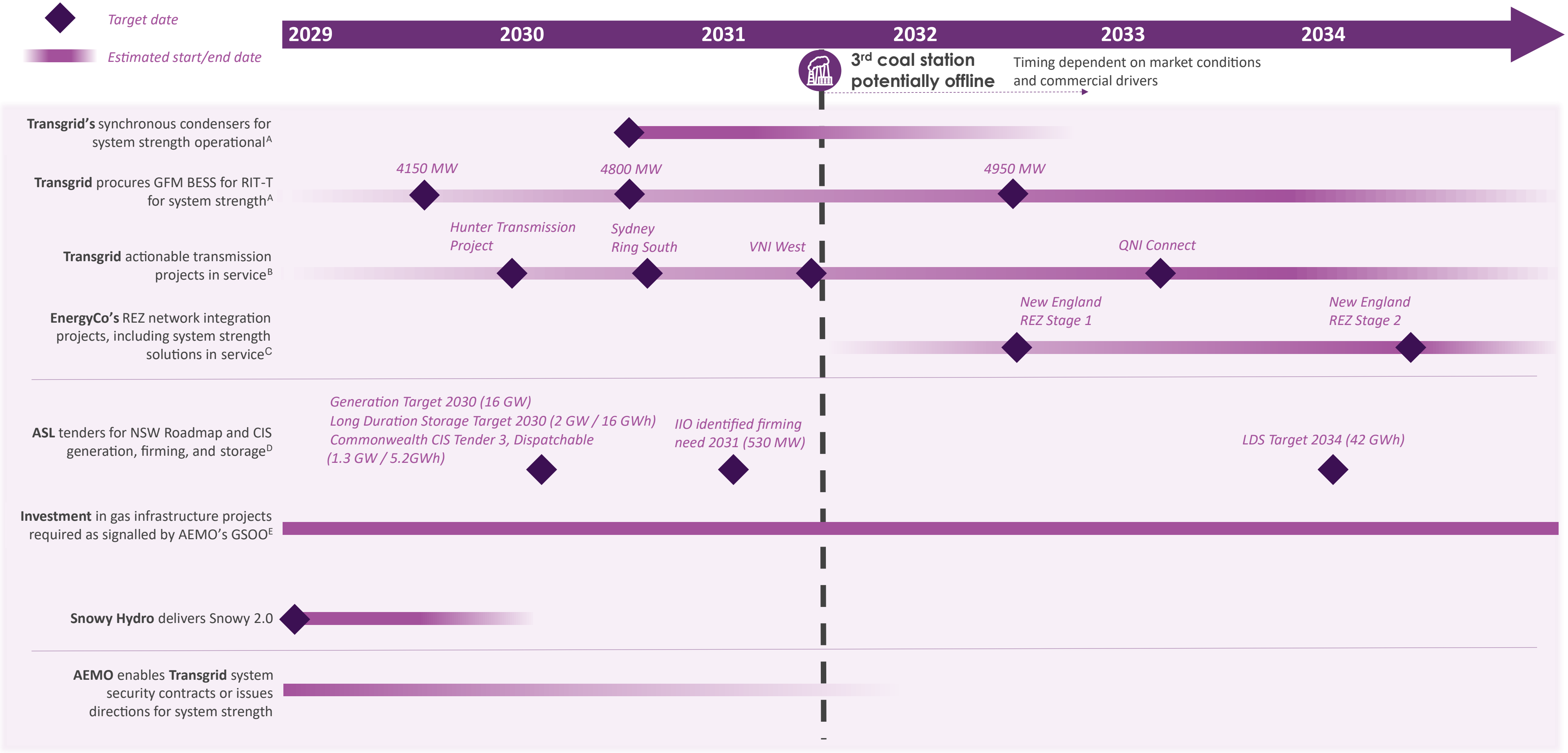
◆ Action required

Assessed: System strength | Frequency and inertia | Resource adequacy ◆ | Voltage control

To be assessed: Operability | Transient and oscillatory stability | System restoration

◆ *Target date*

▬ *Estimated start/end date*



Transgrid's synchronous condensers for system strength operational[A]

Transgrid procures GFM BESS for RIT-T for system strength[A]

Transgrid actionable transmission projects in service[B]

EnergyCo's REZ network integration projects, including system strength solutions in service[C]

ASL tenders for NSW Roadmap and CIS generation, firming, and storage[D]

Investment in gas infrastructure projects required as signalled by AEMO's GSOO[E]

Snowy Hydro delivers Snowy 2.0

AEMO enables **Transgrid** system security contracts or issues directions for system strength

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A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

B. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

C. See https://www.energyco.nsw.gov.au/ne-rez

D. See https://asl.org.au/-/media/services/files/publications/iio-report/2025/2025-iio-report.pdf

E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

3rd coal station potentially offline

System strength

Maintaining minimum levels of system strength for this transition point, including potential operation with no coal units online, is contingent upon the on time and in full delivery of Transgrid and REZ synchronous condensers[A] to provide synchronous fault levels, and key transmission projects to improve network connectivity[B].

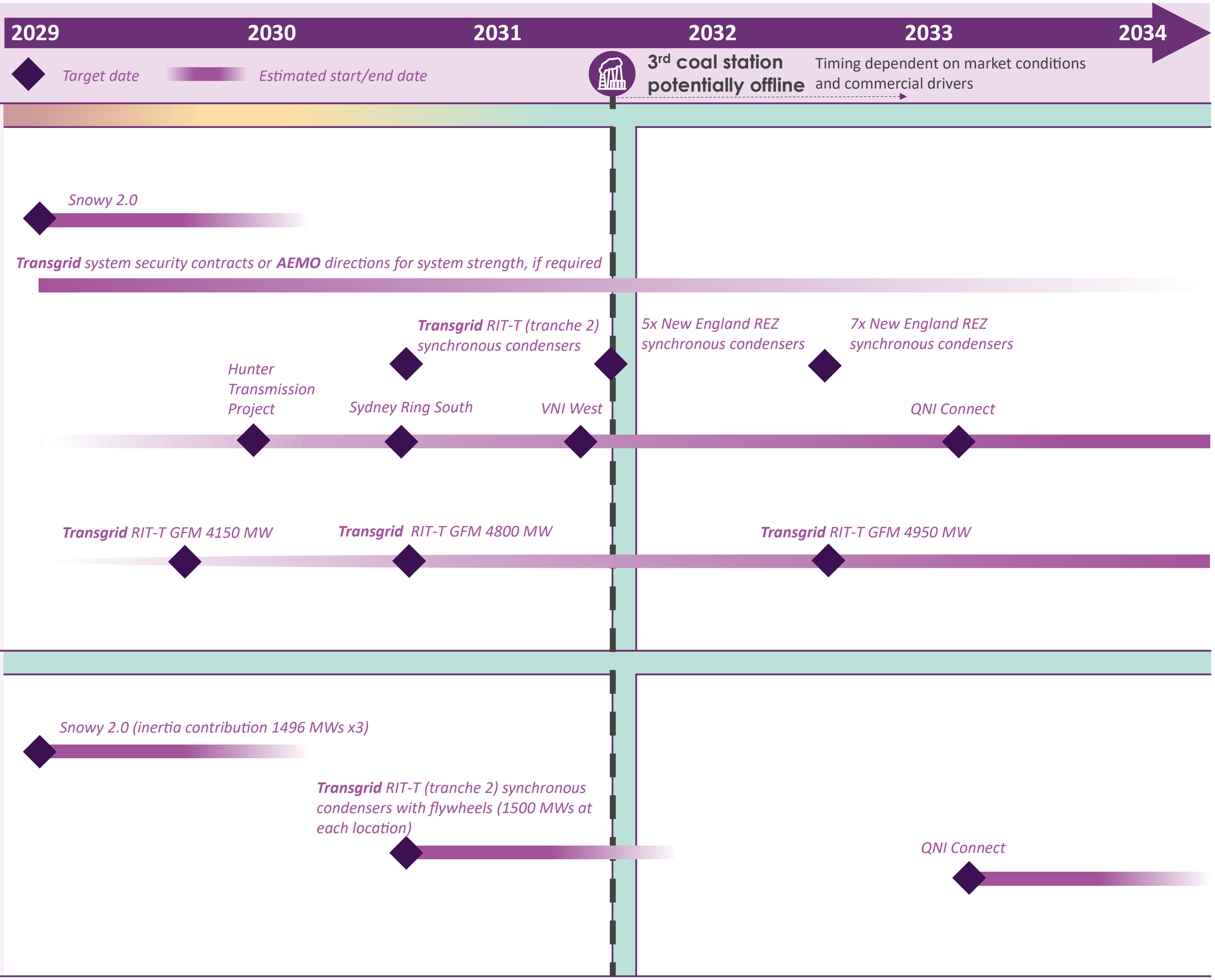
Currently, **Transgrid** is progressing delivery of RIT-T for system strength solutions with the second tranche of synchronous condensers expected to be delivered in full by 2030-31[A]. Delays in delivery of these or network projects risks insufficient available fault levels at system strength nodes throughout New South Wales, compromising the safe and correct operation of protection systems and supportability of existing IBR.

In operational timeframes, **AEMO** may need to enable **Transgrid** system security contracts where available or issue directions to maintain system strength if system strength solutions at not delivered on time.

Provision of efficient system strength relies on forecast pipeline of new grid-forming inverter projects or other localised investments providing these services under contract to provide hosting capacity for forecast grid-following IBR. Delays and/or lengthy delivery schedules of REZ synchronous condensers are possible, which may impact the provision of efficient system strength and hosting capacity of VRE and other grid-following plant.

Frequency and inertia

Frequency control and inertia are not expected to be materially impacted by this transition point. **Snowy Hydro** completion of Snowy 2.0 is expected to provide inertia while online, and **Transgrid** synchronous condensers equipped with flywheels[A] are expected to satisfy New South Wales inertia sub-network allocation requirements of 9,600 MWs following their delivery in full.



A. See https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf

B. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

3rd coal station potentially offline

Voltage control

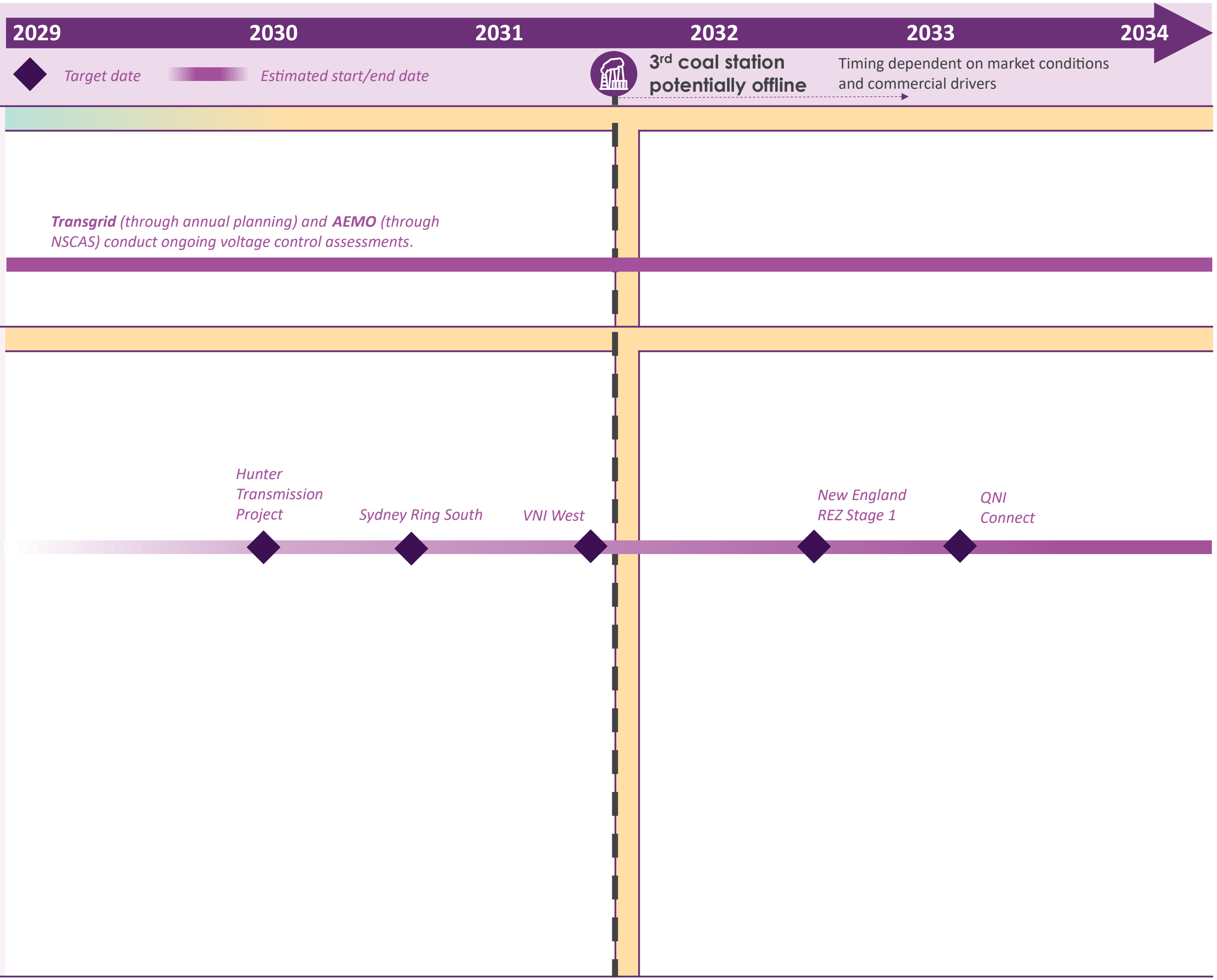
If anticipated transmission and generation projects are not delivered prior to this transition point, emerging voltage control challenges have been identified under NSCAS for high demand conditions in New South Wales. It is expected that delivery of actionable projects[A] will be needed and securing generation supply will be critical to alleviating emerging voltage control challenges around the Sydney load centre. **AEMO** will continue to work with **Transgrid** to assess.

Resource adequacy – thermal limits

This potential transition point results in significant shifts to transmission flows during peak demand scenarios and thermal risks to the transmission network are expected. All major transmission projects critical to enabling this transition point are currently only considered actionable and carry significant uncertainty in delivery. Detailed and coordinated design of these projects will be required to address thermal and reliability risks in full.

Transgrid to drive delivery of actionable network projects on time and in full[A]. Hunter Transmission Project and Sydney Ring South project provides needed capacity to support reliability and reduce transmission constraints into Sydney and Newcastle load centres.

To optimize the utilization of transmission infrastructure and reduce the risk of network overloads during peak demand periods, firming generation should be strategically located near the Sydney and Newcastle load centres[B]. The operational availability of some of these resources may be constrained by factors such as gas supply adequacy[C] and BESS state-of-charge, both of which require active monitoring and management within operational timeframes.



2029 2030 2031 2032 2033 2034

◆ *Target date*

Estimated start/end date

3rd coal station potentially offline

Timing dependent on market conditions and commercial drivers

***Transgrid** (through annual planning) and **AEMO** (through NSCAS) conduct ongoing voltage control assessments.*

Hunter Transmission Project

Sydney Ring South

VNI West

New England REZ Stage 1

QNI Connect

A. See https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf

B. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/enhanced-locational-information/2025/2025-enhanced-locational-information-report.pdf

C. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/ngir/new-south-wales-gas-infrastructure-review-may-2025.pdf

3rd coal station potentially offline

Resource adequacy – reliability

The 2025 ESOO October update[A] forecasts the current pipeline of committed and anticipated projects is insufficient to meet the Reliability Standard by 2031-32, although the outlook is improved with additional government schemes and actionable projects, covering approximately 12 GW of additional generation capacity.

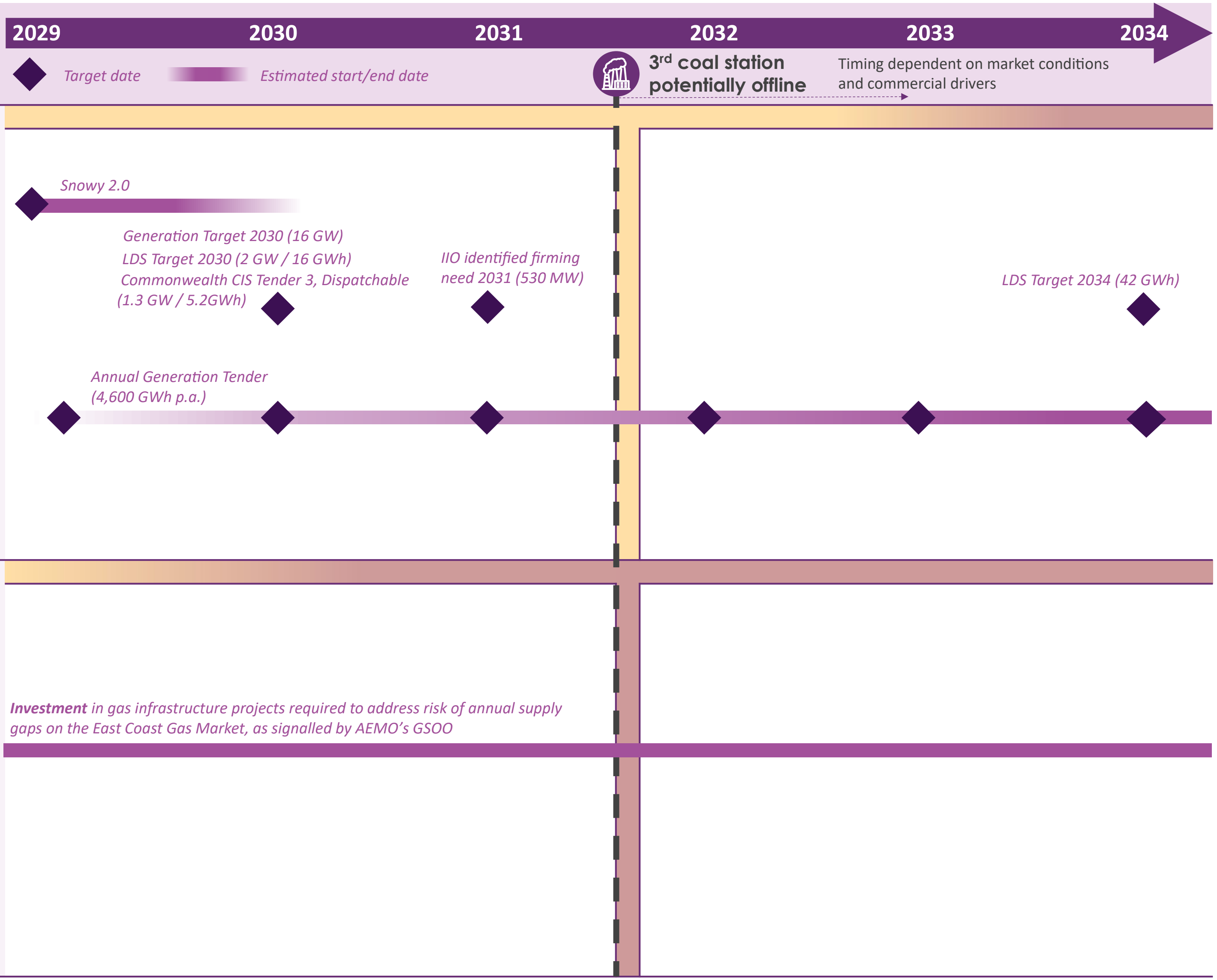
However, this is not resilient to sensitivities such as gas shortfalls, uncoordinated generator maintenance, and drought conditions, forecasted to exceed the Reliability Standard in 2032-33[B]. As the ESOO uses announced retirement dates, supply adequacy may be further impacted by earlier coal decommitment, leading to equal or worse outcomes.

It is therefore critical that successful project from past tenders are delivered on time and **ASL**[C] continues tendering to support investment to meet the IIO Development Pathway. The IIO report identified a need for additional firming infrastructure by 2031, however the specific volume and timing of this would be impacted by many assumptions such as the retirement timing of existing generation, the delivery timing of new generation and network projects, and demand-side factors.

Resource adequacy – gas adequacy

Reliance on GPG to provide peaking, firming, and system restart services is expected to increase and become increasingly critical as coal generation exits the market. The 2025 GSOO[D] forecasts an increasing risk of peak-day shortfalls from 2028 and annual supply gaps from 2029, impacting GPG supportability for reliability, particularly during VRE lulls.

GSOO identifies investment opportunities in East Coast Gas Market infrastructure to address projected gas shortfalls and GPG availability. GPG north of Sydney are currently limited by gas network constraints and are only able to generate using supply from dedicated gas storages, restricting peak output run time using gas to ten hours at most[E]. The GSOO forecasts gas adequacy to become an increasing concern and urgent investment is required from 2029 onwards.



2029 | 2030 | 2031 | 2032 | 2033 | 2034

◆ *Target date*

Estimated start/end date

3rd coal station potentially offline

Timing dependent on market conditions and commercial drivers

Snowy 2.0

Generation Target 2030 (16 GW)
LDS Target 2030 (2 GW / 16 GWh)
Commonwealth CIS Tender 3, Dispatchable (1.3 GW / 5.2GWh)

IIO identified firming need 2031 (530 MW)

LDS Target 2034 (42 GWh)

Annual Generation Tender (4,600 GWh p.a.)

***Investment** in gas infrastructure projects required to address risk of annual supply gaps on the East Coast Gas Market, as signalled by AEMO's GSOO*

A. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/october-2025-update-to-the-2025-esoo.pdf

B. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf

C. See https://asl.org.au/-/media/services/files/publications/iio-report/2025/2025-iio-report.pdf

D. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/ngir/new-south-wales-gas-infrastructure-review-may-2025.pdf

Queensland

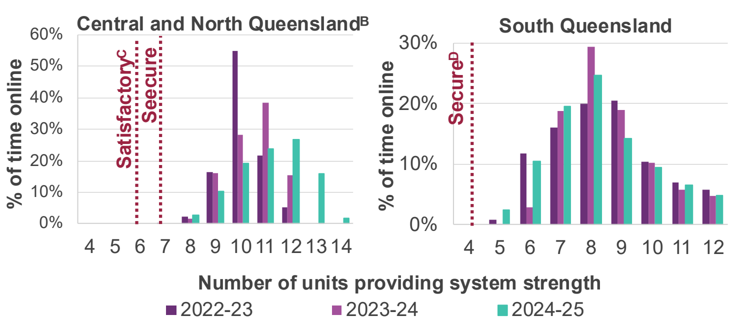
Context

Queensland's energy system is progressing towards an increasing mix of renewables and storage backed by gas powered generation. Queensland has the youngest coal fleet in the NEM with many Queensland coal stations not close to their end of life. The Queensland Energy Roadmap 2025 details the state's Electricity Maintenance Guarantee for the state-owned synchronous fleet for system security and reliability needs.

Irrespective, economic factors (including interregional impacts) determining the operational behaviour, availability, and long-term viability of Queensland's coal means that it remains prudent to plan for system security ahead of publicly announced retirement dates. AEMO's 2024 ISP modelling suggests that there may potentially be times when a coal station is taken offline for commercial reasons as early as 2027 -28. Additionally, AEMO has received advice from CS Energy of the potential for market exit of Gladstone Power Station in March 2029, while Callide B Power Station has had its exit date deferred until at least 2031.

Minimum System Load (MSL) conditions are projected to increase, with MSL2[A] conditions forecast to occur in system normal conditions from Spring 2026. New BESS may reduce the MSL threshold from Winter 2026.

Available system strength units are above security limits



Coal decommitment will reduce the number of units providing system strength

Network upgrade and synchronous condensers will reduce limit

Security challenges

Queensland's minimum operational demand is projected to decline over the next 5 years by 250MW a year. Despite actions, there remains an urgent need for increased emergency DPV backstop capacity in Queensland to ensure system security can be maintained in plausible worst-case conditions without wide-spread customer outages.

For typical system normal conditions, if system security investments that reduce minimum synchronous generator unit requirements are delivered on time and in full and there is enhanced flexibility of CER to manage output in the middle of the day, the incidences for DNSPs to enact mechanisms (such as emergency backstop) will remain rare. Earlier than anticipated decommitment of coal could pose security risks unless key security infrastructure is operational ahead of these decommitments.

The announced potential closure of Gladstone Power Station poses localised system strength and thermal constraint risks which are being mitigated by Powerlink through the Gladstone Priority Transmission Investment project.

Actions

- **Queensland Government** and **NSPs** to urgently consider expanding the coverage of active management capabilities to PV installations <10kVA and continue urgent measures to improve compliance with existing mechanisms.
- **Powerlink's** investment pipeline, including Gladstone PTI, Copperstring network upgrades, and synchronous condensers, are required to meet uncertainty in coal decommitment. On time and in full delivery of these projects is critical to allow the system to adapt to major transitions in generation mix and market dynamics, while ensuring system security.
- Following the investment pipeline becoming operational, coal plants may no longer be required to be online for system security and instead be upgraded to enable more flexible plant operations that support daily or seasonal reliability needs. This would reduce MSL thresholds and enable the market to operate more efficiently, with reduced security interventions and curtailments, thereby lowering energy costs for consumers.

A. In MSL2 conditions the power system is one credible load contingency away from requiring immediate action from AEMO and DNSPs to increase demand.

C. If the minimum 7 synchronous units (between Stanwell PS, Gladstone, Callide B and Callide C) for secure operation is not achieved, minimum required fault levels may be maintained with fast start gas or hydro units.

B. Contribution shown from Stanwell PS, Gladstone, Callide B and Callide C. The median number of available synchronous units increased from 10 units in 2022-23 to 12 units in 2024-25 due to return to service of Callide C units.

D. Secure requirement for South Queensland is satisfied through a combination of coal, hydro and gas units. Coal units contribute greater proportion to system strength, compared to hydro and gas units. A minimum combination of 4 synchronous generating units is required to satisfy minimum fault level requirements in South Queensland.

Queensland

REGIONAL DEVELOPMENTS Now	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Synchronous generator capacity change *Annual capacity changes (MW)*		+250		-1,680		-595		-292	-117	-138
Committed and anticipated IBR *Annual capacity changes (MW)*	+3,846	+400	+1,465	+598	*Future project details periodically evaluated in NEM generation information processes*					
IBR forecasts (*Sets efficient Sys. Strength level*) *Annual capacity changes (MW)*	+3,846	+400	+3,560	+1,952	+679	+570	+919	+594	+947	+810

Transmission augmentation[A,B]

● Committed/anticipated

● RIT-T in progress/actionable

● Townsville GT – synchronous condenser mode conversion (already in service)

Gladstone PTI Project

CopperString

QNI Connect

System strength RIT-T ● Tranche 1 → ● Tranche 2 → ● Tranche 3 → ● Tranche 4

Transition Points

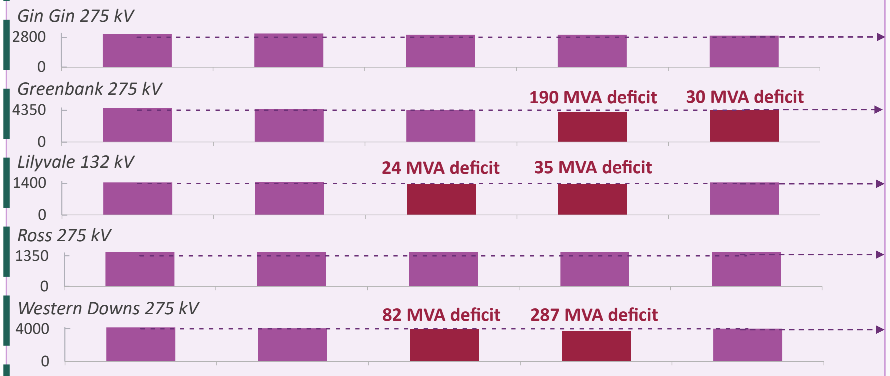
Qld MSL

1st coal station potentially offline

Gladstone Power Station Exit

AEMO'S CURRENT OUTLOOK	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Assessment horizon	***NSCAS assessment** (See Appendix 2)*					***Long term assessment***				

System strength – *nodal assessment*
(minimum fault current in MVA)

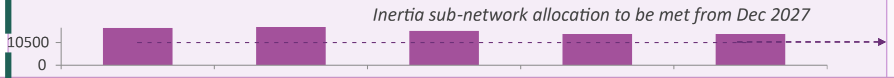


Long-term, system strength requirements are managed by Powerlink through the RIT-T framework.

Powerlink's RIT-T has concluded the Project Assessment Conclusions Report phase, published in June 2025, and initial stages of procurement are underway.

The preferred portfolio option features the delivery of synchronous condensers in four tranches between March 2029 and June 2034. Contracts with synchronous machines will be used to manage system strength in the interim.

Inertia (MWs)



Long-term inertia managed by RIT-T synchronous condensers and IBR participation in frequency market providing sufficient inertia and frequency support.

Thermal and voltage

No thermal loading or voltage control gaps identified

Long term voltage and thermal risks to be mainly addressed by Gladstone PTI, however additional future remediation may be needed.

------ Requirements ▨ Available level 🟥 Deficit ⚠ NSCAS Gap

[A] See https://www.powerlink.com.au/sites/default/files/2025-11/Transmission%20Annual%20Planning%20Report%20-%202025_0.pdf

[B] See https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf

Minimum System Load – Queensland

5-year outlook

Queensland

● Unresolved issues

Assessed

System strength

Frequency and inertia

Voltage control

Operability

Resource adequacy

To be assessed

System restoration

Transient and oscillatory stability

Context

Queensland has experienced a record minimum 30-minute operational demand of 2,790 MW (31 August 2025 13:00), this contrasts with a maximum demand of 11,170 MW (22 January 2025). The 2025 ESOO anticipates operational demand will continue to fall by 250 MW a year through to 2030 when coal generation exits and network investments are planned to occur. Despite the development of active management capability for PV systems greater than 10kVA, the region has a growing shortfall in capability to increase operational demand to thresholds that may be required under onerous system conditions.

Impacts

As minimum system load (MSL) continues to decline, technical challenges begin to emerge. AEMO determines MSL thresholds according to the level of demand needed to operate the minimum combination of synchronous generating units required to maintain security[A]. Under rare, but plausible, onerous conditions, demand in Queensland needs to be maintained at or above 3,235 MW (reducing to 3,087 MW with new utility-scale BESS) to ensure adequate provision of essential services.

Current options to manage MSL2 conditions in Queensland, include recalling network outages, decommitting synchronous units, directing pumping loads, or instructing DNSPs to curtail embedded generators including non-scheduled PV (PVNSG) and other non-scheduled generators (ONSG).

If an MSL3 condition is forecast, AEMO instructs NSPs to maintain operational demand above the required threshold. This would typically require Energy Queensland to undertake actions to increase operational demand. Present capabilities include:

- Active management for PV ≥10kVA via generation signalling devices (GSDs).

MSL Outlook *Refer to TPSS Part C and Appendix 3*[B]

Under typical system normal conditions: if coal generation exits and network investments proposed across the NEM proceed, all forecast MSL2 and MSL3 over the outlook horizon are projected to be resolved via AEMO actions and export into other regions. Any delays in planned transition activities (such as to prepare for potential coal decommitment and Gladstone exit) may increase the number of events requiring operational management, this may occur as early as 2027-28; however, coordination of large-scale storage and CER may help to decrease the need for intervention in the outlook period.

Rare, but plausible, onerous system conditions are modelled assuming 1) Queensland operating as an island, 2) typical large synchronous units operating at minimum levels, 3) one Wivenhoe pumping load unavailable, and 4) one significant lower contingency FCAS provider unavailable. The modelling also considers an additional 2.3GW/5.4GWh of committed and commissioning utility BESS arriving before Winter 2026

Under these rare, but plausible onerous system conditions: there is a present and growing shortfall in the ability for DNSPs to increase operational demand to the minimum thresholds. To maintain system security in such conditions without shedding reverse flowing feeders, it is estimated that an additional ~515 MW is required by Winter 2026 (beyond existing capability). Analysis indicates that in the absence of further actions (see below), even if all reverse flowing feeders are shed, this may be insufficient to restore system security and Queensland could be operating insecure for periods with escalated risks of black system.

Actions

The development of activities to ensure a smooth transition and provision of essential services in Queensland is underway, as detailed overleaf. Key recommended actions are detailed below:

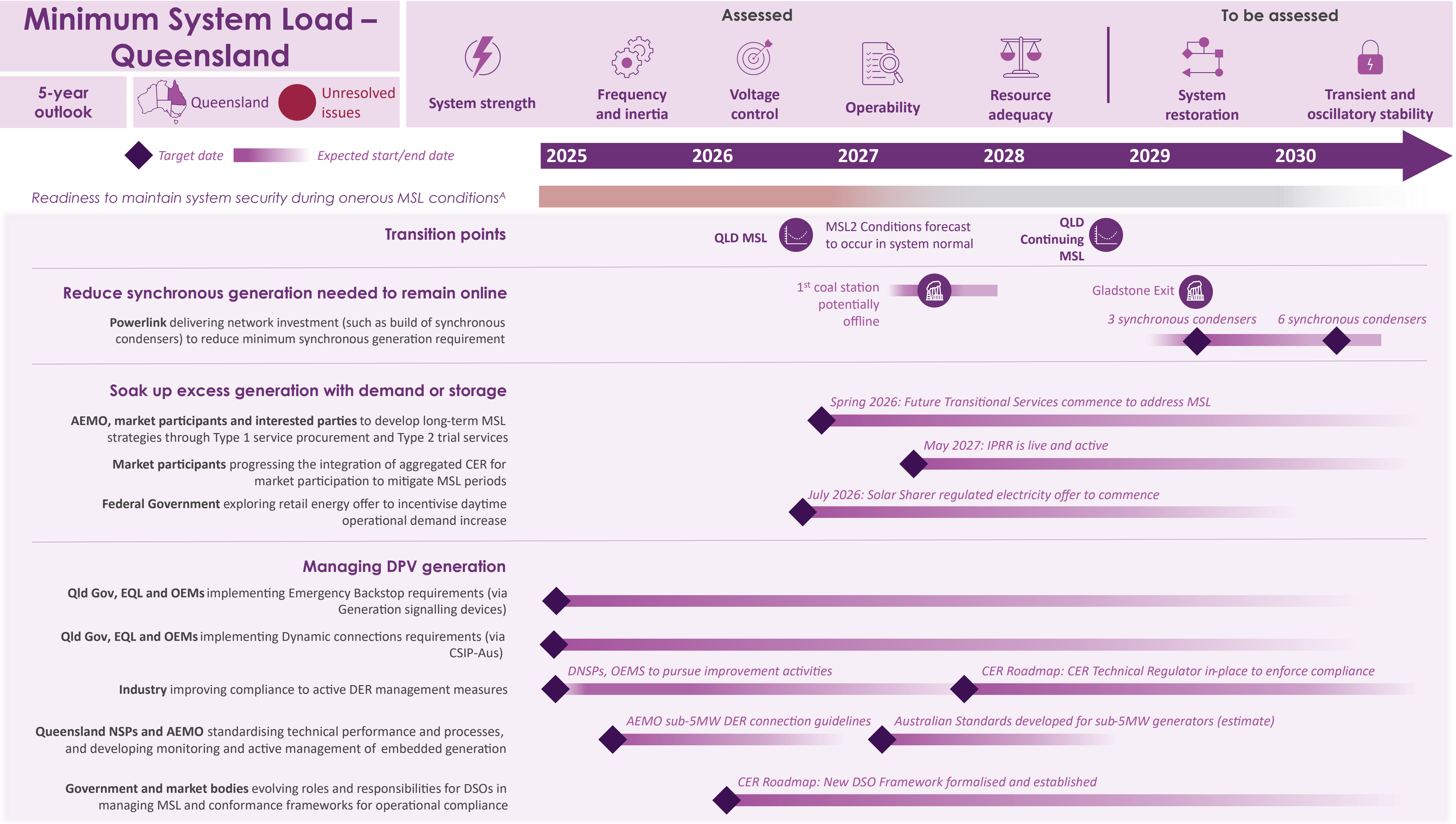
- **Queensland Government and NSPs** to urgently consider expanding the coverage of active management capabilities to PV installations <10kVA, continue urgent measures to improve compliance with existing mechanisms, and consider frameworks to conduct regular at-scale testing. Additionally, consider other innovative capabilities to expand MSL3 actions to increase operational demand under rare but plausible onerous system conditions as soon as possible to avoid reliance on reverse feeder shedding.
- **NEM NSPs and industry** to target delivery, on time and in full, of planned investments for system security services and pathways to reduce generator unit minimum operating levels to reduce the likelihood of future MSL3 events.
- **AEMO** is seeking expressions of interest to supply either Type 1 Transitional Services to address immediate MSL conditions or Type 2 Trial Services for novel solutions beyond 2028. Interested parties to consider opportunities to deliver these services for MSL[C].
- **Industry and government** to consider further incentives for coordination of large-scale storage and CER (including residential batteries and EV loads), particularly to support low demand periods.

A. This includes: MSL3: immediate action needed to increase demand; MSL2: system is one credible load contingency away from MSL3; and MSL1: system is two credible load contingencies away from MSL3. Further details on the strategies for managing MSL into the future can be found in Section 9.

B. Refer to Part C Section 9.1 and Appendix A3 for further details.

C. For more information, see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning

Minimum System Load – Queensland



Readiness to maintain system security during onerous MSL conditions[A]

Transition points

Reduce synchronous generation needed to remain online

Powerlink delivering network investment (such as build of synchronous condensers) to reduce minimum synchronous generation requirement

Soak up excess generation with demand or storage

AEMO, market participants and interested parties to develop long-term MSL strategies through Type 1 service procurement and Type 2 trial services

Spring 2026: Future Transitional Services commence to address MSL

Market participants progressing the integration of aggregated CER for market participation to mitigate MSL periods

May 2027: IPRR is live and active

Federal Government exploring retail energy offer to incentivise daytime operational demand increase

July 2026: Solar Sharer regulated electricity offer to commence

Managing DPV generation

Qld Gov, EQL and OEMs implementing Emergency Backstop requirements (via Generation signalling devices)

Qld Gov, EQL and OEMs implementing Dynamic connections requirements (via CSIP-Aus)

Industry improving compliance to active DER management measures

DNSPs, OEMS to pursue improvement activities

CER Roadmap: CER Technical Regulator in-place to enforce compliance

Queensland NSPs and AEMO standardising technical performance and processes, and developing monitoring and active management of embedded generation

AEMO sub-5MW DER connection guidelines

Australian Standards developed for sub-5MW generators (estimate)

Government and market bodies evolving roles and responsibilities for DSOs in managing MSL and conformance frameworks for operational compliance

CER Roadmap: New DSO Framework formalised and established

A. Beyond 2027-28, there is a high level of uncertainty in the forecast of both MSL thresholds and capabilities of MSL actions available to NSPs.

1st coal station potentially offline

2027-28 | Queensland | ● On track

◆ Action required

Assessed: System strength ◆ | Frequency and inertia ◆ | Voltage control | Resource adequacy

To be assessed: Operability | Transient and oscillatory stability | System restoration

Context

While the recent Queensland Energy Roadmap has suggested actions will be taken to ensure its coal fleet remains available if required for reliability and security, economic factors (including in other regions) could start triggering coal to be offline in Queensland earlier. Per the 2025 AEMO Thermal Audit[A], Queensland coal plants have not and are not planning to investigate two-shifting, suggesting that economically decommitted plant could be offline for longer periods, such as weeks or months.

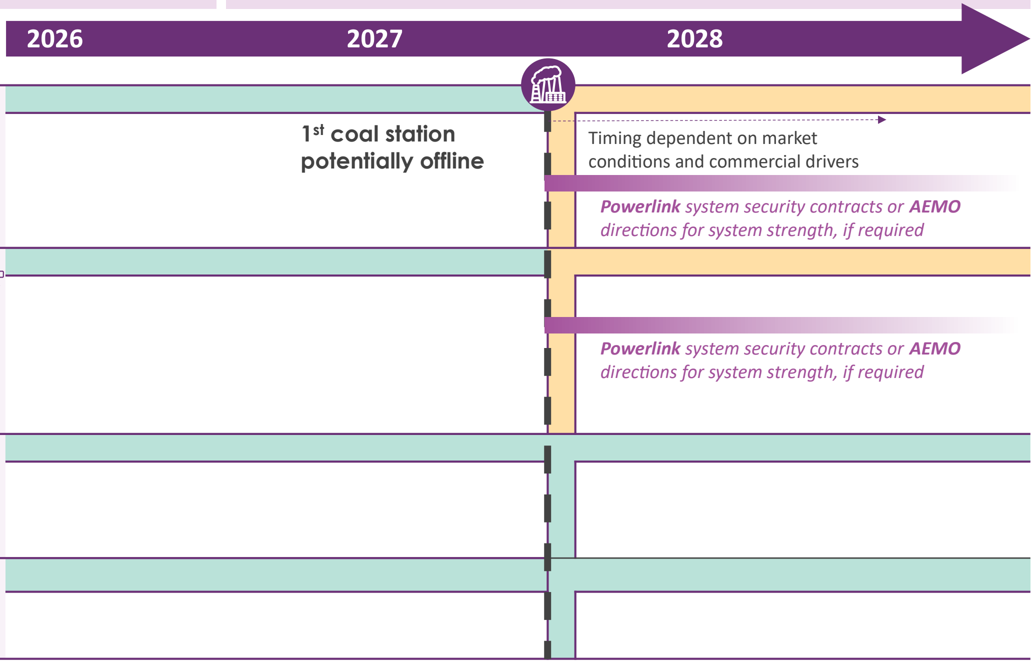
Impacts

Market dispatch outcomes may not meet minimum fault level requirements under system normal conditions. Nor may they meet inertia requirements for an islanded system. The operational impacts of this are expected to be minor because there are sufficient alternative resources available in Queensland to meet operational requirements.

Actions

- **AEMO** is actively monitoring forecast market outcomes in Queensland to ensure sufficient resources are available and remain online for system security. Where market outcomes may result in a deficit, **AEMO** will activate **Powerlink** system security contracts, where available, or issue directions to bring synchronous units online to support system strength and inertia.
- **Powerlink** is progressing inertia remediation activities in parallel with its system strength Regulatory Investment Test for Transmission (RIT-T)[B]. **AEMO** will continue to work with **Powerlink** to track the progress of these measures.

◆ *Target date* ▬ *Estimated start/end date*



System strength

Market dispatch outcomes in Queensland may not meet minimum fault level requirements at times due to reduced export requirements into New South Wales. **Powerlink** is progressing delivery of system strength solutions under their RIT-T[A]. These are not expected to be operational in time, if a coal station were potentially to be offline in 2027-28, which would necessitate **AEMO** to use contracts or directions to bring additional units online under these conditions.

Frequency and inertia

For this potential transition point, market modelling outcomes project an inertia deficit for 2027-28 where the available inertia in Queensland is below its secure operating level requirement of 13,700MWs for islanded operation. This poses a risk to power system operation, as Queensland is sufficiently at-risk of islanding until the delivery of additional interconnectors, such as the actionable QNI Connect project. However, in operational timeframes, directions will only be required if the amount of inertia and FCAS available is found to lead to unsatisfactory frequency or stability outcomes.

Voltage control

Currently it is expected that voltage control can be managed under system normal conditions, credible contingency and outage conditions for this potential transition point.

Resource adequacy – thermal limits

Currently it is expected that this potential transition point does not result in new thermal limits challenges.

A. See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/2025-thermal-audit.pdf

B. See https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf

Gladstone exit

Q1 2029

Queensland

On track

◆ Action required

Assessed

- System strength ◆
- Frequency and inertia ◆
- Voltage control ◆
- Resource adequacy ◆

To be assessed

- Operability
- Transient and oscillatory stability
- System restoration

Context

AEMO has received advice from Rio Tinto[A] on the potential for market exit of Gladstone Power Station, Queensland's largest coal plant, in March 2029. Gladstone Power Station's exit has localised implications for reliable supply of key load centres and system security in Central Queensland.

Impacts

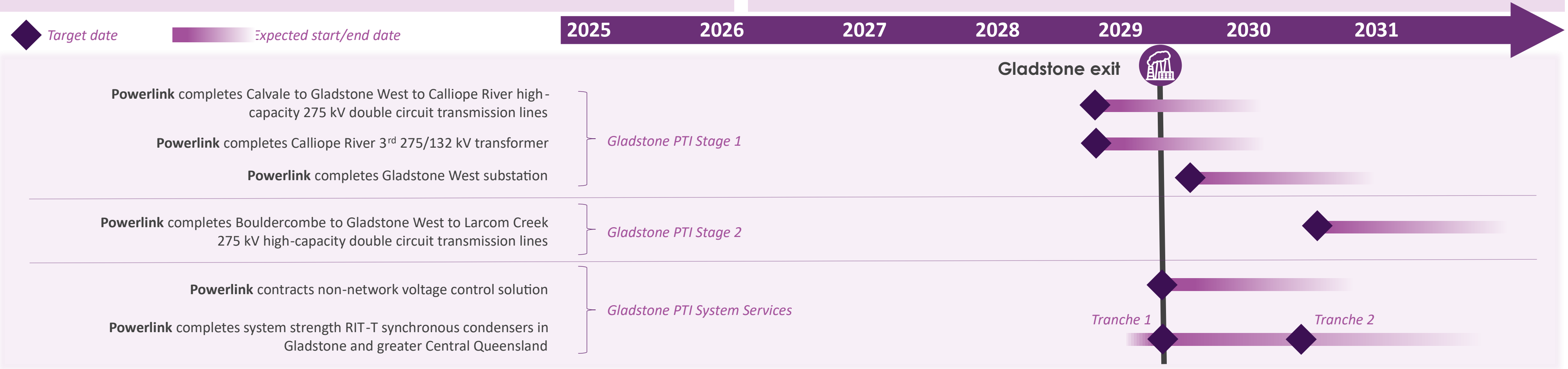
AEMO and **Powerlink** have been actively planning for the eventuation of this transition point for years, including the 2020 ISP identification of the Gladstone Grid Reinforcement project. Transition planning studies have shown that without on time and in full delivery of planned investments, the exit of Gladstone Power Station in March 2029 would negatively impact reliability and system security in the Gladstone region of Central Queensland.

To address these risks, **Powerlink** is progressing the Gladstone PTI project[B] and delivery of system strength solutions under their RIT-T[C], which together provide improvements to system strength, thermal limits, voltage control, and inertia. These projects are on track to derisk this transition point, provided **Powerlink** delivers these targeted measures on time and in full prior to the exit of Gladstone Power Station.

Actions

Readiness for this transition point is contingent upon delivery of key infrastructure projects ahead of Gladstone Power Station exit. Preparatory studies will continue to be conducted to assess readiness.

- **Powerlink** to target delivery of all stages of the Gladstone PTI project[B] and RIT-T[C] for system strength synchronous condensers (tranche 1) in the Gladstone area and Central Queensland on time and in full.
- **AEMO** to conduct transition planning assessments, including operability assessments, as the transition point gets closer to Horizon 1 (0 – 2 year operational timeframe).
- **AEMO** to conduct system restoration planning analyses with Powerlink in preparation for the 2027 SRAS procurement round.
- **AEMO** to complete preparatory work on small signal stability to facilitate analysis that incorporates system changes associated with the exit and decommitment of synchronous generators. This effort aims to ensure that stabilising devices effectively dampen the inter-area modes. This work is expected to be completed in 2026.
- Should insufficient assets be operational ahead of this potential transition point, **AEMO** will enable **Powerlink** system security contracts, or issue directions, to manage system security as needed.



Gladstone PTI Stage 1

- **Powerlink** completes Calvale to Gladstone West to Calliope River high-capacity 275 kV double circuit transmission lines
- **Powerlink** completes Calliope River 3rd 275/132 kV transformer
- **Powerlink** completes Gladstone West substation

Gladstone PTI Stage 2

- **Powerlink** completes Bouldercombe to Gladstone West to Larcom Creek 275 kV high-capacity double circuit transmission lines

Gladstone PTI System Services

- **Powerlink** contracts non-network voltage control solution
- **Powerlink** completes system strength RIT-T synchronous condensers in Gladstone and greater Central Queensland

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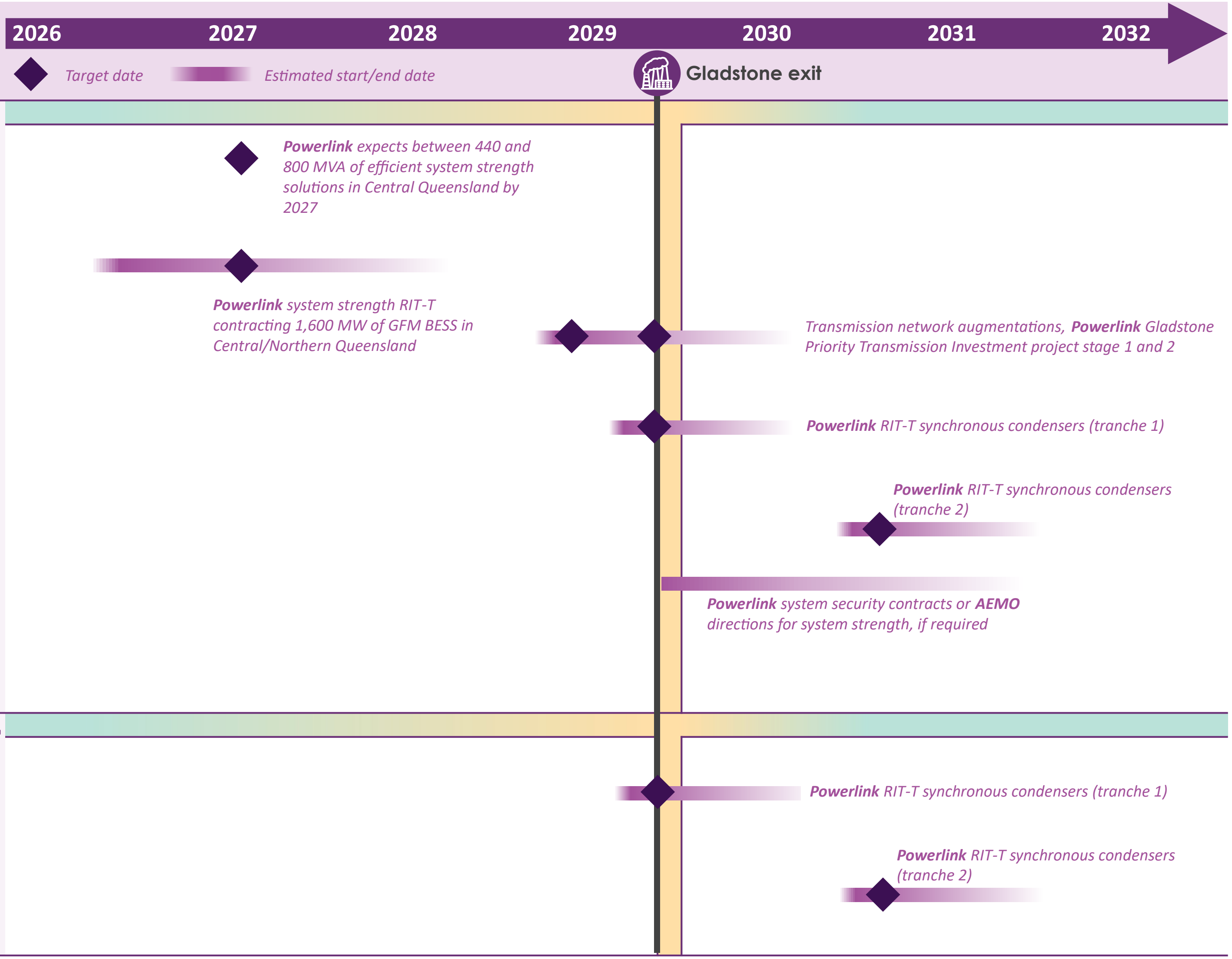
A. See https://www.riotinto.com/en/news/releases/2025/notification-of-potential-retirement-of-gladstone-power-station

B. See https://hdp-au-prod-app-pq-projects-files.s3.ap-southeast-2.amazonaws.com/8917/5014/1929/Gladstone_PTI_Final_Assessment_Report_web.pdf

C. See https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf

Gladstone exit



2026 2027 2028 2029 2030 2031 2032

◆ *Target date*   *Estimated start/end date*

Gladstone exit

__Powerlink__ expects between 440 and 800 MVA of efficient system strength solutions in Central Queensland by 2027

__Powerlink__ system strength RIT-T contracting 1,600 MW of GFM BESS in Central/Northern Queensland

Transmission network augmentations, __Powerlink__ Gladstone Priority Transmission Investment project stage 1 and 2

__Powerlink__ RIT-T synchronous condensers (tranche 1)

__Powerlink__ RIT-T synchronous condensers (tranche 2)

__Powerlink__ system security contracts or __AEMO__ directions for system strength, if required

__Powerlink__ RIT-T synchronous condensers (tranche 1)

__Powerlink__ RIT-T synchronous condensers (tranche 2)

System strength

Powerlink plans to address the system strength reductions associated with the announced exit of Gladstone Power Station with tranche 1 synchronous condensers and network augmentations, which are planned to be complete in March 2029[A]. This planned completion coincides with the expected timing of this transition point, meaning delayed delivery would result in system strength deficits.

On time and in full delivery of transmission augmentations and tranche 1 synchronous condensers by **Powerlink**[A,B] is critical to ensuring minimum fault levels can be maintained without AEMO interventions.

To meet stable voltage waveform requirements, **Powerlink** is progressing procurement of new GFM BESS or other localised solutions as part of their system strength RIT-T, which is to be delivered by 2027. **Powerlink** will monitor and address requirements beyond 2027 as they become clear.

At times, less than 7 large synchronous units may be dispatched by the market in Central Queensland. Without on time and in full delivery of new assets, **AEMO** will need to enable **Powerlink** system security contracts, or issue directions, at these times to bring on hydro or gas generation online to meet system strength requirements.

Frequency and inertia

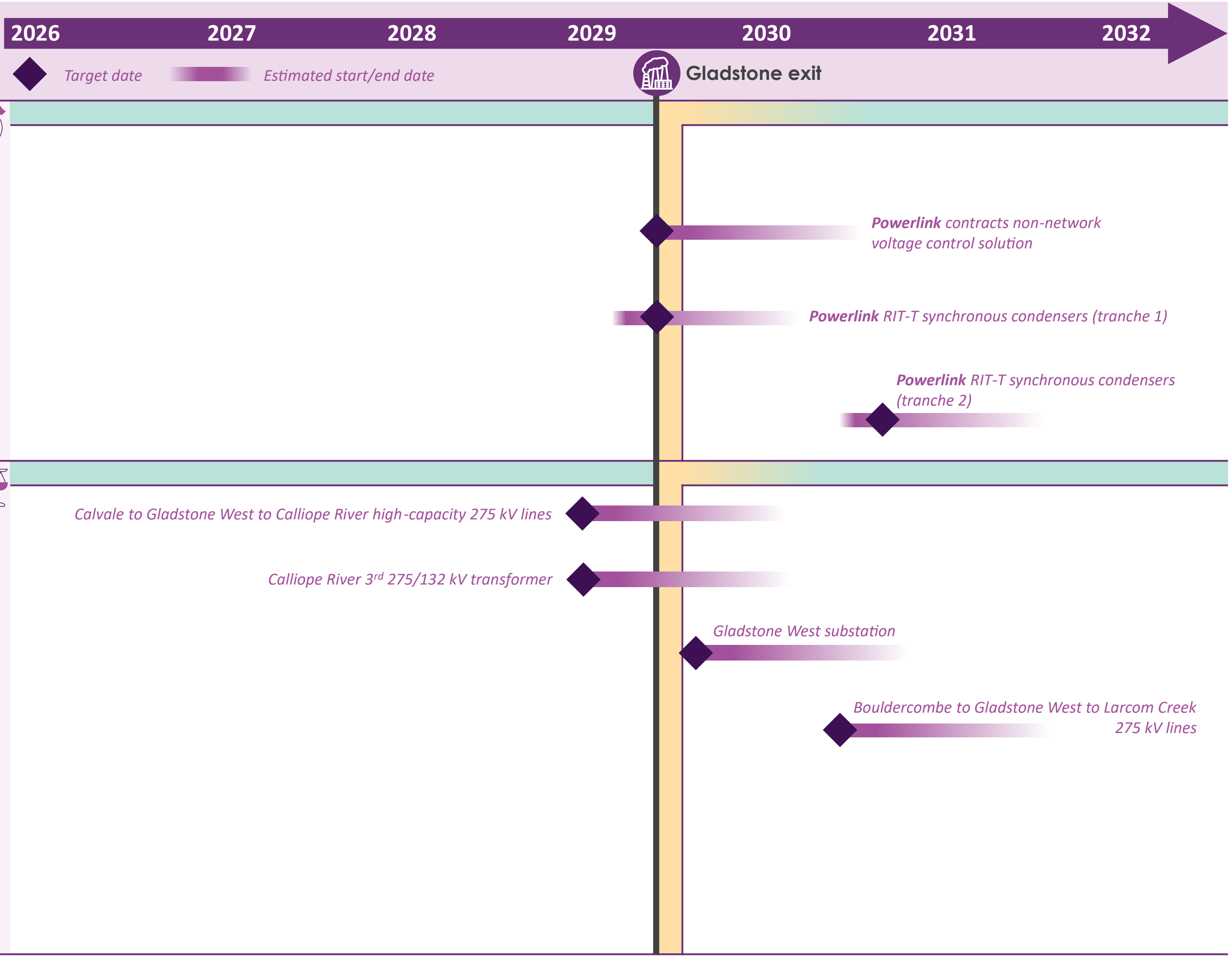
Without delivery of synchronous condensers prior to Gladstone Power Station exit, an inertia deficit is expected in the Gladstone area from March 2029. Risk to inertia is driven by potential for project delays.

Powerlink plans to address this inertia deficit with delivery of tranche 1 synchronous condensers in March 2029[A]. On time and in full delivery by **Powerlink** is critical to ensuring inertia requirements can be maintained without AEMO interventions.

A. See https://hdp-au-prod-app-pq-projects-files.s3.ap-southeast-2.amazonaws.com/8917/5014/1929/Gladstone_PTI_Final_Assessment_Report_web.pdf

B. See https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf

Gladstone exit



Voltage control

Without delivery of synchronous condensers and network upgrades prior to Gladstone Power Station exit, voltage control capabilities in the Gladstone area will be insufficient.

Powerlink's Gladstone PTI project[A] is designed to address voltage control deficits through new reactive non-network contracting, and tranche 1 synchronous condensers from their RIT-T for system strength[B]. Delivery of solutions to address voltage control is planned by March 2029.

Project delays risk voltage control deficits if Gladstone PS exits before voltage control remediation is delivered. **Powerlink** to target delivery of the Gladstone PTI project[A] on time and in full prior to Gladstone PS exit.

Resource adequacy - thermal limits and reliability

Without delivery of key actionable transmission augmentations prior to this transition point, the October 2025 Update to the 2025 ESOO forecast that reliability risks in Queensland exceed the Reliability Standard from 2029-30 when the Gladstone Power Station is advised to potentially close[C]. This would likely arise from curtailment of generation to the west and north of the Gladstone area during system normal conditions due to transmission constraints caused by existing Gladstone area transmission thermal limitations and transfer capacity.

Powerlink's Gladstone PTI project[A,B] is projected to alleviate these constraints and enable reliability to be within the Reliability Standard, contingent upon commissioning prior to Gladstone PS exit. In the interim between Gladstone PS exit and delivery of the Bouldercombe-Larcom 275kV lines (now scheduled mid-2030), transmission constraints will heighten the importance of Callide area generation in meeting the Reliability Standard until 2030. **Market** delivery of committed and anticipated generation projects in the Gladstone area before March 2029 is expected to further support reliability.

Powerlink to target delivery of the Gladstone PTI project network upgrades and synchronous condensers on time and in full ahead of Gladstone PS exit.

A. See https://hdp-au-prod-app-pq-projects-files.s3.ap-southeast-2.amazonaws.com/8917/5014/1929/Gladstone_PTI_Final_Assessment_Report_web.pdf

B. See https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf

C. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/october-2025-update-to-the-2025-esoo.pdf

South Australia

Context

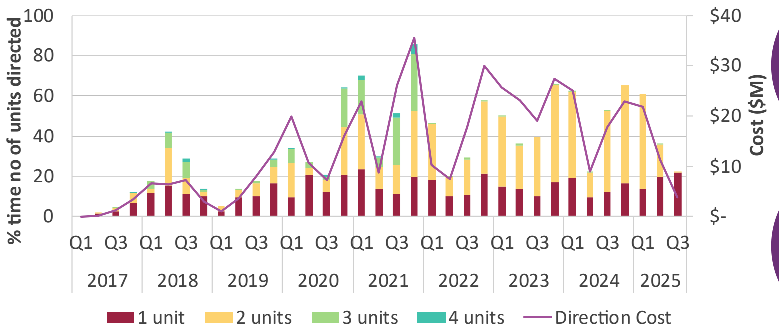
The South Australian power system is world-leading in renewable energy generation, including high levels of rooftop solar. System security in South Australia is supported by synchronous condensers, neighbouring regions via interconnectors and a small number of synchronous generators. As renewable energy contributions continue to increase, work must continue to ensure power system security is maintained.

Over the past year, AEMO and ElectraNet have navigated the transition point of reducing the minimum synchronous generator requirement from two to one when system conditions allow. This has helped to lower the region's minimum stable operating load. However, minimum system load (MSL) conditions are expected to continue as demand decreases. MSL is managed through contracts, directions, and SAPN's development of operational demand increase capabilities, including active DER management through CSIP-Aus.

Project EnergyConnect will reduce the risk of South Australia islanding and help reduce reliance on fossil fuelled generation within the state for system security. It will contribute to enabling the reduction of the minimum synchronous generator requirement from one to zero synchronous generators.

The 800MW Torrens Island B gas station (TIPSB) is scheduled to exit in 2028.

The need to direct gas units for security is expected to reduce



Directions cost $74m in 12 months to Q3 2025 (excluding indirect costs)

Number of synchronous generators directed has reduced from Q3 2025

Timeline | **Now** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035**

○ Transition Point
○ Monitored potential Transition Point
⚠ NSCAS Gap
● Complete/on track
● Moderate readiness
● Unresolved issues

● SA one minimum synchronous generator

● SA MSL

● SA zero minimum synchronous generators

○ Torrens Island B Exit

Security challenges

South Australia is projected to experience increasing incidences of MSL conditions during system normal conditions, requiring AEMO action to manage. AEMO expects to have sufficient tools and interventions to manage MSL conditions through the 5-year outlook horizon, but on time and in full delivery of planned system security investments remain critical. Enhanced flexibility of CER and storage are also critical to manage MSL during peak DPV times to minimise adverse impacts on consumers.

As South Australia is moving towards reduction in synchronous generator requirements, TIPS B exit will largely impact resource adequacy rather than system security. However, there may be flow on effects to this for system restoration, which relies on the availability of firm generation.

Actions

Continued efforts are needed across multiple parties to support readiness for MSL conditions, including continued roll-out of emergency backstop and flexible export capabilities.

- The delivery of Project EnergyConnect Stage 2 is needed to support reliability, South Australian security under reduced synchronous generation conditions and minimum system load management.
- **AEMO** is developing a new Transitional Service to encourage more market responses for MSL management services, particularly critical in South Australia.
- **AEMO** and **ElectraNet** are undertaking programs of work to support South Australia operation with zero synchronous generators online.
- **AEMO** to monitor impacts of Torrens Island B exit on system restoration as a potential future transition point.

South Australia

REGIONAL DEVELOPMENTS	Now	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Synchronous generator capacity change *Annual capacity changes (MW)*			-200	-338	-600	-250					-84
Committed and anticipated IBR *Annual capacity changes (MW)*		+364		+623	+300	*Future project details periodically evaluated in NEM generation information processes*					
IBR forecasts (*Sets efficient Sys. Strength level*) *Annual capacity changes (MW)*		+514		+3,594	+459	+155					

Transmission augmentation

● Committed/anticipated

● RIT-T in progress/actionable

PEC 2

Northern Transmission Project (formerly Mid North SA REZ project)

ElectraNet system strength RIT-T – at Project Assessment Draft Report (PADR) Stage[A]

PADR conclusion: Remediate system strength by upgrading new synchronous gas generators with clutches to enable synchronous co ndenser mode

Transition Points

○ **Transition Point**

○ Potential Transition Point being monitored

SA one minimum synchronous generator

SA MSL

SA zero minimum synchronous generators

Torrens Island B Exit

AEMO'S CURRENT OUTLOOK	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Assessment horizon	***NSCAS assessment*** *(See Appendix 2)*					***Long term assessment***				

System strength – *nodal assessment* (minimum fault current in MVA)

Long-term, system strength requirements are managed by ElectraNet through the RIT-T framework.

ElectraNet's Meeting System Strength Requirements RIT-T. ElectraNet RIT-T is up to the Project Assessment Draft Report phase (released June 2025). The currently preferred option is to contract with future non-network proponents to add mechanical clutches to turbines to provide synchronous condenser capability.

Inertia (MWs)

Low long-term risk due to existing synchronous condensers and IBR participation in frequency market providing sufficient inertia and frequency support.

Thermal and voltage

⚠ Existing voltage control gap until ElectraNet complete voltage control RIT-T Oct 2027.

AEMO and ElectraNet monitoring thermal loading and voltage control gaps over the transition.

------ Requirements ▬ Available level ▬ Deficit ⚠ NSCAS Gap

A. See https://electranet.com.au/wp-content/uploads/2025/04/RIT-T-PADR_Meeting-System-Strength-in-SA.pdf

One minimum synchronous generator in SA

Q3 2025

South Australia

Complete

Assessed

System strength

Frequency and inertia

Voltage control

Transient and oscillatory stability

System restoration

Operability

Resource adequacy

Context

AEMO and **ElectraNet** successfully reduced the minimum synchronous generator requirement in South Australia from 2 to 1 on 2 September 2025[A].

Impacts

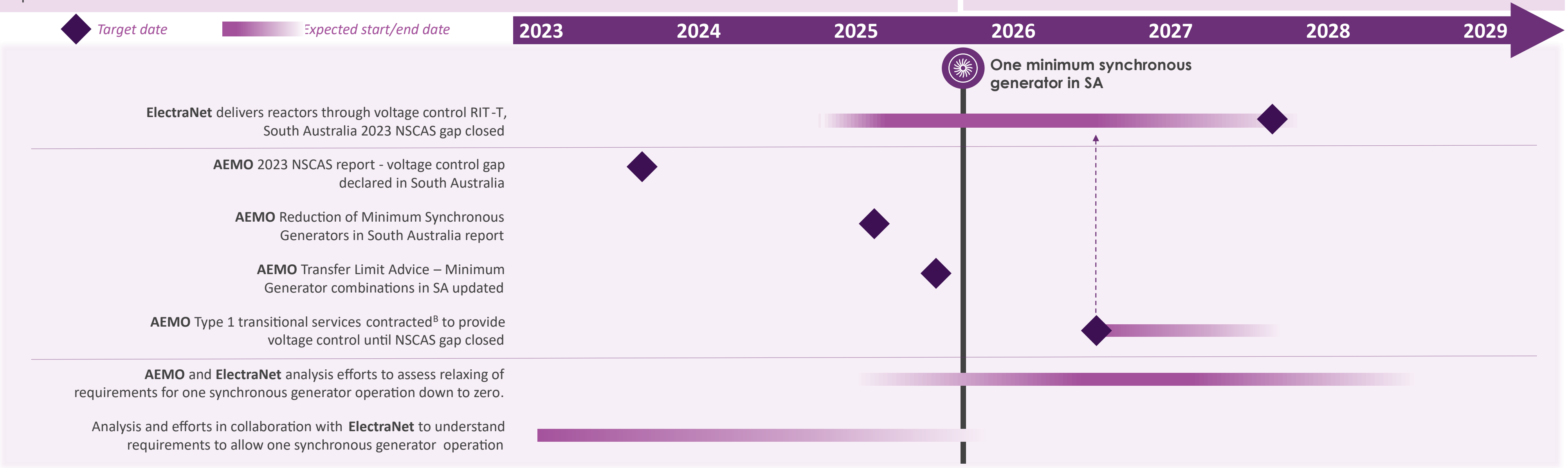
The successful navigation of this transition point reduces renewable curtailment in South Australia and the cost of directions.

Under certain power system conditions – such as low operational demand, risk of separation, lack of available fast start generation or other credible contingencies – two synchronous generators are still required to be online to manage ramping requirements and enable the system to be resecured within 30 minutes.

Additional efforts are required to relax conditions still requiring two synchronous generator operation, particularly the delivery of **ElectraNet**'s voltage control RIT-T. Delays to delivery will continue restrictions that further require two synchronous generator operation.

Actions

- **AEMO** thoroughly studied this transition point with **ElectraNet** and other stakeholders.
- **AEMO's** plan to use Type 1 transitional service contracts[B] to maintain security with only one synchronous generator online, allowing this operation as often as possible until the voltage control NSCAS gap is closed.
- **AEMO** and **ElectraNet** are now progressing efforts to relax requirements for one synchronous generator operation and have fewer times of two synchronous generator requirements. Removal of operational demand requirements can be completed when **ElectraNet** closes the voltage control NSCAS gap with their RIT-T[C].



ElectraNet delivers reactors through voltage control RIT-T, South Australia 2023 NSCAS gap closed

AEMO 2023 NSCAS report - voltage control gap declared in South Australia

AEMO Reduction of Minimum Synchronous Generators in South Australia report

AEMO Transfer Limit Advice – Minimum Generator combinations in SA updated

AEMO Type 1 transitional services contracted[B] to provide voltage control until NSCAS gap closed

AEMO and **ElectraNet** analysis efforts to assess relaxing of requirements for one synchronous generator operation down to zero.

Analysis and efforts in collaboration with **ElectraNet** to understand requirements to allow one synchronous generator operation

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A. See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/related-resources/reduction-of-minimum-synchronous-generators-in-south-australia.pdf

B. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/south-australian-grid-reference-transitional-service

C. See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nsp_consultations/2022/pscr-ec11645-transmission-network-voltage-control---summary.pdf

Minimum System Load – South Australia

5-year outlook

South Australia ● Moderate Readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Operability
- Resource adequacy

To be assessed

- System restoration
- Transient and oscillatory stability

Context

South Australia has experienced a record minimum 30-minute operational demand of -205 MW (19 October 2024 13:00), this contrasts with a maximum demand of 3,399 MW (31 January 2011). The 2025 ESOO anticipates that operational demand will continue to fall by 100MW a year through to 2028. South Australia has progressed activities to build active management capability for DER since 2020 and has utilised this capability during system events in 2021, 2022 and 2024. Minimum system load (MSL) risks persist, and there may be increasing risks of MSL events coincident with neighbouring regions.

Impacts

As MSL continues to decline, technical challenges begin to emerge. AEMO determines MSL thresholds according to the level of demand needed to operate the minimum combination of synchronous generating units required to maintain security[A]. Under rare but plausible onerous conditions, demand in SA needs to be maintained at or above 270 MW (reducing to 203 MW with new utility-scale BESS in spring 2026) to ensure provision of essential system services.

If MSL2 or MSL3 conditions are forecast, AEMO takes actions to clear the condition. Current AEMO actions in South Australia include recalling outages, decommitting synchronous units and directing resecure reserve.

If MSL3 conditions persist following AEMO actions, or MSL3 is forecast without sufficient lead time for AEMO actions to take effect and clear the condition, AEMO instructs NSPs to maintain operational demand above the required threshold to maintain system security. Present capabilities in South Australia include:

- Curtailing embedded generators including non-scheduled PV (PVNSG)
- Active DER management via Relevant Agents (RA)
- Active DER management via Common Smart Inverter Protocol – Australia (CSIP-AUS)
- DER management via static export limits
- Emergency voltage management (EVM)[B], the deliberate increase of distribution voltages to disconnect distributed PV.

MSL Outlook *Refer to TPSS Part C and Appendix 3[C]*

Under typical system normal conditions: if network investments to reduce minimum synchronous generator units proposed across the NEM proceed as planned, all forecast MSL3 in SA over the outlook horizon are projected to be resolvable via AEMO actions and export into other regions. Any delays in planned transition activities (such as completion of Project EnergyConnect Stage 2 and the reduction of minimum synchronous generator units) may increase the number of events requiring operational management, this may occur as early as 2027-28; coordination of large-scale storage and CER may help to decrease the need for intervention in the outlook period.

Rare, but plausible, onerous system conditions are modelled assuming 1) South Australia operating as an island with no energy flows in or out of the region, 2) typical large synchronous generator units operating at minimum levels, 3) one significant lower contingency FCAS provider unavailable. The modelling also considers BESS installed in 2025 (Blyth, Mannum) plus an additional 0.4GW/0.8GWh of utility-scale BESS installed in 2026.

Under these rare, but plausible, onerous system condition: it is projected that there will be sufficient operational demand increase services available in South Australia to manage both typical and onerous conditions, without the need to shed reverse flowing feeders. Under some onerous MSL3 conditions it may be necessary for SAPN to enact almost all mechanisms available.

Actions

The development of activities to ensure a smooth transition and provision of essential services in South Australia is underway, as detailed overleaf. Key recommended actions are detailed below:

- **NEM NSPs and industry** to target delivery, on time and in full, of planned investments for system security services and pathways to reduce synchronous generator minimum operating levels to reduce the likelihood of future MSL3 events.
- **SA Power Networks** to expand capabilities for active curtailment via CSIP-AUS to 30-200kVA export sites, and to increase speed of active management response.
- **SA Power Networks and technology providers of active curtailment** to continue to support urgent measures to improve compliance with existing mechanisms.
- **Industry and government** to consider further incentives for coordination of storage and CER, particularly to support low demand periods.
- **AEMO** is seeking expressions of interest to supply either Type 1 Transitional Services to address immediate MSL conditions or Type 2 Trial Services for novel solutions beyond 2028. Interested parties to consider opportunities to deliver these services for MSL[D].

[A] This includes: MSL3: immediate action needed to increase demand; MSL2: system is one credible load contingency away from MSL3; and MSL1: system is two credible load contingencies away from MSL3. Further details on the strategies for managing MSL into the future can be found in Section 9.

[C] Refer to Section 9.1 and Appendix A3 for further details.

[B] In relation to EVM, DNSPs need to assess risks, consider pathways (including relevant regulations and legislation), conduct modelling, testing and/or trials as necessary to confirm whether this option is suitable for their network, while ensuring safety and low risk to customer equipment.

[D] For more information, visit https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/minimum-system-load---type-1-transitional-service

Minimum System Load – South Australia

5-year outlook

South Australia ● Moderate Readiness

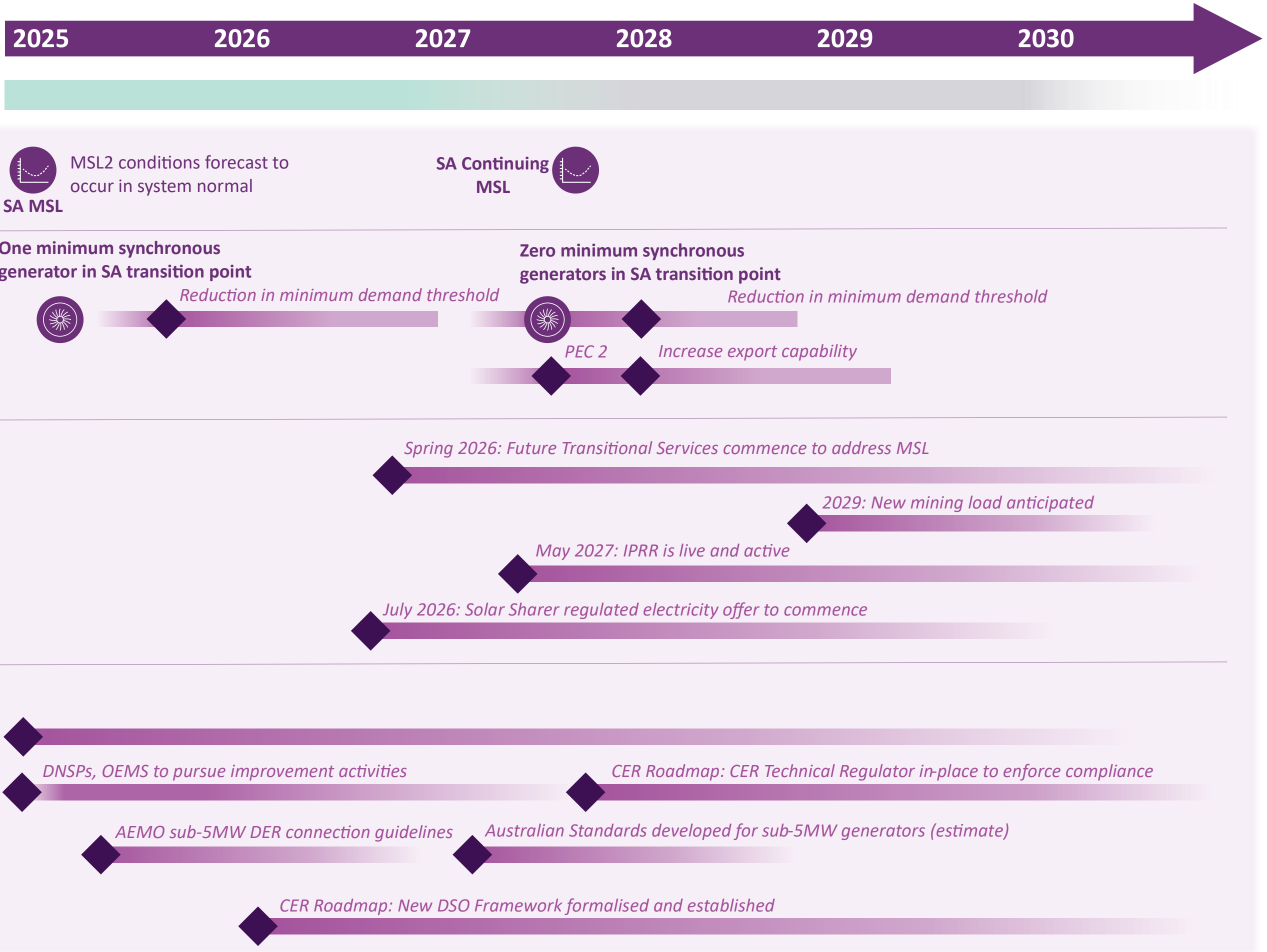
Assessed

- System strength
- Frequency and inertia
- Voltage control
- Operability
- Resource adequacy

To be assessed

- System restoration
- Transient and oscillatory stability

◆ *Target date* ▬ *Expected start/end date*



Readiness to maintain system security during onerous MSL conditions[A]

Transition points

SA MSL: MSL2 conditions forecast to occur in system normal

SA Continuing MSL

Reduce synchronous generation needed to remain online

ElectraNet and AEMO delivering network investment to reduce minimum synchronous generator requirements in SA (reduce from 2 to 1 and 1 to 0)	**One minimum synchronous generator in SA transition point** *Reduction in minimum demand threshold* **Zero minimum synchronous generators in SA transition point** *Reduction in minimum demand threshold*
ElectraNet and Transgrid delivering network investment to increase export (Completion of Project EnergyConnect Stage 2)	*PEC 2* *Increase export capability*

Soak up excess generation with demand or storage

AEMO, market participants and interested parties to develop long-term MSL strategies through Type 1 service procurement and Type 2 trial services	*Spring 2026: Future Transitional Services commence to address MSL*
Industry to invest in new large industrial loads	*2029: New mining load anticipated*
Market participants progressing the integration of aggregated CER for market participation to mitigate MSL periods	*May 2027: IPRR is live and active*
Federal Government exploring retail energy offer to incentivise daytime operational demand increase	*July 2026: Solar Sharer regulated electricity offer to commence*

Managing DPV generation

South Australia Government, SAPN and OEMs implementing Emergency Backstop capability and flexible export limits (FELs)	
Industry improving compliance to active DER management measures	*DNSPs, OEMS to pursue improvement activities* *CER Roadmap: CER Technical Regulator in-place to enforce compliance*
SAPN and AEMO standardising technical performance and processes, and developing monitoring and active management of embedded generation	*AEMO sub-5MW DER connection guidelines* *Australian Standards developed for sub-5MW generators (estimate)*
Government and market bodies evolving roles and responsibilities for DSOs in managing MSL and conformance frameworks for operational compliance	*CER Roadmap: New DSO Framework formalised and established*

A. Beyond 2027-28, there is a high level of uncertainty in the forecast of both MSL thresholds and capabilities of MSL actions available to NSPs.

Zero minimum synchronous generators in SA

Q4 2027

South Australia

Moderate Readiness

Action required ◆

System strength

Assessed

Frequency and inertia

Voltage control

System restoration

Operability

To be assessed

Resource adequacy

Transient and oscillatory stability

Context

AEMO and **ElectraNet** aim to reduce the minimum synchronous generator requirement in South Australia from one to zero within Horizon 1.

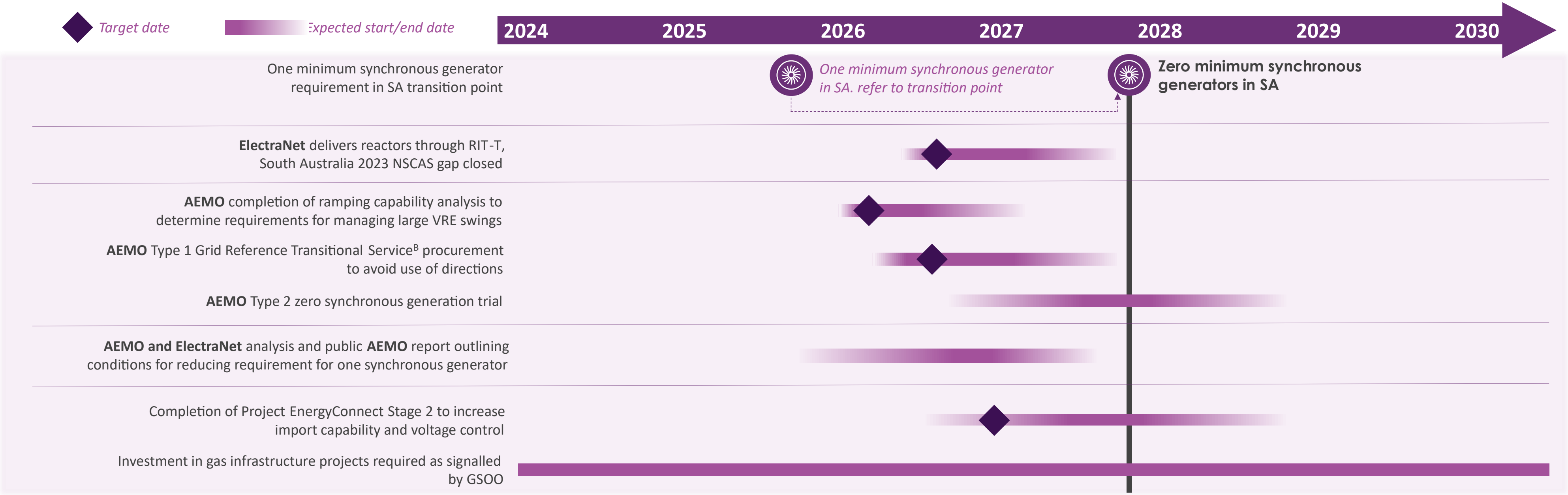
Impacts

To allow operation at times with zero synchronous generation online requires sufficient demonstration and confidence that system security can be maintained during both system intact conditions and during an islanding event[A].

This transition point will support MSL management in South Australia by lowering minimum synchronous generation and allow more generation from CER. It will also further decrease curtailment of renewable generation and the cost of directions.

Actions

- **AEMO** is undertaking a program of work in conjunction with **ElectraNet** to enable South Australia operation with zero synchronous generators online at times when interconnected to the rest of NEM.
- Significant real-world experience is still required to build technical confidence for South Australia operation with zero synchronous generators online, especially to survive a separation event with no synchronous generators. Delivery of Project EnergyConnect Stage 2 would significantly reduce the likelihood of South Australia islanding.



One minimum synchronous generator requirement in SA transition point

ElectraNet delivers reactors through RIT-T, South Australia 2023 NSCAS gap closed

AEMO completion of ramping capability analysis to determine requirements for managing large VRE swings

AEMO Type 1 Grid Reference Transitional Service[B] procurement to avoid use of directions

AEMO Type 2 zero synchronous generation trial

AEMO and ElectraNet analysis and public **AEMO** report outlining conditions for reducing requirement for one synchronous generator

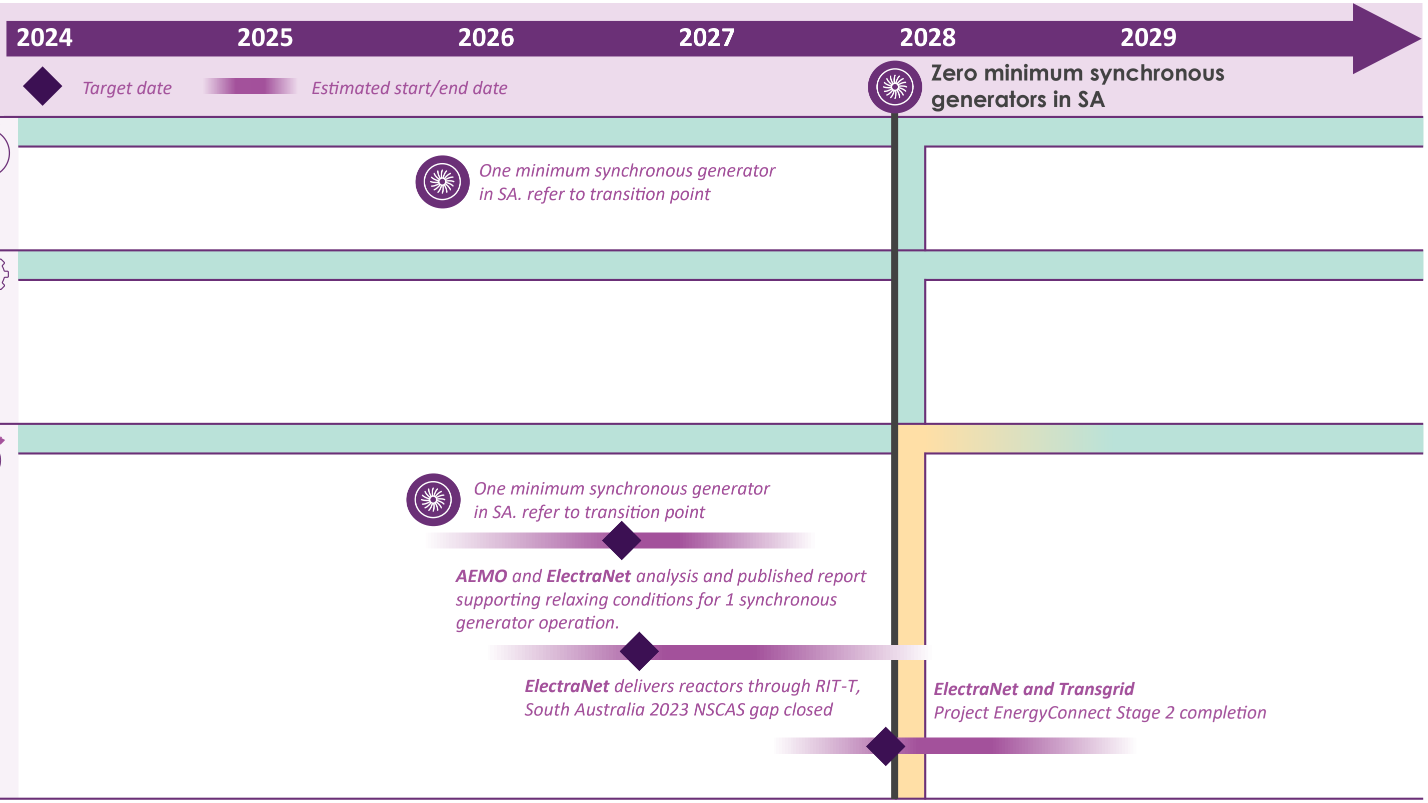
Completion of Project EnergyConnect Stage 2 to increase import capability and voltage control

Investment in gas infrastructure projects required as signalled by GSOO

A. For more information on a preliminary desktop assessment based on simulations conducted by AEMO please see the report: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/related-resources/sa-transition-to-fewer-synch-gen-grid-reference.pdf

B. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/south-australian-grid-reference-transitional-service

Zero minimum synchronous generators in SA



System strength

South Australia's existing four synchronous condensers are expected to be sufficient to meet minimum fault level requirements into the future.

One minimum synchronous generator in SA. refer to transition point

Frequency and inertia

Sufficient frequency support and inertia are expected in South Australia from existing synchronous condensers and growing pool of proponents participating in the FCAS markets.

Voltage control

Per **ElectraNet** limits advice, operation with zero synchronous generators online lowers voltage control availability, particularly during low demand conditions. **ElectraNet's** delivery of reactors in response to the 2023 NSCAS voltage control gap is anticipated to resolve voltage control challenges. Having these reactors operational is a pre -condition to enable operation with no synchronous generating units online[A].

One minimum synchronous generator in SA. refer to transition point

***AEMO** and **ElectraNet** analysis and published report supporting relaxing conditions for 1 synchronous generator operation.*

***ElectraNet** delivers reactors through RIT-T, South Australia 2023 NSCAS gap closed*

***ElectraNet and Transgrid** Project EnergyConnect Stage 2 completion*

[A] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nsp_consultations/2022/pscr-ec11645-transmission-network-voltage-control---summary.pdf

Zero minimum synchronous generators in SA

System restoration

There are negligible risks to system restoration from this transition point. South Australia utilises gas plant for restart that are capable of black start to meet the SRS even when cold due to zero synchronous generator operation.

Operability

Desktop analysis has shown that it may be possible to operate the South Australian power system with no synchronous generating units online[A]. However there has not been real-world demonstration of a power system of South Australia's size operating with no synchronous generation online. To prudently transition to a zero synchronous generating state, **AEMO** is undertaking a program of work in conjunction with **ElectraNet** to build technical confidence that system security can be maintained during both system intact conditions and during an islanding event. Project EnergyConnect Stage 2 will further reduce the likelihood of islanding for South Australia.

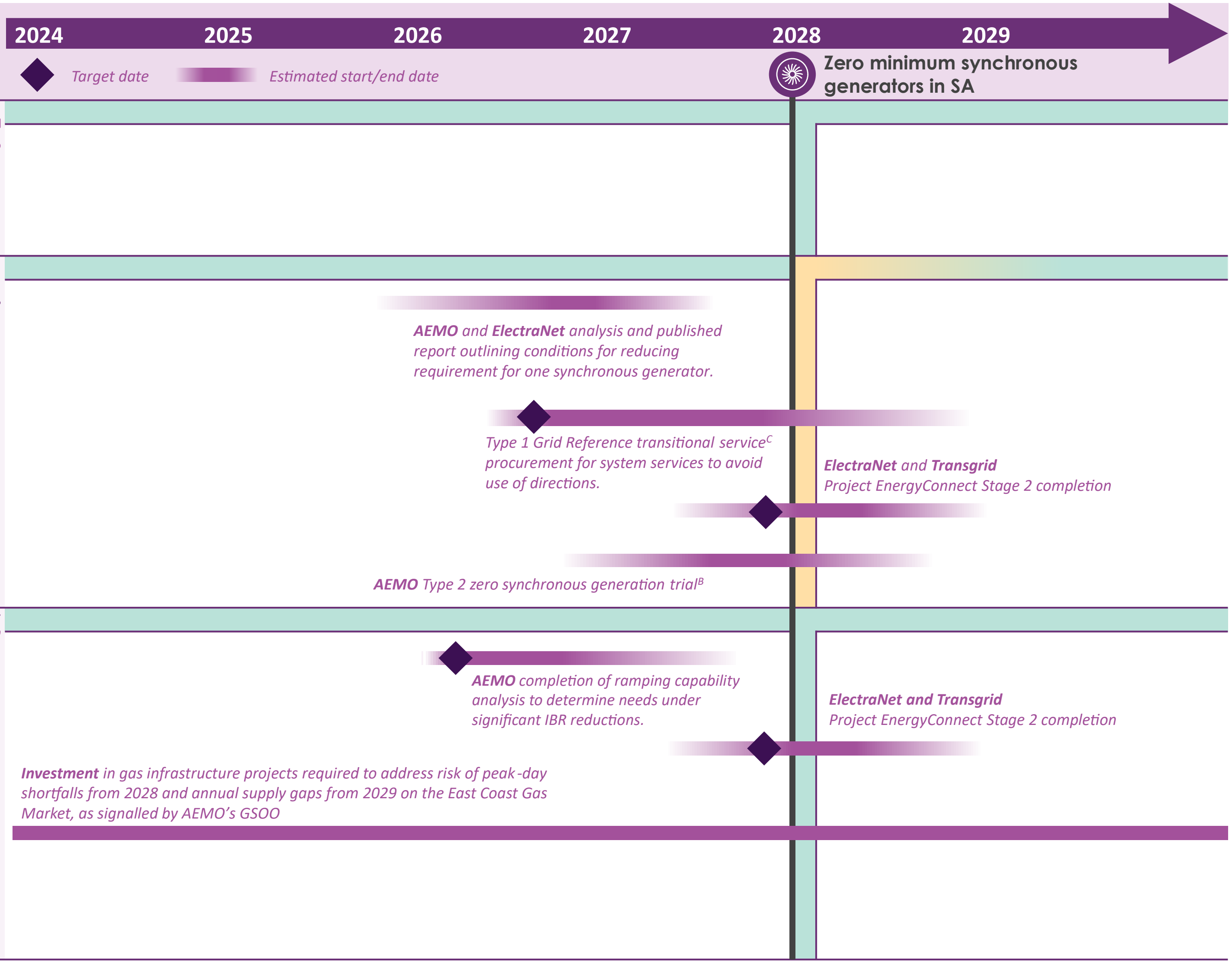
AEMO is undertaking procurement of a Type 2 Transitional Service trial of zero synchronous generation which could further support progression past this transition point[B].

Resource adequacy

Project EnergyConnect Stage 2 completion reduces the risk of South Australia islanding. This allows South Australia to partially rely on interconnector support for ramping, reserve management and resecuring needs.

This transition point poses negligible risks to resource adequacy. It will allow reduced use of gas plant which marginally reduces risks of gas inadequacy.

Despite this transition point, the 2025 GSOO[D] forecasts an increasing risk of peak-day shortfalls from 2028 and annual supply gaps from 2029, impacting GPG availability for reliability, particularly during VRE lulls. GSOO identifies investment opportunities in East Coast Gas Market infrastructure to address projected gas shortfalls and GPG availability.



◆ *Target date* ▬ *Estimated start/end date*

Zero minimum synchronous generators in SA

__AEMO__ and __ElectraNet__ analysis and published report outlining conditions for reducing requirement for one synchronous generator.

Type 1 Grid Reference transitional service[C] procurement for system services to avoid use of directions.

***ElectraNet** and **Transgrid** Project EnergyConnect Stage 2 completion*

***AEMO** Type 2 zero synchronous generation trial[B]*

***AEMO** completion of ramping capability analysis to determine needs under significant IBR reductions.*

***ElectraNet and Transgrid** Project EnergyConnect Stage 2 completion*

***Investment** in gas infrastructure projects required to address risk of peak-day shortfalls from 2028 and annual supply gaps from 2029 on the East Coast Gas Market, as signalled by AEMO's GSOO*

A. See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nsp_consultations/2022/pscr-ec11645-transmission-network-voltage-control---summary.pdf

B. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/zero-synchronous-generation-trial

C. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/south-australian-grid-reference-transitional-service

D. See https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo

Tasmania

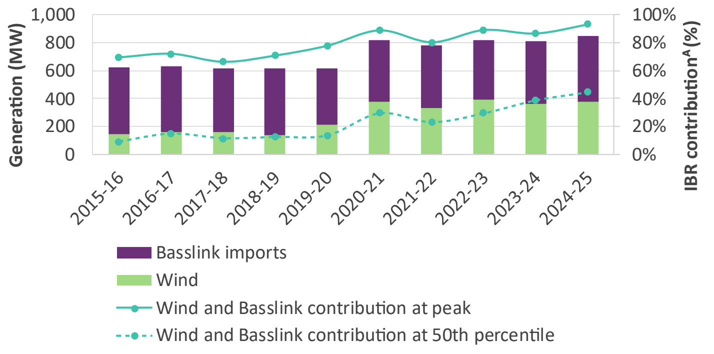
Context

The Tasmanian power system is driven by high proportions of highly flexible hydro electric generation while benefitting from additional wind generation, allowing the region to already operate at 100% renewables. However, Tasmania is currently unable to operate at 100% inverter-based resources because of limited frequency control capability if Basslink is unavailable.

System security is heavily supported by Tasmania's fleet of hydro generators, most with synchronous condenser capability, with back up gas generation to support years with lower dam levels. These are expected to remain into the future.

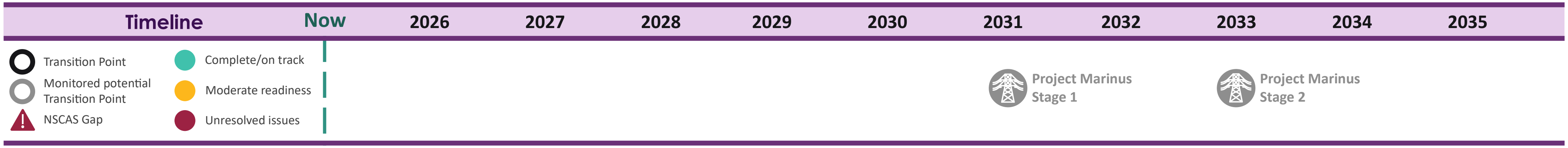
No transition points have been identified for Tasmania in this year's TPSS, however AEMO is monitoring the introduction of Project Marinus as this may impact market outcomes, provide additional system security support and impact frequency control requirements.

Wind and Basslink imports are making greater IBR contributions



Tasmania is now regularly seeing IBR contributions of 94%

Tasmania remains reliant on hydro units for system security



Security challenges

Project Marinus Link Stage 1 and 2 are expected to have 750MW capacity each. This is significantly greater than Tasmania's current largest possible contingency of a Basslink trip while at full capacity, around 450MW.

AEMO believes the potential transition points of Marinus Link Stage 1 and 2 can be managed using existing technologies and sufficient time is available to assess impacts over future Transition Plans for System Security.

Actions

- **TasNetworks** to progress system strength RIT-T to meet short term obligations. Long term minimum and efficient system strength requirements managed by TasNetworks through the RIT-T framework.
- Long-term inertia remediation may be possible alongside system strength remediation measures.

A. TasNetworks use the System Non-Synchronous Penetration (SNSP) ratio to measure IBR contribution. SNSP is the ratio of generation from wind and Basslink HVDC imports to operational demand. A full equation is also available in AEMO's 100% Inverter Based Resource Generation Study – Tasmanian Region report, see: https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2023/tasmania-100-percent-ibr-generation-study.pdf

Tasmania

REGIONAL DEVELOPMENTS	Now	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Synchronous generator capacity change *Annual capacity changes (MW)*											
Committed and anticipated IBR *Annual capacity changes (MW)*		+21		+287	*Future project details periodically evaluated in NEM generation information processes*						
IBR forecasts (*Sets efficient Sys. Strength level)* *Annual capacity changes (MW)*		+21		+587	+573	+327	+109	+311			
Transmission augmentation		TasNetworks system strength RIT-T Contracting with existing synchronous condenser and generation owners to provide system strength				Waddamana to Palmerston upgrade	Project Marinus Stage 1		Project Marinus Stage 2		

● Committed/anticipated

● RIT-T in progress/actionable

Transition Points

○ Transition Point

○ Potential Transition Point being monitored

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
						Project Marinus Stage 1		Project Marinus Stage 2		

AEMO'S CURRENT OUTLOOK	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Assessment horizon	***NSCAS assessment** (See Appendix 2)*					***Long term assessment***				

System strength – *nodal assessment* (minimum fault current in MVA)

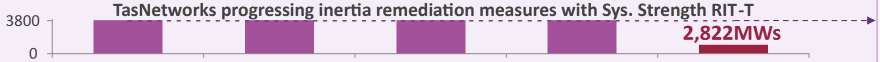
Long-term, system strength requirements are managed by TasNetworks through the RIT-T framework.

TasNetworks' RIT-T concluded with the Project Assessment Conclusions Report (PACR) released June 2025. The PACR has determined that contracting with existing generators to provide system strength is the preferred option and will meet TasNetworks' system strength obligations until June 2029.

For long term system strength requirements, the TasNetworks' PACR indicates future modelling for the 2030 period and beyond will be considered in their next system strength RIT-T.

Inertia (MWs)

TasNetworks progressing inertia remediation measures with Sys. Strength RIT-T



Low long-term risk due to high proportions of synchronous generation expected into the future and TasNetworks inertia contracting to meet requirements.

Thermal and voltage

No thermal loading or voltage control gaps identified

AEMO and TasNetworks' monitoring of thermal loading and voltage control gaps over the transition.

------ Requirements ▨ Available level 🟥 Deficit ⚠ NSCAS Gap

Victoria

Context

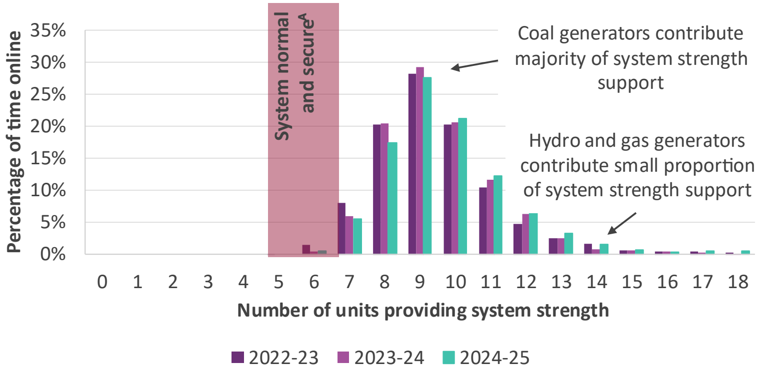
Victoria's remaining three coal plants are approaching end of life, with Yallourn Power Station scheduled to close in July 2028. The Victorian Government also has a Structured Transition Agreement (STA)[B] for the orderly closure of Loy Yang A by June 2035. While the STA is expected to ensure Loy Yang A remains available to satisfy the reliable and secure supply of electricity in Victoria, it may still be prudent for industry to prepare for periods where coal units could be displaced by other generation in the market, or become operationally unavailable, ahead of planned retirement dates.

These decommitments are potential transition points, particularly because these plants currently provide the majority of system strength in Victoria – in combination with smaller gas and hydro units. AEMO issued directions for system strength in Victoria in October 2025, when multiple coal units were on outage.

The other identified transition point relates to minimum system load (MSL) conditions.

Victoria has several major network augmentation and interconnection projects under construction or progressing through the RIT-T framework. VRE projects are expected to develop in REZ's across the state, and the government is targeting substantial offshore wind developments off the coast at Gippsland and Portland.

Available units to meet system strength requirements are close to security limits



Yallourn Power Station exit removes four synchronous generating units

Network augmentation and synchronous condensers will reduce limit

Timeline **Now** **2026** **2027** **2028** **2029** **2030** **2031** **2032** **2033** **2034** **2035**

Transition Point

Monitored potential Transition Point

NSCAS Gap

Complete/on track

Moderate readiness

Unresolved issues

Vic MSL

Yallourn exit

Vic 2nd coal station potentially offline

Vic 3rd coal station potentially offline

Security challenges

Delivery of synchronous condensers and planned metro grid reinforcement projects will help manage system strength and improve transfer capacity - limited by thermal constraints - into metropolitan Melbourne following the exit of Yallourn Power Station. If there are delivery delays, AEMO may need to rely on contracts or directions for managing reduced network and generator outage planning margins, and declines in system strength and inertia. Operationally these actions will be coupled to the status of Loy Yang power station units. If these units are on forced or planned outages, the power system will likely utilise gas generators, whose gas supply may be limited.

During typical system normal conditions: MSL incidences for which DNSPs must enact emergency backstop measures will remain rare provided that system security investments are delivered on time and in full and there is enhanced flexibility of CER to manage output in the middle of the day. During rare but plausible onerous conditions, the amount of operational demand increase required may mean that all the mechanisms at the disposal of DNSPs are utilised, including shedding of some reverse-flowing feeders. This indicates a need to consider enhancing available mechanisms.

Actions

Notwithstanding the Victorian Government's agreement with Loy Yang A[B] , it may be prudent for **VicGrid** and the **Victorian Government** to consider additional security assets, including synchronous condensers, or bringing forward existing ISP actionable transmission upgrades as physical insurance against coal units coming offline earlier than expected . Actions include:

- **VicGrid** to monitor the likelihood of these transition points and their impacts on thermal limits as the Eastern Victorian Grid Reinforcement[C] and Western Metropolitan Melbourne Reinforcement[D] RIT-Ts progress.
- **VicGrid** to consider contracting with existing assets to manage operational risks ahead of on time and in full delivery of new projects. This includes the potential retrofit of existing plants with synchronous condenser capability as per their system strength RIT-T[E].

A. Secure requirement for Victoria is satisfied through a combination of coal, hydro and gas units. Coal units contribute greater proportion to system strength, compared to hydro and gas units.

C. See https://www.aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf

E. See https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf

B. See https://www.agl.com.au/about-agl/news-centre/2023/august/loy-yang-structured-transition-agreement

D. See https://www.aemo.com.au/-/media/files/initiatives/western-metropolitan-melb-reinforcement/western-metropolitan-melbourne-reinforcement-project-specification-consultation-report.pdf

Victoria

REGIONAL DEVELOPMENTS	Now	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Synchronous generator capacity change *Annual capacity changes (MW)*					-1,450				-170		-2,210
Committed and anticipated IBR *Annual capacity changes (MW)*		+3,397		+1,612	+661	*Future project details periodically evaluated in NEM generation information processes*					
IBR forecasts (*Sets efficient Sys. Strength level*) *Annual capacity changes (MW)*		+3,397		+5,262	+2,475	+2,178		+1,948	+637	+666	+607
Transmission augmentation ● Committed/anticipated ● RIT-T in progress/actionable				PEC 2		WRL Western Metro RIT-T	Project Marinus 1 Eastern RIT-T	VNI West	Gippsland shoreline REZ Project Marinus 2	Voltage RIT-T	
		① Ararat synchronous condenser		System strength RIT-T synchronous condensers			③			④	⑤

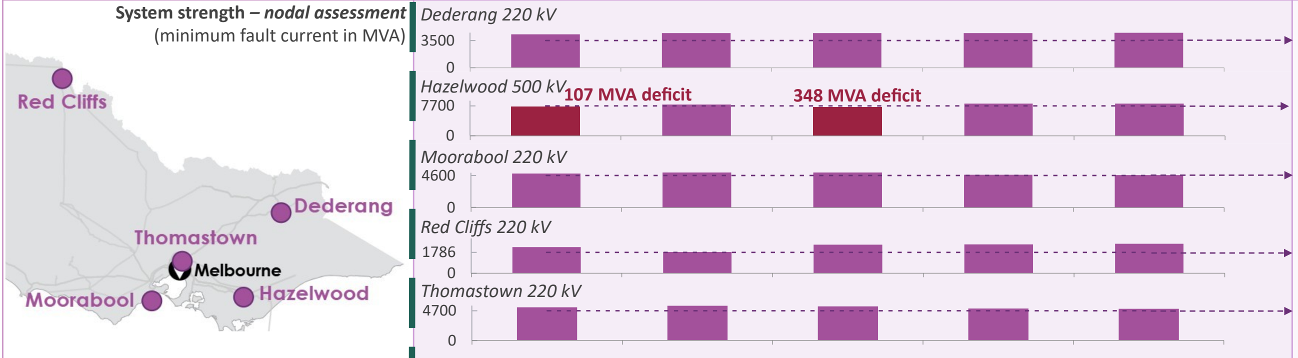
Transition Points

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
		Vic MSL		Yallourn exit			Vic 2nd coal station potentially offline		Vic 3rd coal station potentially offline	

AEMO'S CURRENT OUTLOOK

	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
Assessment horizon	***NSCAS assessment*** *(See Appendix 2)*					***Long term assessment***				

System strength – *nodal assessment*
(minimum fault current in MVA)



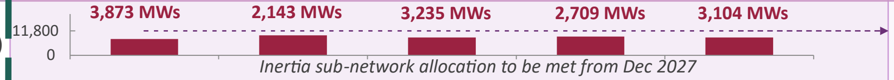
Long-term, system strength requirements are managed by VicGrid through the RIT-T framework.

VicGrid's RIT-T is now complete[A], with publication of the Project Assessment Conclusions Report phase by AEMO Victorian Planning in August 2025. VicGrid are currently in contractual negotiations with existing synchronous machines and GFM BESS to provide system strength services and have commenced initial stages of procurement.

The preferred portfolio option includes plans to install synchronous condensers at Hazelwood and contract with synchronous generation to meet minimum fault level requirements. Delivery of VicGrid's system strength RIT-T on time and in full will be critical to keeping system strength above minimum requirements.

AEMO also recommends that any new synchronous condensers procured for system strength be appropriately specified to provide inertia support services.

Inertia (MWs)



Inertia deficits are expected in the early years of the transition, as coal progressively decommits. VicGrid is investigating options, including contracting for inertia alongside meeting its system strength requirements.

Thermal and voltage

Thermal and voltage risks at Deer Park Terminal Station are currently managed through control scheme. Powercor and VicGrid are progressing investment options[B] to remediate this risk.

VicGrid are progressing investment options[C,D,E] to address overloads risks in the east and west as Victoria relies on IBR in REZs and imports from New South Wales

- - - - Requirements ▨ Available level ■ Deficit ⚠ NSCAS Gap

A. See https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf

B. See https://www.aemo.com.au/-/media/files/initiatives/metropolitan-melbourne-voltage-management-rit/melbourne-metropolitan-voltage-management-project-assessment-draft-report.pdf

C. See https://www.aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf

D. See https://www.aemo.com.au/-/media/files/initiatives/western-metropolitan-melb-reinforcement/western-metropolitan-melbourne-reinforcement-project-specification-consultation-report.pdf

E. See https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan

Minimum System Load – Victoria

5-year outlook

Victoria

Moderate readiness

Assessed

- System strength
- Frequency and inertia
- Voltage control
- Operability
- Resource adequacy

To be assessed

- System restoration
- Transient and oscillatory stability

Context

Victoria has experienced a record minimum 30-minute operational demand of 1,504 MW (1 January 2025 12:30), this contrasts with a maximum demand of 10,576 MW (29 January 2009). Minimum system load (MSL) risk is projected to increase, with the 2025 ESOO anticipating operational demand to fall by 400MW a year as well as risks of coincident MSL events in neighbouring regions.

Impacts

As MSL continues to decline, technical challenges begin to emerge. AEMO currently determines MSL thresholds according to the level of demand needed to operate the minimum combination of synchronous generating units required to maintain security[A]. Under plausible onerous conditions, demand in Victoria may need to be maintained at or above 2,190 MW (reducing to 2,073 MW with new utility-scale BESS in Spring 2026) to ensure provision of essential system services.

If MSL2 or MSL3 conditions are forecast, AEMO takes actions to clear the condition. Current AEMO actions in Victoria include recalling outages, decommitting synchronous units, and procuring Type 1 transitional services (BESS MSL resecure services) through LaTrobe Valley and Hazelwood BESS.

If MSL3 conditions persist following AEMO actions, or MSL3 is forecast without sufficient lead time for AEMO actions to take effect and clear the condition, AEMO instructs NSPs to maintain operational demand above the required threshold to maintain system security. Present capabilities for Victorian DNSPs include:

- Curtailing embedded generators including non-scheduled PV (PVNSG)
- Load shifting from hot water
- Active DER management via CSIP-AUS (since October 2024 for sites <200kVA, via the Victorian Backstop Mechanism)
- Emergency voltage management (EVM), the deliberate increase of distribution voltages to disconnect distributed PV[B].

MSL Outlook[C] *Refer to TPSS Part C and Appendix 3*

Under typical system normal conditions: if coal generation exits and network investments proposed proceed as planned, all forecast MSL3 in Victoria over the outlook horizon are projected to be resolved via AEMO actions and export into other regions. Any delays in delivery of synchronous condensers and network augmentation projects may increase the number of events requiring operational management from as early as 2027-28. Coordination of large-scale storage and CER may help to decrease the need for intervention in the outlook period.

Rare, but plausible, onerous system conditions are modelled assuming 1) typical large synchronous units operating at minimum levels, and 2) zero export and zero import into Victoria, due to network outages or coincident low demand in neighbouring regions. The modelling also considers an additional 0.5GW/1GWh of utility-scale BESS installed in 2026.

Under such rare, but plausible onerous system condition: managing an MSL3 event could require full application of MSL3 operational demand increase mechanisms at Victorian DNSPs' disposal. In the absence of further actions (see below), if such onerous conditions were to occur in Spring 2026 and coincide with very low demand periods, it could be necessary to shed some reverse-flowing feeders.

Actions

The development of activities to ensure a smooth transition and provision of essential services in Victoria is underway, as detailed overleaf. Key recommended actions are detailed below:

- **NEM NSPs and industry** to target delivery, on time and in full, of planned investments for system security services and pathways to reduce generator minimum operating levels, to reduce the likelihood of future MSL3 events.
- **DNSPs** to continue to support urgent measures to improve compliance with existing mechanisms and consider if there are any further practicable opportunities to expand MSL3 actions available to increase operational demand as soon as possible to avoid reliance on reverse feeder shedding.
- **Industry and government** to consider further incentives for coordination of CER, particularly to support low demand periods. Refer to TPSS Part C for more detail[D].
- **AEMO** to continue to develop services, frameworks and actions with the aim to effectively incentivise utility-scale BESS to provide firm certainty of energy capacity throughout an MSL condition.
- **AEMO** is seeking expressions of interest to supply either Type 1 Transitional Services to address immediate MSL conditions or Type 2 Trial Services for novel solutions beyond 2028. Interested parties to consider opportunities to deliver these services for MSL[E].

A. This includes: MSL3: immediate action needed to increase demand; MSL2: system is one credible load contingency away from MSL3; and MSL1: system is two credible load contingencies away from MSL3. Further details on the strategies for managing MSL into the future can be found in Section 9.

C. Refer to Section 9.1 and Appendix A3 for further details.

E. For more information, visit https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning

B. In relation to EVM, DNSPs need to assess risks, consider pathways (including relevant regulations and legislation), conduct modelling, testing and/or trials as necessary to confirm whether this option is suitable for their network, while ensuring safety and low risk to customer equipment.

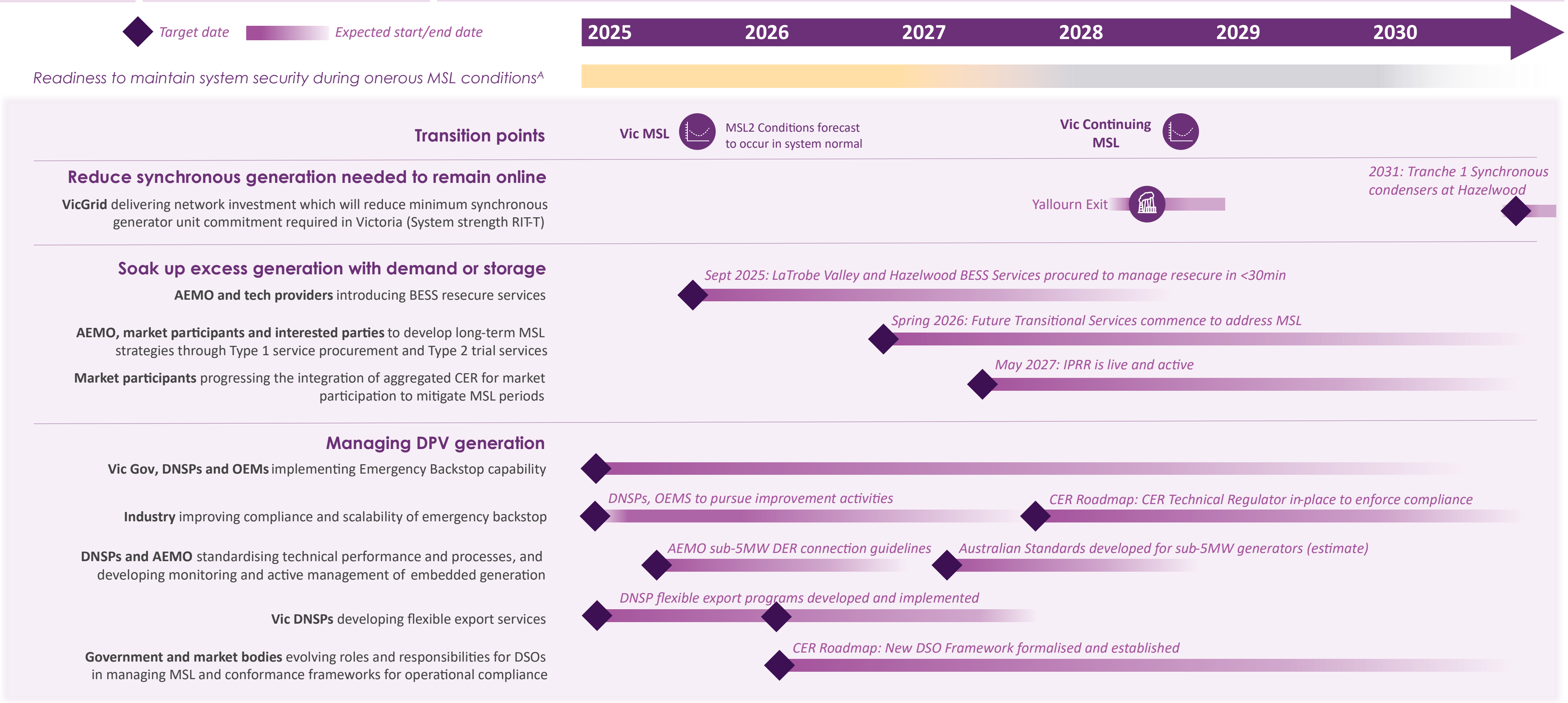
D. Refer to Part C for more detail

Minimum System Load – Victoria

5-year outlook | Victoria | Moderate readiness

Assessed: System strength · Frequency and inertia · Voltage control · Operability · Resource adequacy

To be assessed: System restoration · Transient and oscillatory stability



Readiness to maintain system security during onerous MSL conditions[A]

Transition points

Vic MSL — MSL2 Conditions forecast to occur in system normal

Vic Continuing MSL

Reduce synchronous generation needed to remain online

VicGrid delivering network investment which will reduce minimum synchronous generator unit commitment required in Victoria (System strength RIT-T)

- Yallourn Exit
- *2031: Tranche 1 Synchronous condensers at Hazelwood*

Soak up excess generation with demand or storage

AEMO and tech providers introducing BESS resecure services

- *Sept 2025: LaTrobe Valley and Hazelwood BESS Services procured to manage resecure in <30min*

AEMO, market participants and interested parties to develop long-term MSL strategies through Type 1 service procurement and Type 2 trial services

- *Spring 2026: Future Transitional Services commence to address MSL*

Market participants progressing the integration of aggregated CER for market participation to mitigate MSL periods

- *May 2027: IPRR is live and active*

Managing DPV generation

Vic Gov, DNSPs and OEMs implementing Emergency Backstop capability

Industry improving compliance and scalability of emergency backstop

- *DNSPs, OEMS to pursue improvement activities*
- *CER Roadmap: CER Technical Regulator in-place to enforce compliance*

DNSPs and AEMO standardising technical performance and processes, and developing monitoring and active management of embedded generation

- *AEMO sub-5MW DER connection guidelines*
- *Australian Standards developed for sub-5MW generators (estimate)*

Vic DNSPs developing flexible export services

- *DNSP flexible export programs developed and implemented*

Government and market bodies evolving roles and responsibilities for DSOs in managing MSL and conformance frameworks for operational compliance

- *CER Roadmap: New DSO Framework formalised and established*

A. Beyond 2027-28, there is a high level of uncertainty in the forecast of both MSL thresholds and capabilities of MSL actions available to NSPs.

Yallourn exit

Q3 2028

Victoria

● Moderate readiness

◆ Action required

Assessed

- System strength ◆
- Frequency and inertia ◆
- Voltage control
- Operability ◆
- Resource adequacy ◆

To be assessed

- System restoration
- Transient and oscillatory stability

Context

Yallourn Power Station is scheduled to close on 1 July 2028, reducing synchronous capacity supplying Melbourne from the Latrobe Valley. AEMO Victorian Planning (role now transferred to VicGrid) have been preparing for this event since EnergyAustralia's initial announcement in 2021. AEMO has operated the system securely without Yallourn for 4.5 hours in November 2024, following a forced outage event.

Impacts

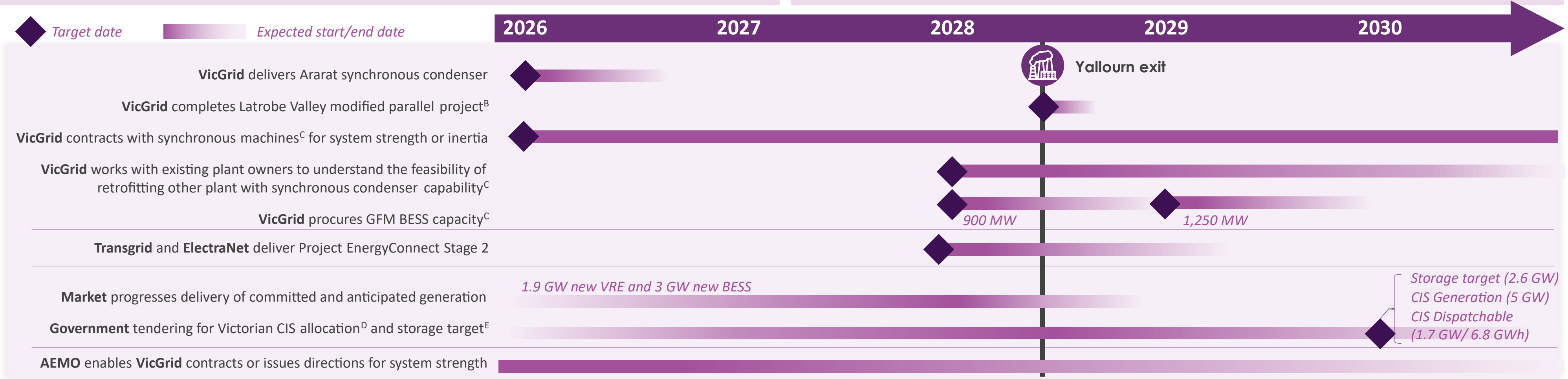
Network and generator outage planning margins are expected to reduce. Operational generator unit combinations to maintain system strength[A] are available but become limited, particularly under prior outage conditions at Loy Yang A and B.

In the event of a credible contingency, gas generation may need to be directed online to meet system strength and reliability requirements. Some gas generation may be unavailable due to gas supply constraints. Back up diesel supplies at some gas facilities may provide short-term support.

Transformer thermal loading limits between the 500 kV and 220 kV networks supplying metropolitan Melbourne would be breached but being resolved through network switching arrangement (Latrobe Valley modified parallel)[B].

Actions

- The Latrobe Valley modified parallel project[B] currently planned by **VicGrid** to manage thermal overloading is on track to be delivered by mid-2028.
- **VicGrid** is currently in contractual negotiations with existing synchronous machines to provide system strength services through the Victorian system strength RIT-T[C]. **VicGrid** is also working with existing plant owners to understand the feasibility of retrofitting plant with synchronous condenser capability. Delivery of these ahead of Yallourn closure will be critical.
- Investment in gas infrastructure projects required to make available sufficient fuel for GPG from 2029 onwards to manage ongoing risks to gas supply, reliability, and to support system security to a lesser extent.
- If Yallourn decommits or exits earlier than expected (e.g., due to plant failure), or if outages occur at Loy Yang A or B, **AEMO** may need to enable **VicGrid** system security contracts or issue directions.
- **AEMO** will further progress transition planning assessments, including system restoration and transient and oscillatory stability, as Yallourn closure enters Horizon 1 (0 – 2 year timeframe).



A. See https://www.vicgrid.com.au/__data/assets/pdf_file/0027/766152/victorian-transfer-limit-advice-system-normal.pdf

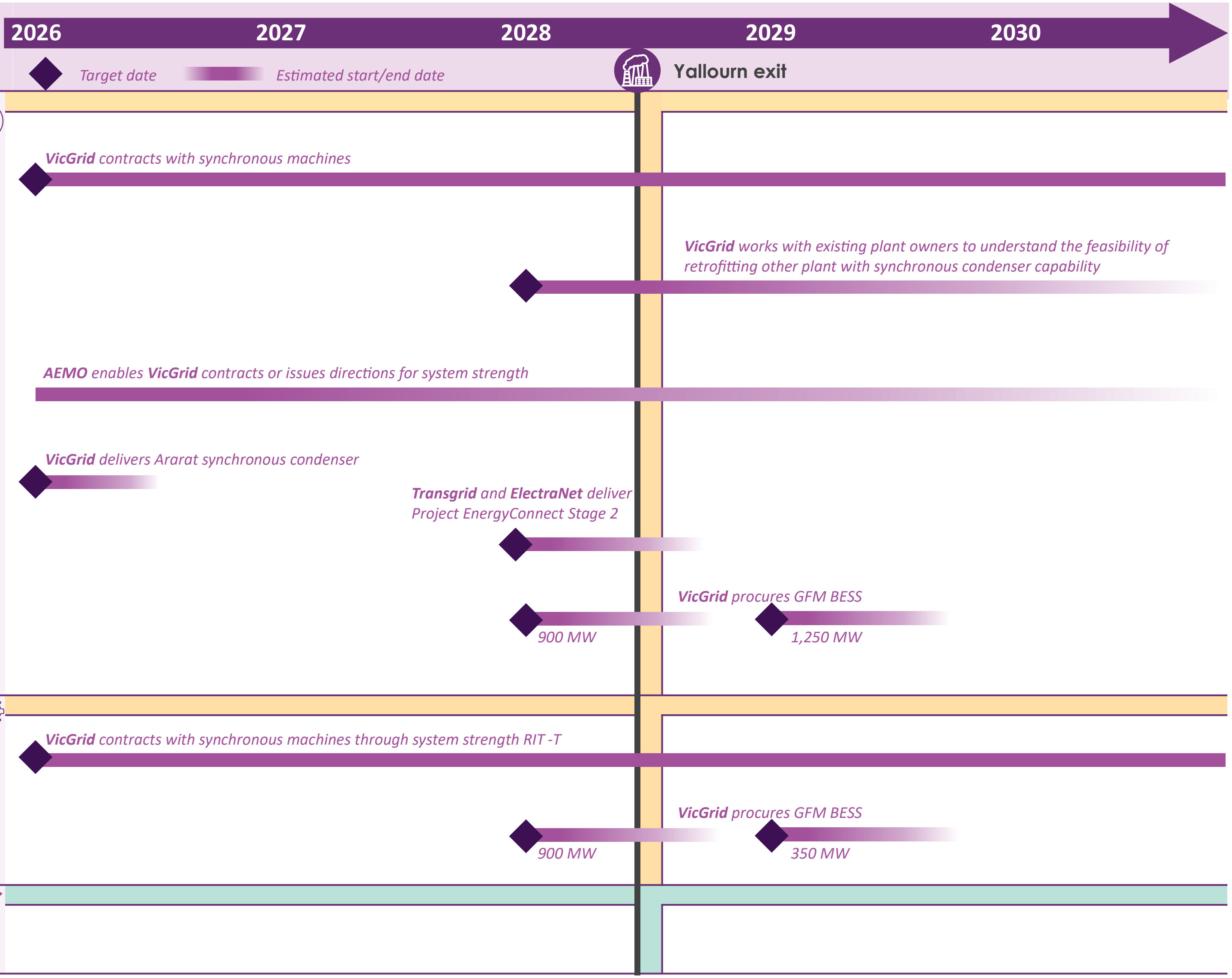
C. See https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf

E. See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets

B. See https://www.vicgrid.com.au/__data/assets/pdf_file/0039/769098/2025-victorian-annual-planning-report.pdf

D. See https://www.dcceew.gov.au/sites/default/files/documents/reta-allocations-market-brief.pdf

Yallourn exit



System strength

Yallourn's announced closure reduces options to maintain system strength above existing operational limits advice. **VicGrid** is procuring system strength services from existing synchronous generators to meet their system strength RIT-T[A]. **VicGrid** also plan to procure new synchronous condensers and work with existing plant owners to understand the feasibility of retrofitting other plant with synchronous condenser capability. Delivery of these projects is currently targeted to coincide with Yallourn closure, however any delay to delivery could extend the need for contracted services or operational interventions. Until **VicGrid** system strength solutions are delivered, most remaining system strength combinations[B] rely on at least 4 of 6 units coming from Loy Yang A or B. If three or more Loy Yang units were to be offline, interventions are likely to be required.

Limited but adequate operational options remain to meet minimum requirements through issuing directions to gas or hydro as last resort but these may be subject to constraints in fuel availability. **AEMO** may also resort to directions if Yallourn is offline earlier due to decommitment or protracted outages.

Network augmentation is progressing to support stability of existing and new IBR connections, required to provide reliable supply when Yallourn closes. Ararat synchronous condenser will allow stable connection of up to 600 MW IBR[C], while **Transgrid's** delivery of Project EnergyConnect Stage 2 will provide a reduction in effective network impedance and greater connectivity with new Ararat synchronous condenser and Melbourne[C]. **VicGrid** also planning for 900 MW GFM BESS to support the Moorabool system strength node[A].

Frequency and inertia

The decommitment of Yallourn is expected to reduce inertia levels below Victoria's sub-network allocation. **VicGrid** is investigating options available to meet its inertia requirements, including contracting services from existing synchronous machines, and provision of synthetic inertia from GFM BESS.

Voltage control

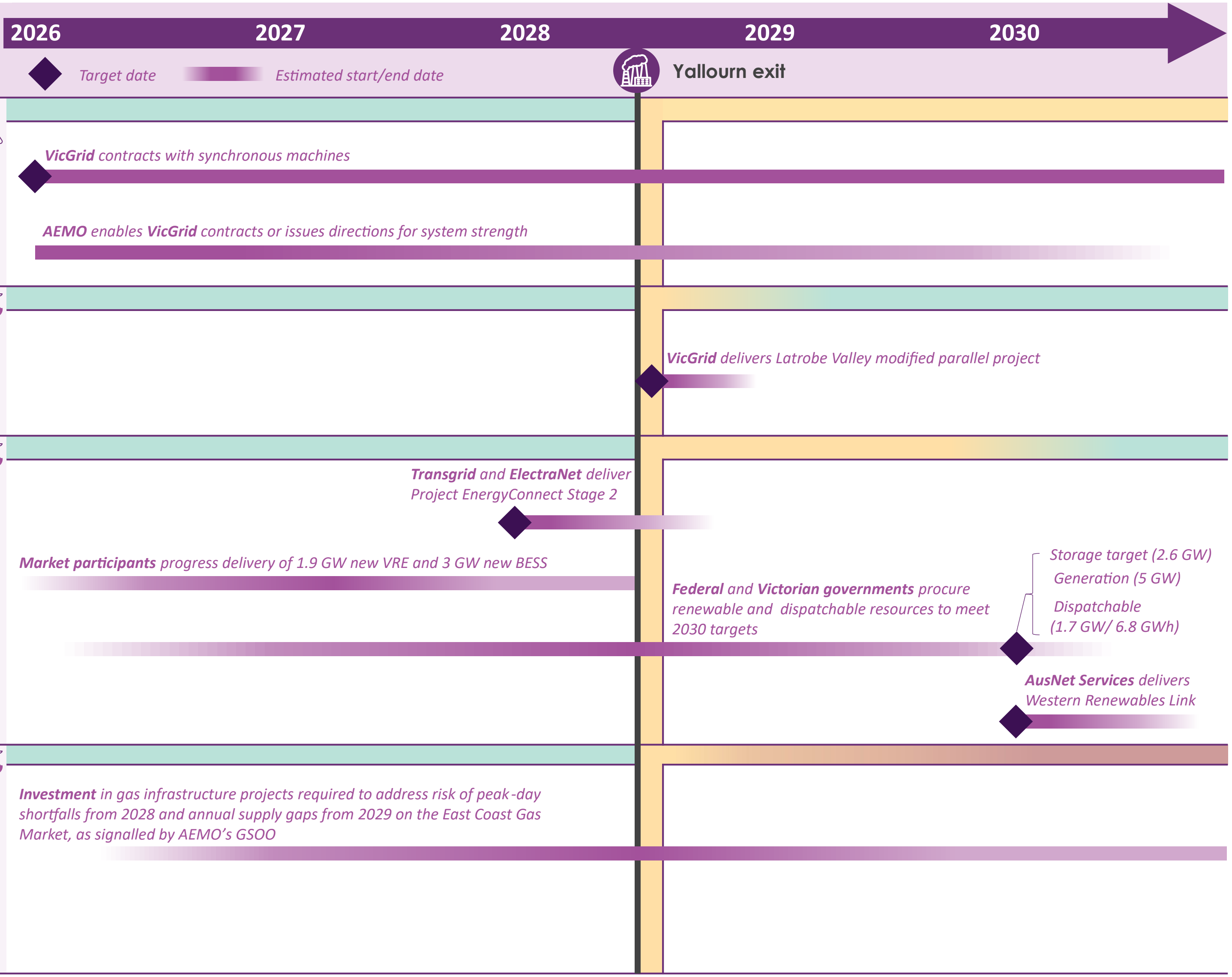
No identified voltage control risks related to Yallourn exit.

A. See https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf

B. See https://www.vicgrid.com.au/__data/assets/pdf_file/0027/766152/victorian-transfer-limit-advice-system-normal.pdf

C. See https://www.vicgrid.com.au/__data/assets/pdf_file/0039/769098/2025-victorian-annual-planning-report.pdf

Yallourn exit



Operability – outage planning

Until new network and generation assets are delivered, Yallourn exit on 1 July 2028 is expected to reduce margins for undertaking network and generator outages. New synchronous condensers required to reduce reliance on Loy Yang A or B are not expected until 2031. Until these are delivered, **AEMO** will enable **VicGrid** contracts or issue directions as needed to meet system strength requirements.

VicGrid *contracts with synchronous machines*

AEMO *enables* ***VicGrid*** *contracts or issues directions for system strength*

Resource adequacy – thermal limits

Transformer thermal loading limits between the 500 kV and 220kV networks supplying metropolitan Melbourne would be breached but will be resolved through network switching arrangement (Latrobe Valley modified parallel[A]).

VicGrid *delivers Latrobe Valley modified parallel project*

Resource adequacy – reliability

2025 ESOO[B] sensitivities were conducted for planned generator maintenance, drought conditions, and gas supply shortfall scenarios, assuming only committed and anticipated projects are developed. Results show reliability outside the Reliability Standard from 2028-29 onward if planned outages are uncoordinated and GPG cannot access gas supplies or hydro was constrained off by water availability. Progression towards **Federal** and **Victorian Government** supported generation targets[C,D], alongside Project EnergyConnect Stage 2 by **Transgrid** and **ElectraNet,** are expected to maintain reliability within Reliability Standard if delivered on time and in full, even under these resource limited sensitivities. Targets need active delivery mechanisms to ensure on time completion.

Transgrid *and* ***ElectraNet*** *deliver Project EnergyConnect Stage 2*

Market participants *progress delivery of 1.9 GW new VRE and 3 GW new BESS*

Federal *and* ***Victorian governments*** *procure renewable and dispatchable resources to meet 2030 targets*

Storage target (2.6 GW)
Generation (5 GW)
Dispatchable (1.7 GW/ 6.8 GWh)

AusNet Services *delivers Western Renewables Link*

Resource adequacy – gas adequacy

Availability of and run times for GPG, which AEMO may seek to direct for reliability and system security, depend on their access to fuel. Gas supply, storage and pipeline constraints are risks to GPG availability until new supplies and gas network upgrades are delivered. Some GPG facilities have diesel backup, however supply chain factors may limit this capability. GSOO[E, F] identifies investment opportunities in East Coast Gas Market infrastructure to address projected gas shortfalls and GPG fuel availability.

Investment *in gas infrastructure projects required to address risk of peak-day shortfalls from 2028 and annual supply gaps from 2029 on the East Coast Gas Market, as signalled by AEMO's GSOO*

A. See https://www.vicgrid.com.au/__data/assets/pdf_file/0039/769098/2025-victorian-annual-planning-report.pdf

B. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf

C. See https://www.dcceew.gov.au/sites/default/files/documents/reta-allocations-market-brief.pdf

D. See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets

E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2025/2025-victorian-gas-planning-report.pdf

F. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

Vic 2nd and 3rd coal stations potentially offline

2032-34

Victoria

● Moderate readiness

◆ Action required

Assessed

- System strength ◆
- Frequency and inertia ◆
- Voltage control
- Operability ◆
- Resource adequacy ◆

To be assessed

- System restoration
- Transient and oscillatory stability

Context

The 2024 ISP indicated that up to two units across Loy Yang A and B may consider mothballing by 2031-32, ahead of their publicly announced closure date, and that all Loy Yang units might decommit if market conditions allowed by 2033-34. Loy Yang A and B are also vulnerable to extreme weather events such as flooding of the open-cut mine shared by both plants.

While AEMO notes there is currently a Structured Transition Agreement[A] between the Victorian Government and Loy Yang A to manage its orderly closure by June 2035, it may remain prudent for industry to prepare for periods where coal units could be displaced by other generation in the market, or become operationally unavailable, ahead of planned retirement dates.

AEMO has considered two transition points to prepare for staged Loy Yang decommitment:

- *2031-32 Vic 2nd coal station potentially offline*: Two Loy Yang units start decommitting.
- *2033-34 Vic 3rd coal station potentially offline*: Plausible conditions with no coal units online.

Impacts

In order to enable Loy Yang decommitments in 2031-32 and 2033-34, on time and in full delivery of VicGrid's system strength RIT-T solutions, and transmission projects in Western Victoria, will be required to support system strength. This could include synchronous condensers and additional procurement (such as contracting) to both maintain available fault levels above minimum requirements, and to meet the stable voltage waveform requirements for the efficient level of system strength.

New assets deployed for system strength could also be procured with the ability to provide inertia and voltage control services.

Power flows into metropolitan Melbourne are expected to redistribute towards western Victoria (due to the wind resources there), exacerbating thermal overloading risks. The identified need in **VicGrid**'s RIT-Ts[B, C] would expand or emerge earlier than planned if both Loy Yang stations were to decommit ahead of currently announced timing. Thermal loading risks may also be offset by connecting new generation into the existing strong network in Latrobe Valley.

Greater reliance on GPG and batteries for reliability would be expected under these conditions. GPG availability will be subject to gas adequacy.

Actions

2031-32: Vic 2nd coal station potentially offline

- Through its system strength RIT-T[D], **VicGrid** will procure three new synchronous condensers to be installed at Hazelwood ahead of this potential transition point. Delays to synchronous condenser procurement would impact timing for this potential transition point.
- **VicGrid** also intends to procure GFM BESS[D] to support stability of new IBR.
- Thermal overloads will require network augmentation to improve transfer capability in the western metropolitan Melbourne area. Multiple investment tests by **VicGrid**, **AusNet Services**, and **Powercor** target upgrades in this area, including the Western Metropolitan Melbourne Reinforcement RIT-T[C]. The RIT-T has completed its PSCR stage assuming a 2035 timing of Loy Yang A closure. There may be value in bringing forward this upgrade to provide physical insurance against this potential transition point.
- Delivery of Western Renewables Link (WRL) by **AusNet Services** will provide some relief to thermal overloads in western Victoria, unlocking wind generation to replace loss of capacity from Loy Yang. WRL will also lower network impedance levels and strengthen the network between western Victoria and metropolitan Melbourne, providing metropolitan Melbourne improved connection with synchronous condensers at Ararat and Murra Warra, and western Victoria with improved connection to the existing synchronous generators in metropolitan Melbourne and the Latrobe Valley.
- Alternative generation may be supplied from new capacity at Latrobe Valley. The **Victorian Government** targets 2 GW of offshore wind generation by 2032[E]. **VicGrid** plans to develop offshore wind transmission[F] in Gippsland to enable this.

2033-34: Vic 3rd coal station potentially offline

- In addition to **VicGrid**'s system strength RIT-T[D], delivery of VNI West by **Transmission Company Victoria (TCV)** and **Iberdrola** would further improve the ability for metropolitan Melbourne to access synchronous resources in southern New South Wales and western Victoria to support system strength and reliability.
- As new synchronous and inverter-based plant connect, and as new transmission becomes energised, **AEMO** and **VicGrid** will work together to review system strength requirements and limits advice.
- Investment in East Coast Gas Market infrastructure[G] is needed to ensure ongoing availability of GPG.

A. See https://www.agl.com.au/about-agl/news-centre/2023/august/loy-yang-structured-transition-agreement

C. See https://www.aemo.com.au/-/media/files/initiatives/western-metropolitan-melb-reinforcement/western-metropolitan-melbourne-reinforcement-project-specification-consultation-report.pdf

E. See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets

G. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

B. See https://www.aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf

D. See https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf

F. See https://www.vicgrid.com.au/__data/assets/pdf_file/0032/761396/2025-victorian-transmission-plan.pdf

Vic 2nd and 3rd coal stations potentially offline

2032-34

Victoria

Moderate readiness

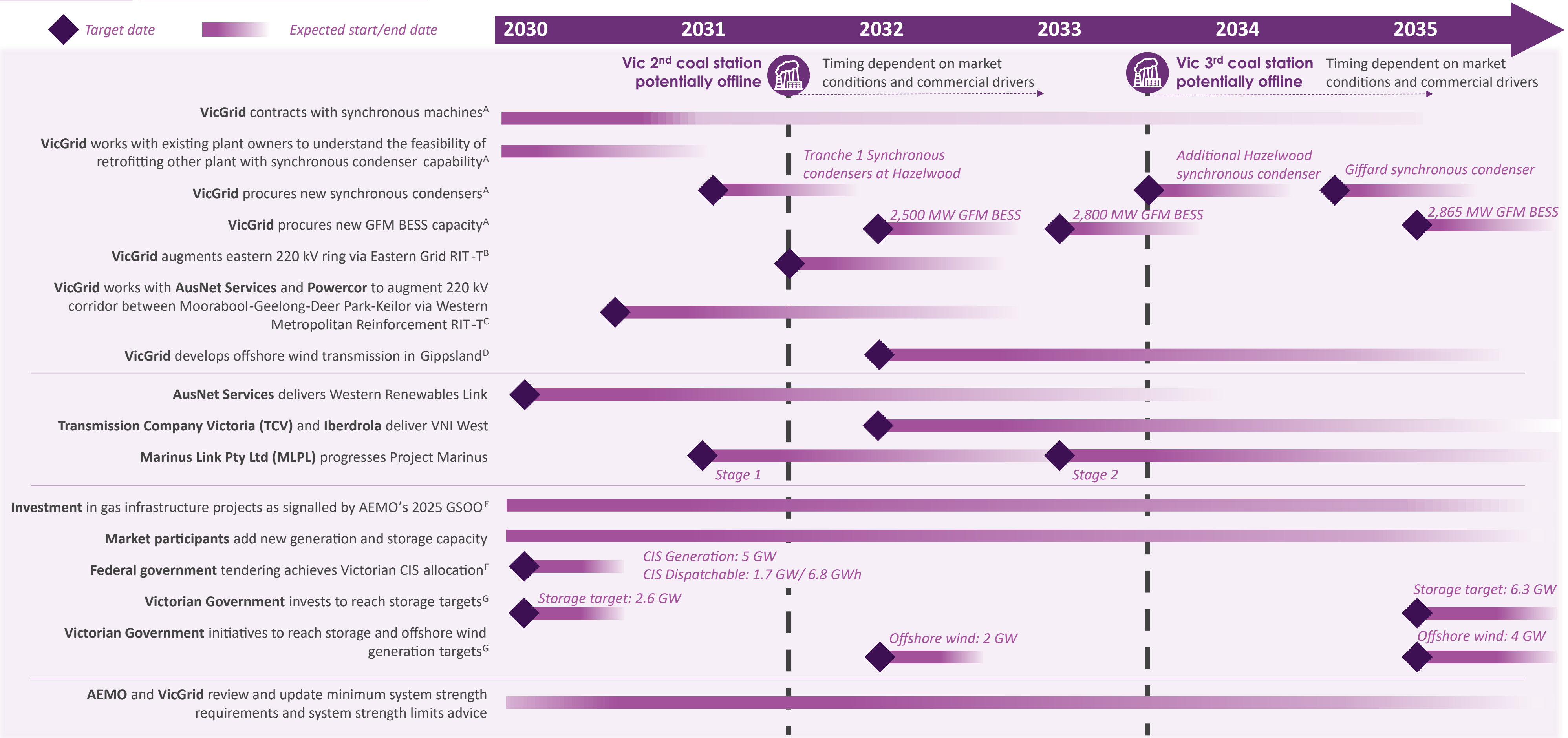
Action required

Assessed

- **System strength**
- **Frequency and inertia**
- **Voltage control**
- **Operability**
- **Resource adequacy**

To be assessed

- **System restoration**
- **Transient and oscillatory stability**



VicGrid contracts with synchronous machines[A]

VicGrid works with existing plant owners to understand the feasibility of retrofitting other plant with synchronous condenser capability[A]

VicGrid procures new synchronous condensers[A]

VicGrid procures new GFM BESS capacity[A]

VicGrid augments eastern 220 kV ring via Eastern Grid RIT-T[B]

VicGrid works with **AusNet Services** and **Powercor** to augment 220 kV corridor between Moorabool-Geelong-Deer Park-Keilor via Western Metropolitan Reinforcement RIT-T[C]

VicGrid develops offshore wind transmission in Gippsland[D]

AusNet Services delivers Western Renewables Link

Transmission Company Victoria (TCV) and **Iberdrola** deliver VNI West

Marinus Link Pty Ltd (MLPL) progresses Project Marinus

Investment in gas infrastructure projects as signalled by AEMO's 2025 GSOO[E]

Market participants add new generation and storage capacity

Federal government tendering achieves Victorian CIS allocation[F]

Victorian Government invests to reach storage targets[G]

Victorian Government initiatives to reach storage and offshore wind generation targets[G]

AEMO and **VicGrid** review and update minimum system strength requirements and system strength limits advice

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A. See https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf

C. See https://www.aemo.com.au/-/media/files/initiatives/western-metropolitan-melb-reinforcement/western-metropolitan-melbourne-reinforcement-project-specification-consultation-report.pdf

E. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

G. See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets

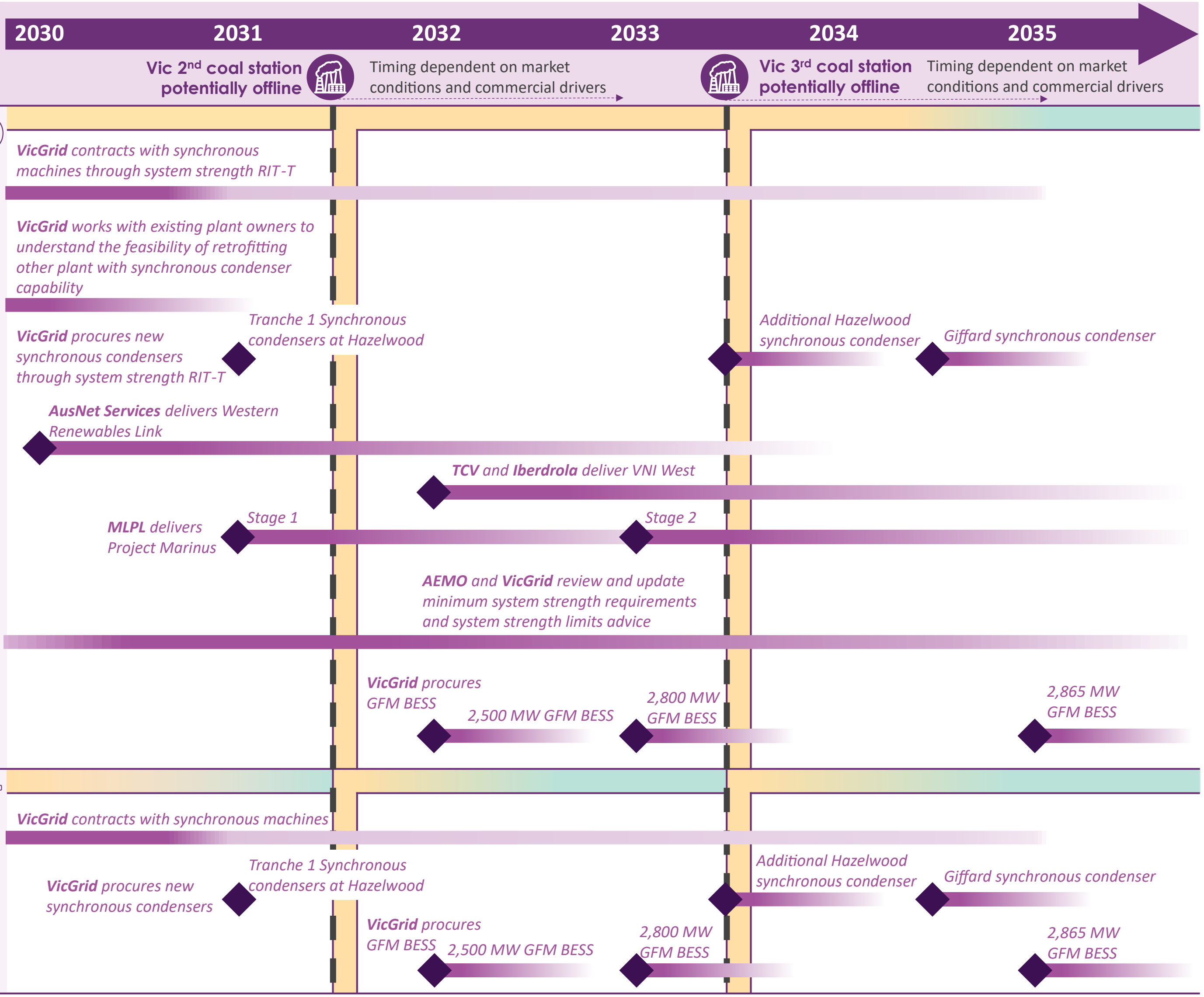
B. See https://www.aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf

D. See https://www.vicgrid.com.au/transmission-planning/victorian-transmission-plan

F. See https://www.dcceew.gov.au/sites/default/files/documents/reta-allocations-market-brief.pdf

Vic 2nd and 3rd coal stations potentially offline

◆ *Target date* *Estimated start/end date*



2030 2031 2032 2033 2034 2035

Vic 2nd coal station potentially offline
Timing dependent on market conditions and commercial drivers

Vic 3rd coal station potentially offline
Timing dependent on market conditions and commercial drivers

System strength

Available fault current reduces with Loy Yang decommitment. **VicGrid's** system strength RIT-T[A] will procure new synchronous condensers, with three before 2031-32 (decommitment of two Loy Yang units) and another by 2033-34 (potentially all coal units offline). **VicGrid** also plans to work with existing plant owners to understand the feasibility of retrofitting other plant with synchronous condenser capability. WRL and VNI West completion will improve the ability for metropolitan Melbourne to access synchronous resources in southern New South Wales and western Victoria, but long project lead times threaten on time delivery.

Unless investments in system strength assets and transmission are delivered on time and in full, operation after two-unit decommitment in 2031-32 could at times rely on **VicGrid** contracts with existing synchronous machines and **AEMO** directions to fuel constrained gas and hydro units.

To maintain sufficient minimum fault levels after decommitment of all coal units in 2033-34, AEMO studies find that **VicGrid**'s four new synchronous condensers, WRL and VNI West would all need to be completed, and that additional contracting would also be required. Contracting would be avoided if **VicGrid**'s planned fifth synchronous condenser at Giffard was brought forward.

Additional investments are required to support stability of existing and new IBR connections, which are required to provide reliable supply as Loy Yang progressively decommits. **VicGrid's** system strength RIT-T[A] plans to procure new GFM BESS to support this.

System strength requirements may change depending on entry of new plant, transmission, and the converter station design of Project Marinus. **AEMO** and **VicGrid** will update system strength requirement and limits advice as these changes occur[B].

__VicGrid__ contracts with synchronous machines through system strength RIT-T

__VicGrid__ works with existing plant owners to understand the feasibility of retrofitting other plant with synchronous condenser capability

__VicGrid__ procures new synchronous condensers through system strength RIT-T

Tranche 1 Synchronous condensers at Hazelwood

Additional Hazelwood synchronous condenser

Giffard synchronous condenser

__AusNet Services__ delivers Western Renewables Link

__TCV__ and __Iberdrola__ deliver VNI West

__MLPL__ delivers Project Marinus

Stage 1

Stage 2

__AEMO__ and __VicGrid__ review and update minimum system strength requirements and system strength limits advice

__VicGrid__ procures GFM BESS

2,500 MW GFM BESS

2,800 MW GFM BESS

2,865 MW GFM BESS

Frequency and inertia

VicGrid has determined that, while Loy Yang decommitment will reduce inertia levels, sufficient inertia services may be provided through synchronous condensers procured through the system strength RIT-T[A], if these are appropriately specified (i.e., with flywheels). **VicGrid** also plan to contract inertia services from existing synchronous machines and GFM BESS.

__VicGrid__ contracts with synchronous machines

__VicGrid__ procures new synchronous condensers

Tranche 1 Synchronous condensers at Hazelwood

Additional Hazelwood synchronous condenser

Giffard synchronous condenser

__VicGrid__ procures GFM BESS

2,500 MW GFM BESS

2,800 MW GFM BESS

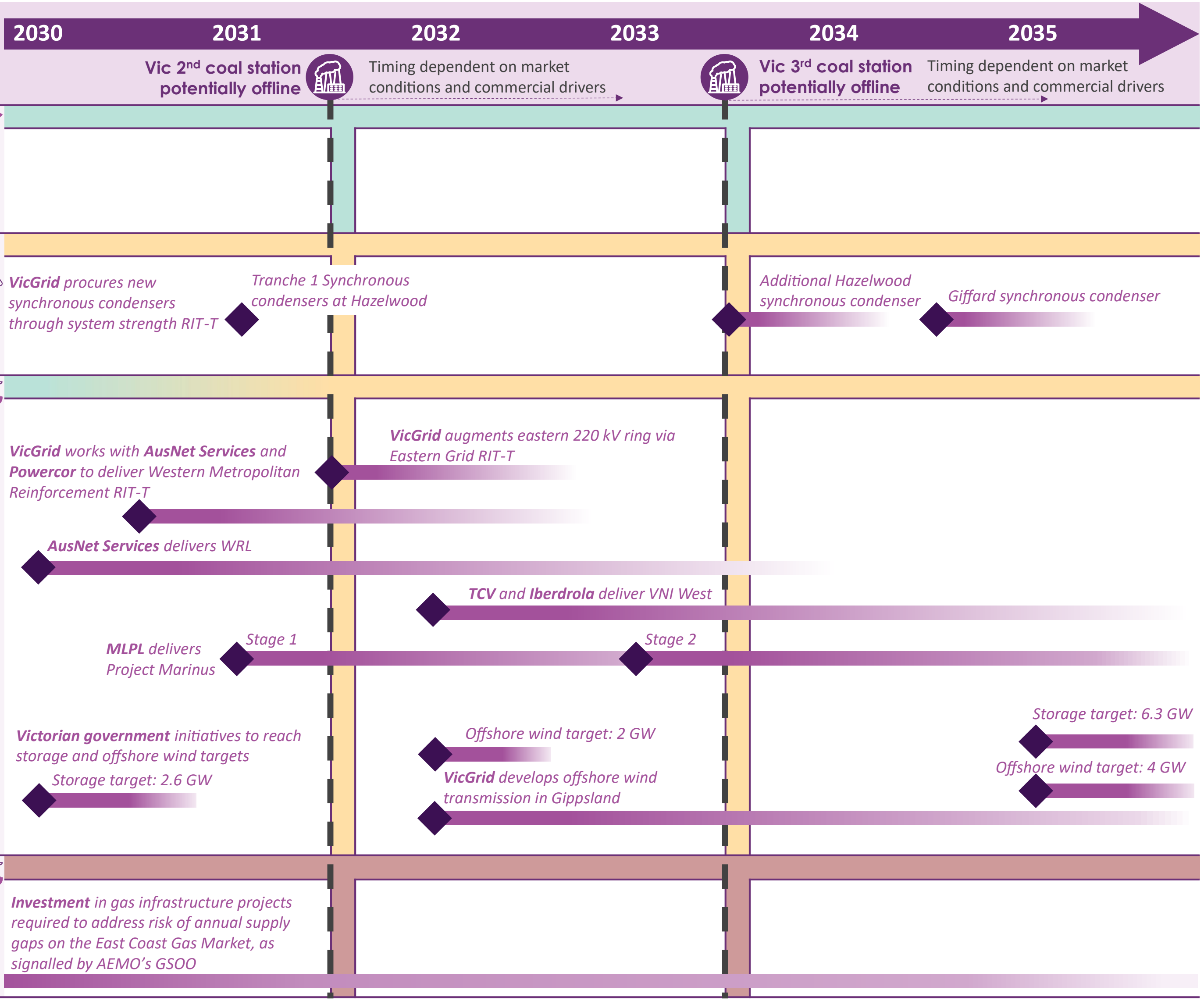
2,865 MW GFM BESS

A. See https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf

B. See https://www.vicgrid.com.au/__data/assets/pdf_file/0027/766152/victorian-transfer-limit-advice-system-normal.pdf

Vic 2nd and 3rd coal stations potentially offline

◆ *Target date* *Estimated start/end date*



Vic 2nd coal station potentially offline Timing dependent on market conditions and commercial drivers

Vic 3rd coal station potentially offline Timing dependent on market conditions and commercial drivers

Voltage control

No voltage control risks have been identified related to Loy Yang decommitment. Incoming IBR and synchronous condensers are expected to be installed with voltage control capability to manage demand fluctuations.

Operability – outage planning

Before delivery of new synchronous condensers and dispatchable capacity, planned outages at gas and hydro plant, and at remaining Loy Yang units, may have to be rescheduled to ensure reliability and security of the power system.

__VicGrid__ procures new synchronous condensers through system strength RIT-T

Tranche 1 Synchronous condensers at Hazelwood

Additional Hazelwood synchronous condenser

Giffard synchronous condenser

Resource adequacy – reliability and thermal limits

With reduced supply from Latrobe Valley, Victoria would rely more heavily on wind generation in the west, BESS and gas generation in metropolitan Melbourne, and import from New South Wales to meet peak demand. WRL unlocks some wind capacity from western REZs but is insufficient alone. Increased reliance on wind resources from REZs could mean the identified need to address thermal overloading in **VicGrid**'s existing RIT-Ts could increase. This includes **VicGrid'**s Eastern Victorian Grid Reinforcement RIT-T[A] to increase eastern metropolitan network capacity, and Western Metropolitan Melbourne Reinforcement RIT-T[B] to address thermal limitations will increase along the 220 kV corridor between Moorabool, Geelong, Deer Park, and Keilor. These RIT-Ts have completed their PSCR stages but are based on Loy Yang A's announced closure in 2035 and would need to be accelerated and expanded to fully support earlier decommitment if determined to be beneficial to consumers.

New supply being targeted for connection into the existing strong network in Latrobe Valley and delivery of Project Marinus could offset dependency on supply from western Victoria but will require careful planning to be operational in time to support resource adequacy for this transition point.

__VicGrid__ augments eastern 220 kV ring via Eastern Grid RIT-T

__VicGrid__ works with __AusNet Services__ and __Powercor__ to deliver Western Metropolitan Reinforcement RIT-T

__AusNet Services__ delivers WRL

__TCV__ and __Iberdrola__ deliver VNI West

__MLPL__ delivers Project Marinus

Stage 1

Stage 2

__Victorian government__ initiatives to reach storage and offshore wind targets

Storage target: 2.6 GW

Offshore wind target: 2 GW

__VicGrid__ develops offshore wind transmission in Gippsland

Storage target: 6.3 GW

Offshore wind target: 4 GW

Resource adequacy – gas adequacy

The 2025 ESOO[C] further showed that reliability in Victoria is highly sensitive to gas shortfalls. GSOO[D] identifies investment opportunities in East Coast Gas Market infrastructure to address projected gas shortfalls

__Investment__ in gas infrastructure projects required to address risk of annual supply gaps on the East Coast Gas Market, as signalled by AEMO's GSOO

A. See https://www.aemo.com.au/-/media/files/initiatives/eastern-victoria-grid-reinforcement/eastern-victoria-grid-reinforcement-pscr.pdf

B. See https://www.aemo.com.au/-/media/files/initiatives/western-metropolitan-melb-reinforcement/western-metropolitan-melbourne-reinforcement-project-specification-consultation-report.pdf

C. See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/2025-electricity-statement-of-opportunities.pdf

D. See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/2025-gas-statement-of-opportunities.pdf

Part C. System-wide developments and plans

Part C: System-wide developments and plans

While the fundamentals of power system security are enduring, how they are maintained is evolving. AEMO is working to improve the technical understanding of what is needed to achieve *power system security* in a low- or zero-emissions *power system*, including the range of services that may be required.

Part C of the *Transition Plan for System Security* provides detailed analysis of changes, challenges, and opportunities for power system security in the immediate-term and through the transition to a low- or zero-emissions power system.

- **Section 8 – Transmission level developments.** These are changes in the bulk energy system, including changing operating behaviour of thermal generators, processes for system restart, management of frequency, and challenges for protection and control systems from grid reconfiguration.
- **Section 9 – Distribution level developments.** Distributed energy resources (DER) and consumer energy resources (CER) are making increasingly significant contributions to the power system. This section explores how the operation of the power system may evolve to facilitate and harness this.
- **Section 10 – Technology developments.** This section focuses on three technologies that are having pronounced impacts on power system security and are expected to become more prominent in the future. AEMO is working to mitigate potential negative impacts and support improved understanding and confidence in new opportunities.
- **Section 11 – Horizon 3 and next steps.** Briefly surveys emerging technologies with significant security implications and discusses how AEMO's Engineering Roadmap activities progress readiness of emerging technologies and enhance understanding of the needs of a low- or zero-emissions power system through future-back analysis. Reporting on Engineering Roadmap activities will be integrated into the 2026 *Transition Plan for System Security*.

Collectively, these present AEMO's current technical understanding of what is needed to achieve *power system security* in a low- or zero-emissions *power system* and the work AEMO is undertaking to improve this understanding, including planned work towards refining the specifications for system security services.

8 Transmission level developments

The dynamics of the bulk energy system are changing, including as thermal generators operate more flexibly and retire, and BESS make significant contributions to frequency control. Collectively these changes also pose challenges for system restoration and protection systems.

This section discusses four changes occurring at the transmission and large-scale generation level:

- the evolving operation of thermal generators – to generate less, more flexibly – and their retirement,
- the need to develop and prove new procedures for system restart and incentivise new investments,
- the evolution of frequency controls, particularly as BESS make significant contributions, and
- challenges for protection and control systems from grid reconfiguration.

8.1 Evolving operation and market exit of thermal generation fleet

Key messages

- The NEM's thermal fleet is undergoing unprecedented structural changes, with accelerated coal decommitment and evolving gas-powered generation (GPG) roles, requiring alternative sources of system security for conditions of low synchronous generation.
- Flexible operational patterns of coal power plants and conversions to synchronous condensers offer opportunities but also introduce operational risks.

Key actions

- AEMO will monitor evolving operating generator behaviours to manage emerging risks, including potential future audits.
- On-time and in full delivery of network, generation and storage projects will mitigate many risks.
- Industry-wide uplift in modelling tools and real-time monitoring will assist secure operation with reducing synchronous generation.

8.1.1 Context

The power system was built around the physical characteristics of the thermal generation fleet. Coal-fired generation is progressively adopting more flexible operating modes, such as two-shifting and mothballing, mostly driven by market dynamics. These changes precede announced retirement schedules, which ultimately represent a significant reduction in synchronous machines that currently provide critical system security services. The eventual operation without any continuous synchronous generation represents a fundamental shift in system dynamics and operability.

GPG is also evolving from a primary function of more regular 'mid-merit' operation, to a more strategic and flexible back-up role both for 'renewable droughts' of 'dark and still' conditions, and to meet peaks in consumer demand. GPG is expected to be increasingly relied on during low variable renewable energy (VRE) and coal availability periods as well as at times when sufficient storage is not available. With a need for GPG to back up storages across the energy transition, it is essential that appropriate gas investment occurs to ensure the operability, reliability and security of the power system.

AEMO's 2025 *Thermal Audit*[57] provided detailed insights into challenges and opportunities of the evolving thermal fleet as well as station-level flexibility programs and their reliability implications affecting the operational life of the plants.

8.1.2 Latest status

The 2024 ISP *Step Change* scenario[58] forecast an accelerated rate of coal-fired power station decommitments, including scenarios with drastically reduced, or zero, coal units online far ahead of the announced retirement dates. The market dynamics incentivising coal-fired generation to decommit are also drivers for the enhancement of thermal plant operational flexibility. As reported in the 2025 *Thermal Audit* report and summarised in **Table 10**, these key flexibility enhancements are related to lowering minimum stable operating levels, enabling flexible operation modes (such as two-shift), and repurposing steam generating units to synchronous condenser operation. These changes can present both challenges and opportunities for the power system and warrant close engagement with participants to ensure they are effectively managed.

Table 10 Insights on operational shifts of the thermal generation

Key insights	Description
Flexibility impacts coal plants' reliability	Increased cycling and operation closer to physical limits (such as reduction of minimum stable operating level, increase maximum generation, ramp rate increase and reduction in hot restart time) correlates with increased plant wear and forced outage rates. Planned maintenance strategies are being adjusted to mitigate these risks, but uncertainty remains around coincident outages during peak demand periods.
Uncertainty of availability	Emerging shifts in operational patterns may result in additional short- and long-term offline periods that may challenge system security, operability, and reliability. It is paramount to drive preparedness well in advance of these events to proactively identify risks, remedial actions and contingency plans.
Conversions and repurposing opportunities	For GPG, enabling units to operate in both generating and synchronous condenser modes is technically feasible and actively explored within the industry. Steam units, however, present greater technical challenges and are generally better suited for repurposing to synchronous condensers. The 2025 *Thermal Audit* outlined this topic in detail, including feasibility, indicative conversion timelines, costs, and associated challenges.
GPG and gas network constraints	GPG is expected to be increasingly relied on for firming capacity and will remain critical for system security. However, gas adequacy and pipeline capacity constraints – particularly in southern regions – will need to be addressed so that locational flexibility for new developments is not restricted. The 2025 GSOO projected tightening gas supply in the upcoming years, with gaps emerging from 2028 onward, signalling the need for new fuel supply and infrastructure investment.

8.1.3 AEMO's forward plan

For reasons already discussed, thermal units are projected to be offline more frequently in years to come, meaning that system security services which have historically been available from large thermal units must be procured from alternative sources to meet the requirements. System restart pathways will require major redesign, and practices for managing frequency, voltage, and system stability must evolve significantly.

AEMO is preparing for the staged decommitment and retirement of thermal generators using the transition planning framework (see Part A Section 2.2). Despite rigorous planning and detailed scenario analysis, uncertainties remain that

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[57] At https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/2025-thermal-audit.pdf.

[58] The 2026 ISP, currently under development, is not expected to material deviate from this forecast.

shape both operational risk such as infrastructure and generation delivery timing, and the timing and sequence of plant decommitments.

Preparing for these milestones requires strong industry collaboration and accelerated delivery of critical network infrastructure, generation, and energy storage projects. Significant uplifts in planning, analytical tools, modelling capabilities, and real-time operational practices are needed, with few initiatives already underway as discussed in Part A. At the same time, robust contingency plans are essential to manage risks.

8.2 Planning future system restart

Key messages

- Existing system restart pathways could become unviable after coal and other large synchronous plant retire and are likely to require redesign to support a high VRE and IBR power system.
- AEMO and industry must develop and test alternative restart pathways, without soon-to-retire plant at least a year ahead of retirements and other transition points that impact system restart.
- AEMO expects near-term changes to be incremental, with restart processes to remain primarily focused on restarting existing large grid-connected plant and priority load centres.
- In parallel, collaboration is required to develop new approaches and procedures to restart each NEM region for once coal stations have decommitted or exited. This requires a co-ordinated program of testing, modelling, and timely, targeted investment.

Key actions

- In 2026, AEMO will build on this *Transition Plan for System Security*'s preliminary analysis to refine SRAS capacity requirements after 2030, to support restoration without reliance on coal units.
- AEMO has commenced procurement of two Type 2 Transitional Services to demonstrate black start capability using IBR and support system restart under high distributed photovoltaic (DPV) conditions.
- Following finalisation of the System Restart Standard (SRS) review at the end of 2025, AEMO will update the SRAS Guideline and commence the 2027 system restart ancillary services (SRAS) procurement round. SRAS procurement will include opportunities for restoration support services (RSSs) to address near-term stable load unavailability.
- Prior to demonstration with confidence of alternative technologies, it is likely that black start sources will need to be synchronous generating units – either new hydro or gas generation. AEMO encourages any party considering the deployment of a large (100 megavolt amperes [MVA]+) synchronous generating unit contact AEMO at nmas@aemo.com.au to explore the potential to support future system restoration processes.
- As noted in AEMO's submission to the draft SRS, investment frameworks need to suitably incentivise investment in system restart, in both black start sources and RSSs. AEMO is working with the Reliability Panel and AEMC to support relevant reform efforts that help incentivise SRAS investment and test potential new restart methodologies

8.2.1 Context

System restoration refers to the process of re-energising the electricity grid following a black system event. In the NEM, AEMO procures SRAS and coordinates system restart plans with industry to gradually rebuild supply and stabilise the network along identified restart pathways.

A system restart pathway begins at a black start SRAS source that can start independent of the grid's status. The black start source forms a restoration island, which then progressively energises transmission lines, substations, and neighbouring generators to expand the restoration island. This staged approach restores power safely, reliably, and in a controlled sequence, minimising risks of instability or further outages that could delay restoration. Supporting generation or services can also be required along the path to maintain the island – these are known as restoration support services (RSSs).

SRAS, which is procured by AEMO, forms a critical part of the NEM's system security, but it is only one piece of the restart framework. Industry collectively plays a role in ensuring that restart plans and infrastructure are in place for timely and effective system restoration. This includes network service providers who are responsible for their network assets along the restart pathway, all generators and loads who are responsible for their local black start procedures, and market participants that are directly contracted to provide SRAS. Technical and operational coordination across all these parties, especially for those who participate in the early stages of system restart, is critical to system restoration.

To date, system restart plans have been built around coal, gas and hydro plants restarting other large synchronous plant, often coal, to build a stable island from which to grow the network. The exit of coal generation drives the need to consider new approaches to restart to be developed for the NEM regions before significant synchronous generator retirements, or traditional SRAS providers exit the market.

To address immediate and longer-term challenges requires a parallel approach from all stakeholders. The 2027 procurement round for SRAS will focus on incremental change, including adopting the recently updated System Restart Standard (SRS) requirements (see Section 8.2.2) and addressing near-term stable load block availability. In parallel, collaboration is required to develop new approaches to restart once coal stations have decommitted or exited.

8.2.2 Latest status

Near-term system restart procurement efforts

In June 2025, AEMO published its System Restart Technical Advice, prepared as an input into the Reliability Panel's 2025 Review of the System Restart Standard[59]. The Reliability Panel's Draft determination currently proposes revisions to the SRS, including the introduction of a dual procurement target framework, an eight-hour supply restoration procurement objective for Stage 2 of this target, and an increase in aggregate reliability of procured SRAS to 95%. A final determination is expected to be completed by the end of 2025.

AEMO intends to begin updating and consulting on a revised SRAS Guideline following the SRS Final Determination at the end of this year. This will then inform the 2027 procurement round for SRAS including procurement of both Black Start Services (BSSs), and RSSs where required to support a system restart pathway. For example, RSSs could provide stabilising load blocks for ramping system restart generators, or adequate voltage control along a restart path. BESS are anticipated to be a valuable provider of RSSs.

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[59] See https://www.aemc.gov.au/market-reviews-advice/review-system-restart-standard-0.

As noted throughout the *Transition Plan for System Security*, high levels of DPV uptake are occurring across most regions in the NEM. When there are high concentrations of DPV located along the restoration path, this can result in load variations and erosion impacting the availability of stabilising load blocks to support system restart generators during the early stages of restoration. In the absence of further action, it is possible that at times there may be insufficient stable demand to restart the system. The restoration process would then need to be delayed until low DPV operating conditions are available such as at night. To increase availability of stable load blocks during daytime hours, AEMO may look to procure load Restoration Support Services from specific BESS at certain locations to support existing system restart pathways.

As noted in Part A Section 2.3.2, AEMO has also recently commenced market engagement on two Type 2 Transitional Services relevant to system restart:

- release of a Statement of Need describing the procurement of a Type 2 Transitional Service for "System Restart under High DPV Conditions", seeking to demonstrate emerging technologies and operational approaches capable of managing DPV/CER reconnection on the system restart process, particularly during times where communications infrastructure is unavailable[60], and
- release of a Statement of Need[61] describing the procurement of a Type 2 Transitional Service to demonstrate black start capability from an IBR. This aims to provide technical and commercial confidence for future procurement, and support the development of future system restart methodologies and timely investment in black start capability before key coal plant retirements.

New black start investment

AEMO has considered how procurement of black start services against the Draft Determination of the System Restart Standard[62] may occur. Assuming similar market response to previous procurement rounds, AEMO has found:

- at least two black-start SRAS services may need to be procured in each region from 2027 through to 2030, with the ability to procure more to meet the SRS in each region if required, and
- at least three black start SRAS services may be needed per region from 2030 onwards, depending on factors such as development of new methodologies, evolving technical frameworks, and demonstration of new technology restart capabilities.

In Queensland, reducing availability in black-start capable generation is becoming evident. Additional investment is likely required to support existing black start sources by ensuring availability of sufficient load blocks to support stable operation of generating units, whilst ensuring sufficient generation is available to restore major industrial load within critical restoration timeframes.

As the transition progresses, there will potentially be an increased need for additional black start services to enable new restart pathways. The required size of black start generators will depend on location and proximity to neighbouring generators requiring energisation. If positioned strategically near other generation plants, the generator could be as small

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[60] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/system-restart-under-high-dpv-conditions-service.

[61] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transition-planning/type-2-services/statement-of-need-black-start-from-ibr.pdf.

[62] See https://www.aemc.gov.au/sites/default/files/2025-09/Draft%20standard_CLEAN.pdf.

as 100-150 MVA in size. However, if the black start provider is located further from other plants, the generator may need to be larger (~300-350 MVA in size).

Prior to demonstration with confidence of alternative technologies (such as through Type 2 Transitional Services), it is likely that black start sources will need to be synchronous generating units – either new hydro or gas generation. AEMO encourages any party considering the deployment of a large (100 MVA+) synchronous generating unit to contact AEMO (nmas@aemo.com.au) and explore the opportunities to provide black start services.

Preliminary projections of system restoration requirements

AEMO has undertaken preliminary analysis against the Draft Determination of the SRS's Stage 2 restoration target of 50% of average underlying demand. This has then been used to estimate the potential scale of investment needed in equivalent firm capacity[63] to support system restoration in 2040, taking current announced coal closure dates (in most regions, this leaves only one coal station operating) and applying a safety margin equivalent to one or two large coal units being operationally unavailable[64]. While this equivalent firm capacity does not need to be black start capable to meet the Stage 2 target, there may be a prudent case to make some of these new investments black start capable to support meeting the Stage 1 target at low additional marginal cost.

For each region, the estimated equivalent firm generation capacity required was calculated based on the gap between what can be delivered by the 2040 supply curve without existing coal generation, assuming no new generation or storage capacity installed, and the Stage 2 target, shown in **Figure 14**.

In South Australia, although there are currently no major coal-fired generating units, AEMO has undertaken similar high-level analysis considering the impact of the announced retirement of gas units. Tasmania has not been assessed, as it has a large hydro fleet and there are no announced closures anticipated over the next 15 years.

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[63] Equivalent firm capacity (for example gas or hydro generation) refers to generation supply that needs to brought online progressively through the restart process to achieve the draft SRS's proposed Stage 2 restoration target. The values reflect the firm, dispatchable, and fully unconstrained capacity required over the minimum eight-hour system restoration period, noting that many generation and storage technologies in different locations can contribute to meeting this requirement with varied efficacy. Further, this additional capacity needs to achieve a reliability level above 95% to satisfy SRS requirements.

[64] In the 2024 Step Change scenario, where coal plants are projected to close much earlier than the announced coal closure dates, these system conditions and the requirements for equivalent firm capacity would occur much earlier.

Figure 14 Illustrative approach to forward analysis of NEM's ability to meet proposed Stage 2 restoration target

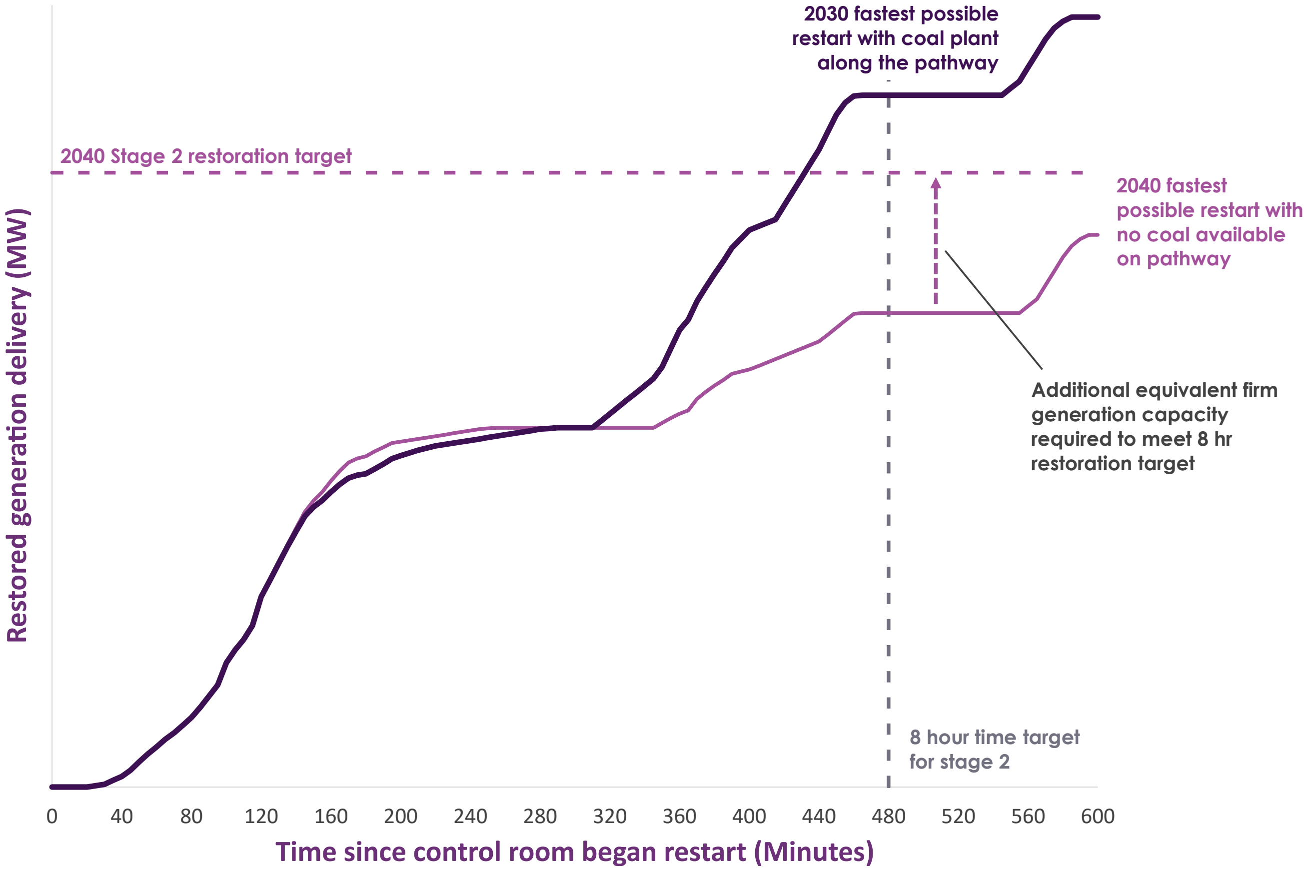

Table 11 shows the results of this preliminary assessment for each NEM region.

Table 11 Preliminary analysis results for additional equivalent firm generation capacity (MW) required to meet Stage 2 Restoration Target in 2040 based on publicly announced exit dates

	New South Wales	Queensland	South Australia	Tasmania	Victoria
50% forecast average underlying demand	6,000	5,300	1,450	N/A	4,400
Additional firm capacity required	1,300-1,800	1,600-2,100	1,150-1,550	N/A	700-1,200

These estimates represent upper bookend requirements expected to be progressively required over time, with the exact trajectory highly dependent on when stations become operationally unavailable either through decommitment or exit. While current assumptions treat these capacity needs as equivalent firm generation (for example, gas or hydro), future analysis will investigate the integration of storage and VRE using a probabilistic framework.

Additionally, some of the additional capacity could be met by committed and anticipated hydro and gas generation projects already in the pipeline, as well as new generation being projected by the ISP. However, given the location-specific nature of system restart pathways, the appropriateness of these projects to meet the identified requirements will depend on where they connect to the network, and needs to be assessed on a case by case basis.

This highlights the importance of integrated planning and co-optimised investment in both reliability and security needs to deliver the energy transition at least cost. An opportunity exists for new investment to meet both Stage 1 and 2 of the draft SRS by including black start capability on new synchronous generation. Investments made at initial project build would maximise the resilience of the future power system. To support this, regulatory and procurement frameworks will need to incentivise such investment for new generator builds. This approach would strengthen system restoration reliability, foster competition, and ultimately help drive long-term costs down for consumers.

AEMO intends to extend this preliminary analysis in 2026 by:

- exploring the application of a probabilistic approach to SRAS modelling to include more variable generation sources in the restart planning process to meet the Stage 2 restoration target, and
- signalling the locations within each region that are most suitable for black start capability.

Planning for future system restart approaches

In addition to supporting the regulatory review process, AEMO's *System Restart Technical Advice*[65] also outlined AEMO's latest thinking on the changes that need to be considered to support system restoration into the future. This was complemented by an independent consultant's report[66], commissioned by AEMO and other international system operators, reviewing international system restart practices, with a focus on system restart capability in the context of a power system with high contributions of IBR, and few synchronous generators.

Both reports highlight that in the design of future system restoration, opportunities exist to leverage the technological capabilities of IBR and new grid investments as traditional restart methodologies of building a strong synchronous generation island may not be feasible in a high IBR future. To realise these opportunities, additional work is required including technical analysis, trialling of new technologies, as well as evolution of the NEM's restart framework to potentially establish a post-transition restart methodology without large thermal generation. A coordinated plan across industry of testing, modelling, and timely, targeted investment is required to achieve this.

Where a retiring large thermal plant is on an existing restart pathway, its retirement presents opportunities (such as removing its requirement for minimum stable load) and new challenges (such as loss of the voltage support it provides during restart) that demand a balanced and forward-looking strategy. To develop a post-transition restart methodology for each NEM region and better understand transitional assessment requirements, industry collaboration is required to explore technological capabilities and investment opportunities. Over 2026, AEMO intends to commence engagement with OEMs and developers, explore additional practical trials using Type 2 Transitional Services, and continue AEMO's system restart investigation efforts to date. Future investment frameworks will also need to suitably incentivise investment in system restart, in both black start sources and restoration support services.

Finding new methodologies using other technologies or configurations (such as using a larger number of smaller gas and hydro stations), followed by practical testing of new proposed restart pathways, is imperative to build technical confidence and ensure sufficient investment in each region at least one year before it is required. This minimum lead time is driven by the need to prove and gain confidence in the new methodologies, and to mitigate the risk of early thermal plant decommitment, whether a deliberate market decision or due to plant failure.

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[65] See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/system-restart-technical-advice.pdf.

[66] See https://www.aemo.com.au/-/media/files/about_aemo/international-system-operator-collaboration/international-system-restoration-review.pdf.

8.2.3 AEMO's forward plan

AEMO's next actions to begin developing long-term and interim-term system restart methodologies include the following:

- Consultation on revised SRAS Guideline and progression of the 2027 SRAS procurement round. AEMO will also use near- and medium-term SRAS procurement rounds to assess required incremental changes to support existing restart pathways in the interim.
- Progression of procurement activities for Type 2 Transitional Services to demonstrate black start capability from IBR and support system restart under high DPV conditions.
- In 2026, AEMO will build on preliminary analysis to refine indicative SRAS capacity and locational requirements post-2030 to support restoration without reliance on coal units.
- Industry engagement with NSPs and participants to collaboratively investigate viable long-term system restart methodologies and investment opportunities.
- Working with the Reliability Panel and AEMC to support relevant reform efforts that help incentivise investment to support development of new SRAS sources and network assets (such as protection schemes, synchronous condenser and transformer design), and testing of potential restart methodologies along identified system restart pathways.

8.3 Management of power system frequency is evolving

Key messages

- BESS facilities have become the largest contributors of frequency control ancillary services (FCAS) in recent years, with strong potential to extend into inertia provision. With sufficient geographic diversity and coordinated control settings, increasing BESS capacity offers substantial frequency performance and stability benefits.
- BESS capacity distribution must be monitored to avoid overconcentration in a single NEM region, posing a risk of instability across the NEM's AC interconnectors for remote contingency events.

Key actions

- AEMO will continue to review and refine frequency control systems and their interactions, including automatic generation control, primary frequency response, and IBR droop settings.

8.3.1 Context

Power system frequency management has evolved significantly in recent years as the introduction of new frameworks and a shift in generation mix have enabled IBR to make increasing frequency control contributions. IBR, in particular BESS, have demonstrated the value that their rapid and tuneable frequency response capability can offer, contributing to overall lower costs for consumers.

8.3.2 Latest status

In 2025, AEMO published a *Technical Review of the NEM Frequency Control Landscape*[67]. This report summarised the evolving management of frequency and indicated the success of recent reforms in improving frequency control in the NEM. These reforms include:

- mandating primary frequency response (PFR) in 2020, substantially increasing the number of facilities that are tightly controlling frequency in the NEM,
- the introduction of Very Fast FCAS markets in 2023, which has been important in providing frequency control services as system inertia declines,
- development of an Inertia Network Services Specification[68] in 2024 to quantify the provision of synthetic inertia from IBR plant, and
- determining a NEM-wide inertia floor, stemming from the Improving Security Frameworks (ISF) rule of 2024.

Collectively, these reforms have greatly improved frequency performance in the NEM, reducing the number of excursions outside the Normal Operating Frequency Band and reducing the overall cost of FCAS procurement.

BESS provide largest FCAS contribution in the NEM

The growth of BESS-provided FCAS is shown in **Figure 15** with BESS delivering up to 90% of enabled FCAS[69]. Based on the volume of BESS under development or anticipated to commence development in the NEM, AEMO projects PFR and FCAS capability from BESS to increase up to five-fold by 2029, and expects this to support further improvement in frequency performance and reduced FCAS costs for consumers.

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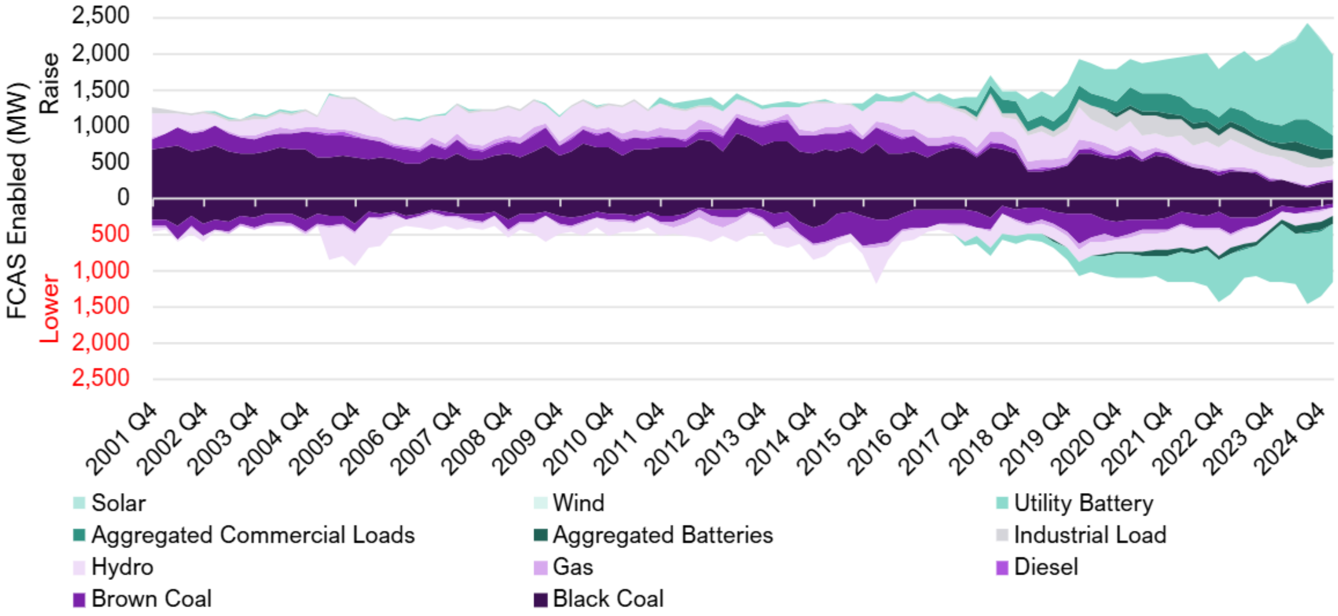
[67] At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/technical-review-of-the-nem-frequency-control-landscape.pdf.

[68] Published as schedule A of the *2024 Inertia Requirements Methodology*.

[69] AEMO (June 2025) *Technical Review of the NEM Frequency Control Landscape*, at https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/technical-review-of-the-nem-frequency-control-landscape.pdf.

Figure 15 FCAS enablement by technology type, 2001-2024 (MW)



The provision of inertia services is expected to follow a similar trajectory, with IBR anticipated to make major contributions in coming years as more synchronous generators are increasingly offline and stakeholders gain familiarity with the availability of synthetic inertia from GFM inverters (see Section 10.1).

BESS integration offers performance benefits, but requires NEM-wide capacity monitoring

AEMO's 2025 *General Power System Risk Review* (GPSRR)[70] investigated the risk and opportunities of increasing BESS capacity configured with aggressive frequency droop control settings. This investigation demonstrated that risk conditions can arise when BESS are concentrated within a single region, and remote non-credible frequency events trigger a PFR/FCAS response from a localised aggregation of BESS units. This introduces interconnector stability challenges when operating close to transfer limits, as the frequency performance of BESS exceeds that of local frequency control providers.

For large non-credible generation contingencies, modelling indicates this would result in large power swings across AC interconnectors, leading to voltage collapse or angle separation between regions in the most onerous cases. While the hypothetical risk of concentrated, aggressively tuned BESS was demonstrated in the 2025 GPSRR, AEMO found that the existing and planned grid-scale BESS facilities in the NEM are sufficiently distributed to mitigate the risk of rapid BESS frequency response in the short and medium term, and present an opportunity for improved power system dynamic performance.

8.3.3 AEMO's forward plan

Table 12 summarises how AEMO is monitoring and evolving frequency control as load and generation in the system continues to become more variable. This will require increased amounts of PFR-capable plant and FCAS reserves, much of which can be provided by BESS.

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[70] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-general-power-system-risk-review/2025-gpsrr.pdf.

Table 12 AEMO activities to monitor and evolve frequency performance

AEMO activity	Description
Review PFR settings	• Review enablement volumes and adequacy of regulation FCAS reserves and current PFR settings. • Develop pathway to finalise the implementation of PFR on semi-scheduled units, and implement any other changes recommended from the review of current PFR settings.
Technical Review of the NEM Frequency Control Landscape process	• Review aggregate generator frequency response to maintain power system security with increased IBR. • Trial basepoint adjustment in automatic generation control (AGC) and assessments of regulation FCAS for prolonged under-frequency correction. • Review interaction between PFR and AGC during contingency events to optimise system response.
AEMO will continue monitoring and will make adjustments if and when required	• Continue monitoring: – BESS developments throughout the NEM to ensure sufficient capacity dispersion and coordination of droop settings to mitigate the risk of stability issues owing to concentrated BESS frequency response. – Regional and individual unit distribution of FCAS procurement to avoid geographic and facility-level concentration. • AEMO will consider whether minimum amounts of any particular technology are required based on operational evidence. • The minimum droop setting allowed on IBR units was established in 2017 and is being monitored to ensure it remains fit-for-purpose as higher amounts of IBR generation operate in the NEM. • Aggregate generator frequency response represents a part of the supply demand imbalance that is not evident in the system frequency. AEMO will continue to monitor whether this response needs to be accounted for.

8.4 Challenges for protection and control systems

Key messages

- The power system is undergoing changes that may have significant impacts on the operation of protection and control systems.
- System fault levels must be maintained to ensure protections systems continue to operate correctly. Insufficient fault level provision from new infrastructure may require delay of decommitment and retirement of synchronous generators.
- Increasing size, number, and complexity of control schemes is contributing to maloperation and interaction risk in the NEM.

Key actions

- Pursue mitigation of minimum fault level risks around synchronous generation retirement/decommitment transition points as detailed in Part B.
- Undertake program of work to identify and manage risks associated with Remedial Action Schemes (RASs), as outlined in the 2025 GPSRR, including technical assessments and review of regulatory and RAS Guideline requirements.

8.4.1 Context

As the energy transition progresses, multiple assumptions upon which power system protection has been designed are subject to change. Further, network topology is evolving, and control schemes have become more numerous and complex. Risks of failure to operate correctly and of unexpected interactions are increasing.

8.4.2 Latest status

AEMO's 2025 GPSRR[71] highlighted a range of current and emerging risks associated with unexpected operation or interaction of protection and control schemes. Factors identified as having the potential to lead to cascading failure or major supply disruptions if left unmitigated were:

- changing fault levels due to the retirement or unavailability of synchronous generation,
- new transmission topologies,
- increasing number, size and complexity of control schemes, and
- lack of explicit requirements for RAS design.

The 2025 GPSRR highlighted that actions are needed now to mitigate growing risks of greater incidence and severity of scheme maloperation or interaction incidents. The report described these risks and identified further work, summarised below, to balance economical delivery of the energy transition, operability of the system, and acceptable risks.

Maloperation and interaction of protection systems and control schemes

Growth in the number and complexity of protection and control systems including RASs, as well as the larger size of events some newer schemes are designed to protect, all increase the risk and consequences of scheme maloperation and interaction, which have historically been low likelihood but high consequence events:

- More complex schemes are being adopted by new projects to reduce network investment and better utilise existing assets. However, complexity increases maloperation risks. Schemes need to be adequately designed, maintained and tested, and outage planning should be accounted for in scheme design, to minimise risk of maloperation.
- As the number of schemes increases, the likelihood of interaction increases, particularly for multiple schemes operating in close proximity or sharing common inputs. This in turn leads to risks of cascading failures.
- With schemes increasingly addressing larger non-credible contingency events (Section 8.5) and designed for large rapid responses, the consequences of maloperation become greater.

Despite such risks, there is no mandatory required approach that must be taken for the design of RASs, with the RAS Guidelines only indicating examples of good industry practice. There is no obligation for designers to comply with these guidelines. Information management, maintenance and testing of RASs also needs improvement to ensure the ongoing management of schemes is sustainable, and that RASs can be modelled accurately to capture and understand interaction risks.

8.4.3 AEMO's forward plan

Protection system considerations are incorporated in actions detailed in Part B to maintain system strength and minimum fault current levels at specific transition points for synchronous generation retirement and decommitment. To address risks specific to RASs AEMO outlined a broad work program in Section 2 of the 2025 GPSRR, which included:

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[71] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-general-power-system-risk-review/2025-gpsrr.pdf.

- investigation of RAS modelling requirements for RASs in the NEM and best practice across other network operators. AEMO to update power system models to more easily include an improved representation of remedial action schemes, including UFLS – see Part A Section 1.3.3,
- in consultation with industry, expansion of the RAS Guidelines into explicit requirements,
- review of the NER clauses relevant to RASs, potentially leading to a rule change request, and
- detailed studies conducted by AEMO on RAS unexpected operation.

8.5 Increasing risks of non-credible contingencies

Key messages

- Changes in grid topology and connected assets may increase the risk and severity of non-credible contingencies, requiring new approaches to their management.

Key actions

- AEMO continues to complete detailed studies and analysis on the management of non-credible contingencies in the current and future system to understand the emerging risks of cascading failure or major supply disruptions, and approaches to mitigating these risks.

8.5.1 Context

Large amounts of new generation are connecting as the energy transition progresses. Non-credible contingency risks may increase where generation is concentrated behind common assets that could fail under rare circumstances.

8.5.2 Latest status

AEMO's 2025 GPSRR identified a range of factors which could increase the size, number and impact of non-credible contingencies, requiring enhanced management approaches:

- concentration of large volumes of new generation behind existing or new long double circuit transmission lines or substations may increase the size of non-credible contingencies such as loss of both lines or circuit breaker failures,
- high DPV contributions expose a larger volume of supply to shake-off risks after a non-credible contingency causing a significant voltage disturbance,
- increased weather-driven impacts such as bushfires, storm and lightning on transmission lines carrying higher power flows over a larger geographical footprint,
- fewer synchronous generators providing system security services such as system strength or inertia increase exposure to system security risks following non-credible contingencies that trip or isolate these remaining providers from parts of the network, and

- increasing connection of large inverter-based loads such as data centres (Section 10.3) potentially increasing load contingency sizes and sensitivity to system disturbances, for example large voltage-sensitive loads suddenly transferring to backup power supplies.

8.5.3 AEMO's forward plan

AEMO's Draft 2026 GPSRR Approach Paper[72] outlines the quantitative analysis that AEMO plans to undertake to assess risks related to increasing non-credible contingencies. This assessment is intended to quantify the range of contingency sizes that may pose risk of cascading failure or major supply disruptions and to demonstrate the effectiveness of potential mitigation measures. Large non-credible contingencies are proposed to be considered under the 2026 GPSRR as follows:

- PSS®E studies will be undertaken to assess the impacts of increasing non-credible contingency sizes in each region for historical and future cases.
- PSS®E sensitivities will be completed on the effectiveness of mitigation measures such as increased FCAS, non-credible contingency size limits, RASs, protected events and emergency frequency control schemes (EFCS).

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[72] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2026-gpsrr/2026-gpsrr-approach-paper-draft.pdf

9 Distribution level developments

Distributed energy resources (DER), including consumer energy resources (CER), are making increasingly significant contributions to the power system. AEMO is collaborating with stakeholders to harness the opportunities, and manage challenges, of DER with respect to system security in a zero- or near-zero-emissions power system.

This section discusses the work being undertaken to maintain system security in response to developments in the distribution system, and growth in DER/CER[73], including:

- the growing contribution and impact of DER on system security and plans to manage this, and
- challenges and opportunities for system security associated with the rapid growth in demand side participation (DSP) anticipated over the next 10 years.

9.1 Operating the NEM with high levels of distributed resources

Key messages

- CER are becoming increasingly central to system operation, and AEMO is taking steps to continue to encourage CER growth and ensure households and businesses can continue to have a meaningful impact on Australia's energy transition.
- Minimum operational demand continues to decline across all NEM mainland regions, driven by strong consumer uptake of DPV. This is projected to continue over the next five years, resulting in increased incidence of demand below minimum system load (MSL) thresholds.
- MSL thresholds will reduce over time as system security is decoupled from synchronous thermal generating units.
- There is significant opportunity for active management of DPV and other DER, greater load flexibility, and storage to increase demand at times of high DPV generation – both on a daily basis as well as under challenging system conditions.
- Enhanced coordination across distribution and transmission is required to host and securely manage continued growth in DPV. Active DPV management capability, starting with an effective emergency backstop, that scales as DPV continues to connect, is critical for managing MSL and other DPV-related system security risks that may emerge.
- Longer term, additional factors are likely to affect the technical envelope of the power system as DPV contributions increase. These factors are complex and have not been traditionally considered in transmission and bulk power system adequacy studies and require concerted focus now.

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[73] DER means generation, storage, and flexible load resources connected to the distribution system; it includes CER, which are resources owned or operated by energy consumers at their home or business.

Key actions

- AEMO is continuing to collaborate closely with DNSPs and TNSPs on functional requirements for securely and reliably operating a high-DER power system, and the necessary capability evolution required.
- DNSPs and governments to continue prioritising effective implementation of, and compliance strategies for, emergency DPV backstop mechanisms and consider opportunities to increase demand within their networks under MSL conditions, within their broader DER/CER integration plans.
- AEMO is working with market bodies, governments and industry through the National CER Roadmap on operational roles and responsibilities, and the data sharing required across actors for a high-DER power system, including for managing system security.
- AEMO is seeking opportunities to collaborate with TNSPs and DNSPs, the research community and broader industry on the activities required to understand emerging high-DPV issues anticipated over the next 5-10 years.

9.1.1 Context

Australia is a world leader in the uptake of DER, primarily driven by the uptake of DPV[74] over the last 15 years, from fewer than 100,000 systems in 2010 to more than 4 million today. This has played a major role in the decarbonisation of Australian energy systems. As per AEMO's 2025 *Inputs, Assumptions and Scenarios Report* (IASR) *Step Change* scenario[75], AEMO projects DPV to grow in the NEM over the coming 10 years, from about 25 GW installed today, to 35 GW by 2031 and 43 GW by 2035. This highlights the continuing value of DPV in supporting a low- or zero-emissions power system.

In addition to DPV, **Table 13** shows anticipated growth in other significant resources connecting to the distribution system, raising opportunities and challenges for managing system security (see Sections 9.1.2, 9.1.3 and 9.2).

Table 13 AEMO demand side projections, 2025 IASR *Step Change* scenario

Component		2026	2031	2036
Rooftop PV (<100 kW)	*Capacity, GW degraded*	25.1	34.9	42.5
PV non-scheduled generation (100 kW to 30 MW)	*Capacity, GW degraded*	1.9	3.3	4.8
Other non-scheduled generation	*Capacity, GW*	1.0	1.0	1.0
Electric vehicles	*Annual energy, TWh*	0.9	7.0	17.7
Data centres	*Annual energy, TWh*	4.7	14.3	22.9
Electrification	*Annual energy, TWh*	0.2	9.3	28.0
Embedded energy storages	*Capacity, GW*	2.2	5.9	9.8

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[74] DPV, sometimes referred to as distributed solar, refers to grid-connected solar capacity not part of AEMO's central dispatch. This includes residential and commercial rooftop PV and larger non-scheduled PV systems embedded within the distribution networks.

[75] AEMO, 2025 *Inputs and Assumptions Workbook*, 28 August 2025, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

9.1.2 Latest status

Based on operational experience with increasing uptake of DPV in the NEM, AEMO has developed a set of functional requirements for securely and reliably operating a high-DER power system. Their current status is summarised in **Table 14**. AEMO is collaborating with DNSPs and at the policy level through the National CER Roadmap on the technical capabilities, roles and coordination required to securely and reliably operate a high-DER power system[76].

Table 14 Functional requirements for operating a high-DER power system and current status

Area	Importance for operation of the transmission system	Current status
Visibility and predictability	Required for both long-term and short-term system security planning, and for effective operational response to the range of plausible system conditions.	Ongoing priority to improve DER Register data quality. AEMO has validated data against other sources (such as Clean Energy Regulator data for the Small-scale Renewable Energy Scheme) but issues remain with some fields. Currently considering data gaps and how they can be resolved. These include mode of operation, tracking upgrades and retirements, and inconsistent data on BESS installations. AEMO has processes in place to map registered installed devices to the transmission network load points. Currently engaging with DNSPs on more robust, standards-based approaches. AEMO is collaborating with industry on electric vehicle (EV) data requirements for distribution network, system and market operations, including data collection and estimating EV charging load[A]. Exploratory work with DNSPs on AEMO operational forecasting visibility and predictability of DNSP actions impacting net load at the Transmission-Distribution (T-D) interface, starting with a collaboration with SA Power Networks on Flexible Export Limits and emergency DPV backstop activation.
Performance during disturbances	Appropriate standards for the DER fleet and managing the risk of sympathetic tripping of inverter-based systems following grid disturbances.	Continuing improvement in compliance of inverters to AS/NZS4777.2:2020 requirements. 80-90% of newly installed systems configured with the correct grid code[B] with an amendment to the standard in 2024 including labelling of obsolete versions in menu selections. Disturbance ride-through behaviour in >30 kilowatts (kW) systems needs further improvement. Requirements for DER connections not covered by AS/NZS4777.2:2020[C] included in AEMO's Guideline for sub 5 MW DER connections. AEMO updated composite load and DER models in June 2024, and validated models through system events in June 2025, to better represent transient behaviours that influence stability limits. AEMO is working with TNSPs on the implementation of these models[D].
Emergency DPV curtailment	Ability to disconnect a sufficient volume of DPV generation, if required to maintain system security	Emergency backstop requirements are in place in South Australia and Victoria, partially in place in Queensland, and in preparation in New South Wales for a 2026 commencement. In Queensland, systems below 10 kilovolt amperes (kVA) are currently exempt. AEMO strongly recommends including all systems in emergency backstop requirements and has identified this as an unresolved issue for Queensland in Part B of this report. Uplift in response rate and capacity, clear performance expectations and testing, and compliance processes – with associated governance arrangements – are required for effective emergency backstop mechanisms. See Part B for regional assessments. Emergency control requirements for DER connections in the 200 kW to 5 MW range included in AEMO's Guideline for sub 5 MW DER connections.
Voltage management	Managing the impact of DER on transmission network voltage control, and coordination required with the distribution system for optimal outcomes across the system.	Actively being considered in TNSP-DNSP planning with some inconsistency in requirements at the T-D interface and how this is considered in joint planning. AEMO and TNSPs are continuing to monitor voltage and reactive power exchange at the transmission-distribution boundaries. Further work required to determine the kinds of contingencies that need to be considered, especially in the high-DER context.
DER scheduling and	Effective scheduling of DER in system balancing and congestion management, with appropriate coordination	All NEM DNSPs are currently implementing, or intending to implement, flexible export arrangements. Distribution-level local services and flexibility platforms, aiming to harness and manage DER for local network support, are an emerging area being considered in DNSP trials.

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[76] See for example: https://consult.dcceew.gov.au/national-cer-roadmap-redefine-roles-m3-p5.

Area	Importance for operation of the transmission system	Current status
operational coordination	between market participation, distribution limits, and transmission network security.	AEMO is currently consulting with industry on the implementation of the new Voluntarily Scheduled Resource (VSR) framework for price-responsive energy resources to participate in NEM scheduling and dispatch processes, commencing in May 2027[G].
Manage cyber security compromise	Managing risk of cyber compromise of DER devices and management systems, securing data-in-flight and network practices, and ability to monitor, detect, isolate and defend mass compromise events.	Standards Australia, working with the Federal Department of Climate Change, Energy, the Environment and Water (DCCEEW), is considering DER cyber security standards, including device-level requirements for interactions with DPV and BESS inverters, demand response and EV chargers, through several ongoing processes. The *Australian Energy Sector Cyber Security Framework* is a voluntary self-assessment tool for market participants to assess cyber security maturity and may be used to support meeting obligations under the *Security of Critical Infrastructure Act 2018*[H]. DNSPs are using the framework to develop requirements for DER OEMs and customer agents, interacting with their servers. Work is underway to establish Public Key Infrastructure (PKI) enabling secure communication between DNSP systems and DER devices, prior to the NSW-ACT emergency backstop implementation in 2026[I].
System restart with increasing DPV	Managing the impact of increasing DPV generation on the system restart process, including ability to understand and model the impact and management measures in place.	AEMO has been assessing system restart arrangements for all NEM regions, identifying challenges with the impact of DPV on stabilising load, discussed further in Section 8.2 AEMO has published a Statement of Need for Type 2 Transitional Services to support restart during high-DPV conditions[J].
Emergency frequency control with increasing DER	Managing the impact of increasing DER on emergency frequency control, including ability to understand and model the impact and management measures in place.	AEMO has collaborated extensively with DNSPs on the adequacy of NEM underfrequency load shedding schemes (UFLS) with increasing DPV impact and mitigation measures[K]. The current priority is coordination required with DNSPs for real-time visibility of load on UFLS relays and updating UFLS schedules to reflect actual UFLS availability. AS/NZS4777.2 has included frequency deviation and RoCoF withstand requirements, as well as active power support for extreme frequency events since 2015, formalised and enhanced in the 2020 version.

A. For latest updates, see AEMO, Electric Vehicle Data, at https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/electric-vehicle-data.

B. AEMO, *Compliance of Distributed Energy Resources with Technical Settings: 2025 Update*, 10 September 2025, at https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/compliance-of-der-with-technical-settings.

C. The coverage of AS/NZS4777.2 was changed following the 2024 revision to AS/NZS4777.1 to remove the 200 kW threshold and explicitly apply to low voltage (LV)-connected inverter energy systems only. Standards Australia, AS/NZS 4777.1:2024 Grid connection of energy systems via inverters, Part 1: Installation requirements, at https://www.standards.org.au/standards-catalogue/standard-details?designation=AS-NZS-4777-1-2024.

D. For reports and ongoing updates, see AEMO, Power system model development – Power system models for DER and load, at https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/power-system-model-development.https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/power-system-model-development.

F. AEMO, *Learnings from industry implementation of emergency backstop mechanisms for distributed resources*, July 2025, at https://www.aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/learnings-from-industry-implementation-of-emergency-backstop.pdf.

G. AEMO, Voluntarily Scheduled Resources Guidelines consultation, at https://www.aemo.com.au/consultations/current-and-closed-consultations/voluntarily-scheduled-resources-guidelines-consultation.

H. AEMO, Australian Energy Sector Cyber Security Framework, at https://www.aemo.com.au/initiatives/major-programs/cyber-security.

I. ARENA, National Energy Public Key Infrastructure Project (NEPKI), at https://arena.gov.au/projects/national-energy-public-key-infrastructure-project-nepki/.

J. AEMO, Statement of Need – System Restart under high DPV conditions, October 2025, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/system-restart-under-high-dpv-conditions-service.

K. For reports and ongoing updates, see AEMO, *Adapting and managing under frequency load shedding at times of low demand*, at https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/adapting-and-managing-under-frequency-load-shedding-at-times-of-low-demand.

Minimum system load challenges

MSL is the key challenge with respect to the aggregate impact of DPV on the bulk power system. Periods of MSL occur when distributed generation, particularly passive rooftop PV, significantly reduces demand on the transmission system. Large-scale synchronous generators are currently essential for delivering system security services, such as system strength, fault current, inertia, voltage control, and ramping. These synchronous generators need to operate at or above their minimum stable operating levels (MSOLs). Low operational demand may prevent dispatching enough large-scale generators to maintain system security.

To support MSL management, AEMO introduced the MSL framework, summarised in **Table 15** below. It aims to mirror the existing Lack of Reserve (LOR) framework used for low supply reserve conditions.

Table 15 Minimum system load framework

Level	Definitions	AEMO actions
MSL1	Demand is two credible contingencies away from MSL3	Monitor the situation. Publish MSL notice with MSL thresholds when forecasted, which can be up to a week ahead.
MSL2	Demand is one credible contingency away from MSL3	Take available actions to clear the MSL2 condition if possible. Take actions required to land satisfactory and return to and remain secure within 30 minutes following a credible contingency.
MSL3	Forecast demand is insufficient to maintain a secure operating state	Additionally, instruct NSPs to maintain regional demand above the MSL3 threshold.

All NEM mainland regions have passed minimum demand thresholds which would require actions to maintain system security under some conditions.

Regional MSL assessment

AEMO currently manages system security issues under MSL conditions on a regional basis, based on the conditions in the specific region at the time, accounting for conditions in neighbouring regions. All NEM mainland regions are demonstrating consistent and continuing decline in minimum demand leading to an increased potential incidence of operational demand falling below MSL thresholds.

Each region is implementing measures aimed at lowering these thresholds (including reducing dependence on synchronous thermal generating units) and increasing operational demand at relevant times (via actions such as load shifting or active PV management). AEMO evaluates regional MSL outlooks based on both onerous and system normal conditions:

- Under system normal conditions, if power station exits and network investments in essential system services proceed as planned, and there is enhanced flexibility from CER to manage output in the middle of the day, no MSL3[77] conditions are forecast to occur in any region. However, if there are delays, actual MSL3 events could occur in all regions by 2028-29.
- Under rare, but plausible, onerous conditions (for example, a combination of significant load outages, network outages, and/or islanded regions), there are varying levels of available capability to increase operational demand in the near term. There remains an urgent need for increased emergency distributed PV backstop capacity, particularly in Queensland, to maintain system security and avoid widespread customer impacts. In the onerous condition modelled for Queensland, current capabilities, including selectively shedding the most impactful reverse-flow feeders, may still be insufficient to maintain system security. In Victoria and New South Wales/Australian Capital Territory, some extreme low probability but onerous scenarios may require reverse-flow feeder shedding. South Australia is projected to have sufficient capability to manage both typical conditions and possible onerous system conditions.

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[77] MSL3 events are those in which action needs to be taken to increase operational demand to maintain system security, which may include emergency backstop mechanisms to reduce distributed PV generation. See Part B and Appendix A3 for further details.

Further detail about how AEMO manages MSL conditions and assessment for each NEM mainland region is in Part B and Appendix A3, including a description of the types of onerous conditions considered in each region.

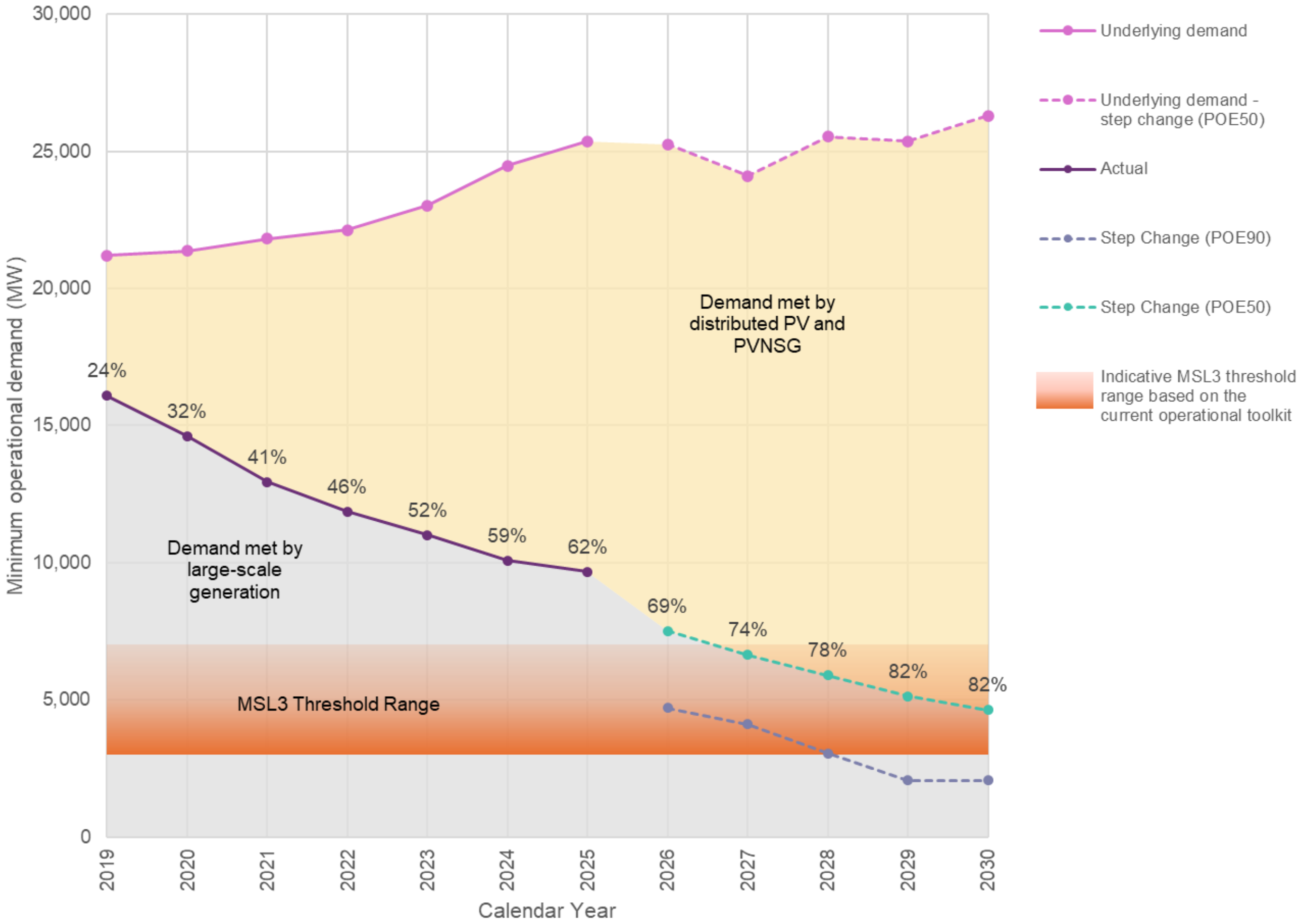
NEM-wide MSL

Beyond regional MSL challenges, the coincidence of low demand and high DPV conditions across regions is projected to result in multi-region or NEM-wide minimum demand conditions. Operationally challenging situations may emerge for the NEM mainland within the next 12 to 18 months under some low probability, but plausible, onerous system conditions, such as prior outage conditions or with significantly reduced interregional transfer capacity.

AEMO estimates that the minimum operational demand the NEM can currently support is indicatively in the range of 4-7 GW, under the present operational toolkit and MSOLs of synchronous generating unit combinations required for system security today.

Figure 16 shows historical and forecast NEM-wide minimum operational demand levels against this indicative threshold range.

Figure 16 Historical and projected minimum operational demand against indicative MSL3 threshold range for the NEM (2025 ESOO *Step Change* scenario)



MSL conditions are managed on a region by region basis, based on individual regional system conditions. The NEM-wide range indicates where there is a likelihood of MSL3 conditions emerging in one or multiple regions. If MSL conditions arise in one or multiple regions, AEMO may need to take action, based on individual regional system states and operating conditions, to restore demand to secure levels to mitigate the risk of widespread and prolonged outages if credible contingencies were to occur (see Appendix A3 for further details). AEMO is continuing to collaborate with NSPs and market participants on procedures, processes and frameworks to improve management of MSL conditions.

A high DPV scenario in 2031

AEMO has developed a power flow case and undertaken steady state analysis and screening studies for a NEM-wide high DPV scenario, plausible within the next 5-10 years, supplementing the regional assessments summarised in the regional outlooks in Part B. The NEM-wide study allows consideration of coincident high DPV across regions, how supply-demand balance is achieved and the implications of any inter-regional transfer limits. Study assumptions were consistent with system security planning studies in Appendix A3[78]. These are the key findings and implications of the study:

- The location of future electrification load will have a large influence on network flows under high DPV conditions. There may be voltage stability and other limits restricting power transfer from DPV centres to remote industrial load centres in the transmission system.
- Voltage and fault level screening analysis findings were largely consistent with current AEMO and TNSP planning, with identified issues anticipated to be addressed by planned network development[79]. Further work is required to plan for higher levels of DPV online[80], noting that this distribution system consideration can be considered between AEMO, TNSPs and DNSPs as a joint planning matter.
- Desktop analysis of large load contingency scenarios suggests there is sufficient active power headroom available across interconnectors and from the projected utility-scale BESS fleet to respond to a sudden supply-demand imbalance arising from loss of the largest load online. This capacity will need to be proactively managed in the lead up to forecast MSL periods, on a pre-contingent, anticipatory basis.

9.1.3 AEMO's forward plan

This section outlines priority actions for managing system security under MSL conditions and the investigations required to consider and support increasing levels of DPV as uptake continues over the next 5-10 years.

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[78] Including future network development and the anticipated synchronous generation and BESS fleet, with synchronous generation dispatch set to the minimum synchronous unit combinations online in each of the mainland NEM regions simultaneously.

[79] Including synchronous condenser deployments, reactive support and committed/anticipated major inter- and intra-regional transmission projects.

[80] DER inverters need a stable voltage waveform to synchronise with the grid and remain connected under plausible disturbances. Sufficient fault level is required in the distribution network for current-based protection schemes to operate effectively. Large volumes of grid-following DER inverters and their fault current contributions can impact the selectivity and sensitivity of protection schemes. The inter-relationship between fault level requirements at transmission level and the local fault current impacts of DPV, for maintaining protection quality fault current at the distribution level, needs further investigation.

Managing MSL risks

Strategies for managing MSL risks[81] involve both forward planning and operational considerations, summarised in **Table 16** below and explained further in this section.

Table 16 Strategies to manage minimum system load

Strategy	Planning considerations	Operational capability
Reduce the amount of generation required online to maintain security	System changes and network investments reducing the minimum supportable load needed to accommodate synchronous generation unit commitment for system security.	MSL thresholds are dynamically determined by the number of thermal units online at the time, network configuration and operational risk. Operational measures available when an MSL2 event is forecast can reduce the MSL thresholds, potentially avoiding actual MSL2 or MSL3 events[A]. These include recalling network outages, or decommitting non-essential coal units.
Better utilising DPV generation via energy storage and increasing daytime demand	Enabling and incentivising load and storage flexibility over different time horizons: • on a daily, system normal basis, • via Transitional Services, and the related learning that may help inform future market reforms, or • as part of emergency backstop measures. These can be encouraged multiple ways, including market, tariff and community-based arrangements.	Load and storage flexibility soaking up DPV generation on a daily basis would contribute to increasing system load in the daytime. Today, in Victoria, AEMO is able to direct or utilise contracted BESS via Type 1 Transitional Services contracts, when an MSL2 event has been forecast, to be available to resecure the system by charging following a credible load contingency. Further procurement is being explored for other regions. Longer term, there is potential to develop services to optimise charging profiles to meet participant needs and system security requirements. Some DNSPs can increase demand as an MSL3 action, including controlled load hot water, network controlled batteries, or enhanced voltage management.
Decrease non-essential generation	DNSP implementation of: • active DER management capability on a daily basis, including flexible export arrangements for DPV, and/or • emergency DPV curtailment schemes covering new systems and associated performance requirements.	Integration of DNSP active DER management capability with pre-dispatch to reduce aggregate DPV generation if an MSL2 condition has been forecast. Curtailing DPV generation online if needed during an actual MSL3 condition.

A. For an explanation of the MSL framework, see Appendix A4, or AEMO's factsheet at https://www.aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/2025-spring-and-summer-minimum-system-load-thresholds-fact-sheet.pdf.

Reduce the amount of generation required online

MSL thresholds reflect the operational demand required to match required levels of synchronous generation. At their lowest level, these thresholds reflect the minimum synchronous generating unit combinations required for system security, with each unit operating at their MSOL.

Over time, MSL thresholds are expected to reduce as synchronous thermal generating units reduce their MSOL, decommit and exit, however this is predicated on investment in other sources of essential system services keeping pace with these changes, particularly the installation of synchronous condensers. Specific implications for each region are in Part B.

The flexibility of thermal units (discussed in Section 8.2) will be increasingly important for managing MSL risks, via reduction in MSOLs or more regular decommitment. AEMO works closely with market participants on operational decisions to decommit thermal units, considering factors including:

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[81] AEMO, *Supporting secure operation with high levels of distributed resources: Q4 2024*, December 2024, at https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/managing-minimum-system-load.

- the stable technical envelope and network configuration, including FCAS requirements, voltage control, reserve adequacy, the units' minimum safe operating level, and the units' return to service time, and
- operability and technical limitations of plant to meet adequacy requirements for the evening peak, including the MSOL of units and return to service times.

In the future, when replacement essential system services have enabled the system to run at times without any synchronous generation, observance of MSL thresholds will nevertheless be a continuing requirement, to ensure overall supply and demand balance and interregional transfer limits can be met.

Energy storage

Significant storage capacity, both large-scale and small-scale, is being added to the NEM, with 26 GW of BESS in the connections pipeline as of September 2025[82]. The Federal Government's Cheaper Home Batteries program supports discounted upfront costs for eligible small-scale BESS (5 kilowatt hours [kWh] to 100 kWh) connected to DPV systems[83]. Energy storage has the potential to assist during future high DPV scenarios in several ways:

- charging, thereby drawing active power from the system, effectively soaking up DPV generation,
- maintaining charging headroom in reserve to provide contingency response if a load contingency were to occur,
- reducing state of charge prior to forecast MSL events, to enable a longer response,
- providing dynamic reactive support to assist with voltage control, particularly for lightly loaded transmission paths, and
- providing GFM capability and associated system services.

Careful consideration is required of the range of capabilities that storage can provide and how its available capacity is configured and coordinated as DPV uptake progresses and storage is increasingly relied upon for different uses. It is possible that the most efficient use of BESS is on a daily basis to assist with balancing supply and demand while maintaining headroom to support ongoing variability and recovery from credible contingency events – rather than reserving additional headroom for rare onerous conditions.

Implementation of the new Voluntarily Scheduled Resources framework (discussed in Section 9.2.3) provides a participation pathway for aggregated resources, including small-to-mid-scale storage assets, to better align with and respond to system needs. While there is expected to be sufficient BESS capacity to support MSL management in most typical conditions, this capacity is not guaranteed to be available with sufficient certainty to fully support system security under more onerous conditions.

In the absence of better integration between market signals and security needs, directions and/or constraints may be required on BESS in the pre-dispatch horizon to manage state of charge for availability during MSL periods. As discussed in Part A Section 2.3, AEMO has issued Statements of Need to enable procurement of Type 1 Transitional Services to help manage forecast MSL conditions and Type 2 Transitional Services to trial innovative approaches to inform future MSL

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[82] AEMO, *Connections Scorecard – September 2025*, 27 October 2025, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard.

[83] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.

management. In some cases, DNSP-controlled batteries can form part of a response to increase operational demand in response to MSL events.

The AEMC is also considering a rule change proposal from the Clean Energy Council (CEC) to establish an MSL reserve service. This presents another opportunity to consider ways to best align participant interests and system requirements when managing MSL events.

Increasing daytime demand

AEMO's 2025 IASR *Step Change* scenario includes significant growth in data centres, business load, large industrial loads, and industrial electrification, moderating the decline in minimum demand, particularly in later years. This uptake is uncertain, relative to the projected uptake of DPV, but could be of system value in the 5-10 year horizon, using surplus DPV generation as well as expanding the pool of available flexibility to manage system security if abnormal conditions occur.

Incentives and participation pathways to shift demand to high-DPV periods are also being considered and implemented today. The development of the system architecture for operational coordination required across parties is critical for enabling and supporting this direction.

DNSPs' capabilities as DSOs (described further in Section 9.2.3), and retailer actions, can also provide flexibility and improved outcomes at the system level. These include:

- controlled load capability, including electric hot-water heating during the daytime, as well as load shifting to peak solar hours, and
- short-term load-turn up opportunities, including for controlled load hot water (these capabilities are included in the emergency backstop capacity estimates in Part B).

The AEMC's pricing review[84] is considering the alignment of network tariffs, retail pricing, and system needs. This may include facilitating load shifting, including electric vehicle charging, to low-cost times during peak solar hours. The Federal Department of Climate Change, Energy, the Environment and Water (DCCEEW) and the AER are currently consulting on the inclusion of a Solar Sharer option within the Default Market Offer, requiring eligible retailers to offer plans with free usage during a 3-hour window in the middle of the day[85].

While these capabilities are intended to manage distribution network loading and utilisation of DPV generation on a daily basis, they can also be of significant value at the system level by increasing daytime system load.

The Transitional Services discussed above will also consider opportunities for temporary increase from commercial and industrial load during MSL events.

Decrease non-essential generation

AEMO's MSL procedures include the use of directions to reduce large-scale generation that is not needed for system security at the time of the MSL event. This includes wind and solar farms that have not already reduced their output for

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[84] AEMC, *The pricing review: Electricity pricing for a consumer-driven future*, at https://www.aemc.gov.au/market-reviews-advice/pricing-review-electricity-pricing-consumer-driven-future.

[85] For retailers in New South Wales, South Australia and south-east Queensland. See DCCEEW, *Consultation on reforms to the Default Market Offer*, at https://consult.dcceew.gov.au/consultation-on-reforms-to-the-default-market-offer. The AER is concurrently consulting on how it would calculate the Solar Sharer Option for the 2026-27 Default Market Offers; see AER, *Default Market Offer 2026-27*, at https://www.aer.gov.au/industry/registers/resources/reviews/default-market-offer-2026-27.

economic reasons. If all the above have not resolved the MSL condition, DNSPs may have to take actions to increase operational demand, including use of emergency backstop capabilities to reduce the output of DPV.

The status of DNSP emergency DPV backstop mechanisms is summarised in Part B and Appendix A3. AEMO has also reported on *Learnings from industry implementation of emergency backstop mechanisms for distributed resources*[86]. AEMO will continue to work with policy-makers, governments and NSPs towards:

- extending emergency DPV backstop arrangements to cover all new and upgraded DPV systems in all NEM mainland regions, and
- improving the performance and effectiveness of backstop implementations, uplifting conformance assessment and establishing at-scale testing.

Longer term, the National CER Roadmap workstreams[87] are working to formalise relevant roles and responsibilities. As part of the workstream consultations, AEMO has supported assigning DNSPs to the roles of DSOs and including system security responsibilities in those roles. AEMO has also supported formalising roles for customer agents and communication managers, which are also necessary for effective emergency curtailment mechanisms.

High DPV studies

Table 17 summarises the potential implications of increasing DPV uptake with respect to the preconditions for securely and reliably operating the power system.[88] This has identified issues that need to be investigated and better understood to allow the technical envelope of the power system to accommodate the very high levels of DPV projected to be online over the next 5-10 years.

DNSPs and TNSPs need to consider and evaluate potential risks well ahead of time to formulate the limits advice required for AEMO to develop constraints and manage DPV-related risks operationally. Many of the issues are highly complex and their assessment will require new methods and tools as well as time to build understanding.

This uncertainty, if unaddressed, could lead to more conservative operational processes being used to manage system security as DPV uptake continues. System operators, NSPs, and research groups in Australia and internationally recognise the need for new methods and tools to assess the stability and dynamics of high DER power systems[89]. AEMO continues to work with these stakeholders to prioritise and complete the recommended further investigations over the coming years[90].

Priority areas for consideration over the next year include:

- TNSP utilisation of AEMO composite load and DER models, and EMT studies to account for the impact of DPV momentary cessation on transient stability,
- BESS delivery of very fast frequency response and how this interacts with managing MSL risks, and

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[86] See https://www.aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/learnings-from-industry-implementation-of-emergency-backstop.pdf.

[87] In particular, the workstreams on *Redefine roles for market and power system operations – M3/P5* https://consult.dcceew.gov.au/national-cer-roadmap-redefine-roles-m3-p5 and the *National Technical Regulatory Framework – M2* https://consult.dcceew.gov.au/natl-cer-roadmap-tech-priorities-consult.

[88] Preconditions are as outlined in AEMO, *NEM Engineering Roadmap to 100% Renewables*, December 2022, at https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap/reports-and-resources.

[89] Including transmission-distribution co-simulation approaches, application of composite load and DER models, EMT simulation, impedance scanning techniques, quasi-dynamic time series analysis and cyber-physical systems modelling.

[90] Interested parties can write to FutureEnergy@aemo.com.au.

- weak grid scenarios in the distribution network and implications for DER inverter stability, including feasible methods to screen for this risk.

System snapshots and base cases developed for AEMO's high DPV scenario study can be extended to assess a range of issues. This requires model and case development in different simulation domains, approaches to represent distribution networks, and load and DER dynamics to be applied to future NEM cases and scenarios. AEMO is engaging with other system operators, TNSPs and DNSPs, vendors and experts in the methods and simulation approaches necessary to undertake these high DPV investigations in the NEM context.

Table 17 Scan of potential high DPV implications and investigations required

System criteria		High DPV implications	Investigations required
Frequency and inertia	Ability to keep system frequency within defined limits following credible and non-credible events, including RoCoF containment and effective emergency frequency control arrangements.	Reducing frequency-responsive plant online during high DPV conditions.	Active power headroom requirements for available BESS; network capacity to support contingency FCAS delivery from BESS.
		Impact of storage, electrification and new large loads on credible load contingency.	Plausible sympathetic tripping and related common-mode risks for emerging load categories.
		Potential sympathetic tripping of data centre loads largely located close to large DPV generation clusters in Sydney and Melbourne, discussed in Section 10.3.	Local power flows, stability and frequency impacts.
Transient and oscillatory stability	Appropriate stability limits in place for projected reductions in operation of synchronous machines.	Momentary cessation of DPV inverters post-fault resulting in fault-induced delayed voltage recovery following disturbances[A].	Impact on the transient response of the power system during major contingencies.
	Appropriately damped local and inter-area oscillation.	Potential for new oscillation modes with less synchronous generation online during high DPV periods.	Oscillation modes under plausible dispatch conditions, accounting for damping and power system stabiliser (PSS) capability of BESS IBR and synchronous condensers.
		Closed loop controls intended to actively manage DPV and DER and network assets in the distribution networks can result in oscillatory behaviours and unpredictable responses due to multiple uncoordinated controls interacting in conflicting ways[B].	Time sequential simulation of cyber-physical interactions that could lead to material instabilities at scale and feasible mitigations.
System strength	System strength requirements met by alternatives to system configurations that require minimum loading on synchronous fossil fuel generators.	Oscillations between grid-following DER inverters in the distribution network, and between these inverters and the network flows and controls[C].	Dynamics of DER, load and the distribution network in plausible high DPV, low underlying load scenarios.
		Performance of DER under weak grid conditions[D] and fault current requirements for DER inverters to remain synchronised during faults.	Impact of very high DPV clusters on fault current in the distribution network against requirements for effective local protection. Adequacy of current transmission system strength nodes and minimum fault level requirements.
		Opportunity to address distribution DPV hosting capacity issues (for example, reducing fault current and reactive margins) and system strength issues through distribution network solutions.	Feasible DNSP actions that can contribute to transmission level needs.
Voltage control	Coordinated voltage control at transmission-distribution interface for times of high DER.	Reducing loading, eventually minimal loading on the transmission system and consistent voltage planning criteria for the T-D interface.	Effective reactive power exchange and voltage criteria at the T-D interface and contingencies that need to be considered.

System criteria		High DPV implications	Investigations required
	Reactive support and voltage control arrangements for highly variable, long distance VRE power flows to load centres, and more variable daily demand profiles across transmission and distribution networks.	Adequacy of voltage control strategies to manage variability at the T-D interface. due to plausible changes in DPV output over different time scales (minutes to hours).	Plausible DPV variability on load, power transfer and the intra-day voltage profile at the T-D interface against operating limits for voltage control including transformer tap changing, reactive plant switching and other voltage regulating plant[E].
		Voltage stability and other potential transfer limits restricting flow from metropolitan DPV generation centres to electrification and industrial load centres.	Power flows and limits under different electrification scenarios. Examples include: DPV soaked up by EV, data centre, and storage in the distribution network versus industrial electrification in remote locations.
	Sufficient reactive power absorption capability to securely supply load.	Changing power factor of demand as loads shift from traditionally inductive to capacitive and synch and induction motors are displaced by power electronics.	Models and approaches to represent load dynamics during high DPV scenarios.
System restoration	Ability to manage uncontrolled DPV generation during the restart process.	Impact of DPV and load behaviour on restart pathways, as discussed in Section 8.2.	Behaviour of DPV on restart pathways, in the weak and highly sensitive grid conditions expected during restart scenarios. Feasible solutions and strategies to manage operationally.

A. This has been identified as an issue in AS/NZS4777.2:2020, and other comparable DER inverter standards such IEEE1547:2018 in the United States. Demonstrated in laboratory bench testing, EMT simulation and system events internationally.

B. Including, for example, DNSP dynamic operating envelopes and other DER management functions, Volt/VAr controls and anti-islanding measures. Discussed further in Energy Catalyst, Australian Research for Power Systems Transformation research program, Topic 7 Power System Architecture – Stage 4 Report 3 Systemic Issues & Transformation Risks, at https://www.csiro.au/en/research/technology-space/energy/Electricity-transition/AR-PST/Stage-4, pp. 88-89.

C. The same potential oscillations and adverse control interactions relevant for utility scale IBR are relevant for DER inverters, with the key distinction being location in the distribution and proximity to load, device-level configuration and controls. Discussed further in: Energy Systems Integration Group (ESIG) Stability Task Force, Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems – A Practical Guide, at https://www.esig.energy/oscillations-guide/, pp 83-84.

D. Laboratory tests have shown that DPV inverters can struggle or fail to operate correctly in low system strength (low SCR) conditions. See for example University of NSW Real-Time Simulations Laboratory & University of Wollongong Australian Power Quality Research Centre, Australian Research for Power Systems Transformation research program, Topic 9 DER and Stability – Stage 4 Final Report, at https://www.csiro.au/en/research/technology-space/energy/Electricity-transition/AR-PST/Stage-4, p.6 and Section 4.

E. For example, transformer tap changers or switched shunts have maximum operation per hour/day limits that could be exceeded.

9.2 Enabling a two-sided system

Key messages

- The growth in flexible generation, storage and demand connected to the distribution system presents opportunities for the system to be planned and operated in a more two-sided manner, enabling consumers (potentially via aggregators) to gain value from providing system services and contributing to enhanced operational flexibility for managing system security.
- There are risks associated with the various forms of DER management scaling in an uncoordinated manner across different actors, with insufficient visibility, predictability, controllability and performance – potentially leading to substantial system integration costs, limited whole-of-system benefits, reduced system operability and material system security risks.
- An intentional design focus is underway to develop the system architecture, operational coordination and data exchanges that will better integrate the demand side within the distribution network, power system and market to benefit all consumers. This includes defining control hierarchy, enabling an active distribution system, improving transmission-distribution coordination, and clarifying customer agent roles.

Key actions

- AEMO continues to engage across National CER Roadmap workstreams as they progress on the roles and responsibilities, data exchange and governance required to enable a more two-sided system.
- DNSPs continue to develop DSO capabilities and work with retailers, customer agents and service providers towards standardising how these parties interact with DNSPs to gain network access and provide flexibility.
- AEMO continues to work closely with governments on better aligning measures to incentivise DER and load with system outcomes, including pricing and incentives, and demand flexibility programs visible to network and system operation, and available to participate in the market.
- Collaboration across industry, governments, connecting parties, NSPs and AEMO continues is progressing how the flexibility of large loads can be harnessed, and managed under abnormal system conditions.

9.2.1 Context

There are significant challenges and opportunities for how system security is planned and managed, associated with how the demand side step change projected over the next 10 years is integrated within the distribution system, the power system and market, including:

- managing any risks associated with the impact or contribution of demand side resources on the technical envelope,
- provision of system services from demand side technologies and the distribution system, and measures that can improve the resilience of the power system under abnormal scenarios, and
- using available flexibility on the demand side to manage, sometimes expand, the secure technical envelope, to accommodate higher renewable contributions, both utility-scale and DER.

This section draws on insights from the grid architecture discipline to highlight the key structural considerations for a secure, reliable and operable two-sided system. Grid architecture applies concepts from system engineering, network theory, and control theory, and the mathematics of ultra large-scale systems, to the electric grid and its associated structures and systems[91].

Control hierarchy for different forms of DER management

As technology evolves and new products and services emerge, it is becoming increasingly feasible for DER to be managed in different ways. Policy development, pricing and incentives are actively encouraging different forms of DER management. Coupled with the projected uptake of DER, there is potential for large volumes of coordinated DER over the next 10 years.

DER devices and management systems can respond to a range of signals, including:

- customer and site-level actions, either manual or automated, in response to dynamic price signals or based on the availability of local generation or storage,

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[91] AEMO has participated in a multi-year program on grid architecture and how it applies in Australian energy systems, from 2021 to 2025. For more information, see CSIRO, Australian Research in Power Systems Transition (AR-PST) reports for Stages 1 to 4 for Topic 7 Power System Architecture, at https://www.csiro.au/en/research/technology-space/energy/electricity-transition/ar-pst.

- voluntary signals from retailers to reduce or increase load,
- a dynamic export limit, and
- curtailment signals or activation of network support from the DNSPs.

These can be expressed in terms of hierarchical systems, control interactions and data exchanges, shown in **Figure 17**[92].

Figure 17 Five level architecture for DER management

As DER management scales, there can be material system security risks if these different signals and control levels are not planned for and managed appropriately. This can lead to coordination conflicts and other architectural issues, including adverse outcomes in the distribution network. For example, if the DNSP is unaware of third-party coordination signals impacting device behaviour and conflicting signals are sent to DER devices from multiple control entities[93].

Layered structures allow for the overall system architecture and optimisation problem to be broken into a series of smaller sub-problems at different layers, with coordination at each layer solving local sub-problems aligned with higher-level system objectives[94]. This extends to a control hierarchy with layers operating independently, focused on activities within the layer with minimal but targeted signalling between layers, allowing different forms of participation to be:

- accounted for in network and power system operations – able to be modelled, with sufficient visibility and predictability of their contribution and performance, and
- controlled and managed if required under normal and abnormal system conditions for network and system security in a scalable way, optimised at each layer with available flexibility efficiently utilised.

Distribution system

Distribution utilities around the world are evolving towards more active management of both their assets and flexible demand and DER within their networks. With increasing decentralisation, this evolution is critical for safe and reliable

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[92] Five-level hierarchical architecture outlined in IEC 61850-7-420 *Communication networks and systems for power utility automation - Part 7-420: Basic communication structure - Distributed energy resources and distribution automation logical nodes*. Edition 2, October 2021, at https://webstore.iec.ch/en/publication/34384 Discussed in more detail with examples in M. McGranaghan, D. Houseman, L. Schmitt, F. Cleveland and E. Lambert, *Enabling the Integrated Grid: Leveraging Data to Integrate Distributed Resources and Customers*, in IEEE Power and Energy Magazine, vol. 14, no. 1, pp. 83-93, Jan.-Feb. 2016, at https://ieeexplore.ieee.org/document/7366680.

[93] Discussed further in Strategen, Global Power Systems Transformation Topic 7: Power Systems Architecture, Stage 2 report, July 2023, at https://www.csiro.au/-/media/EF/Files/GPST-Roadmap/Final-Reports/Topic-7-GPST-Stage-2.pdf, page 193.

[94] Described further in GridWise Architecture Council, *A Practical Introduction to Common Grid Architecture Techniques*, April 2024, at https://gridwiseac.org/sites/default/files/2025-03/PNNL-35073_2024_GridArchitecture_White-Paper-PAL-final.pdf, Section 4.3.

operation of the distribution system, and harnessing of demand side flexibility within the layered system architecture. These are commonly referred to as DSO capabilities, listed in **Figure 18**[95].

Figure 18 Summary of distribution system operator (DSO) roles

Active system management	Enabling CER flexibility	Transmission–distribution coordination	Integrated distribution planning
Actively managing network assets, DER and flexible loads to within hosting capacity of the networks for safe, reliable and efficient operation of the distribution system in a two-way power flow environment	Mechanisms, and interfaces to value, incentivise, procure, and coordinate energy and flexibility services from DER, interacting with customer agents and service providers managing DER devices on customer's behalf.	Interaction and data exchange between the transmission and distribution system operating zones to provided observability of DER and grid state required for secure and reliable network and system operations.	Distribution system planning in consultation with the system operator and relevant transmission network, within broader integrated whole of system planning process.

Transmission-distribution interface

In the NEM, AEMO and TNSPs manage the operation of the transmission system, while distribution system operation primarily sits with the DNSPs. A high level of coordination will be required between transmission and distribution operating zones[96] for secure and reliable system operation with high levels of DER, including to:

- provide AEMO and TNSPs sufficient observability[97] of DER and DSO activities within the distribution operating zone for transmission system operations, and
- manage available DER and demand side flexibility on rare occasions where required for system level reasons, including for system security, in the transmission operating zone, through the DSO and its interactions with customer agents.

Customer interface

Customer agents bridge consumer preferences and their devices to network, system and market operations. Examples include device and management system OEMs, DER aggregators, retailers and other service providers. Customer agents can also rely on third party communication managers to transmit device data and instructions between devices. These roles, and reliance on their systems, will be increasingly relied on for coordinating DER under normal, abnormal and emergency conditions and will require appropriate access controls, cyber security, performance and system security obligations.

9.2.2 Latest status

Forms of DER participation and control hierarchy

Most DER in the NEM today is passive, responding to customer decisions and local conditions. While this is anticipated to continue being a large share of DER and load connections, more active forms of participation are emerging in the NEM, influenced by tariffs and other incentives. This includes site level optimisation of storage with local load and DPV, DNSP dynamic export limits for DPV sites, community batteries, and aggregation.

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[95] While interpretations of DSO roles and associated capabilities vary across jurisdictions, they can be generally summarised as per the figure. Adapted from Energy Catalyst, Australian Research for Power Systems Transformation research program, *Topic 7 Power System Architecture – Stage 4 Report 4 Distribution System Operator (DSO) Models*, at https://www.csiro.au/en/research/technology-space/energy/Electricity-transition/AR-PST/Stage-4, Section 6.5.

[96] Operating zone refers to the grid area that the system operator is responsible for operating, sometimes referred to as "responsibility area".

[97] Observability in this context refers to the depth of awareness of surrounding grids the system operator needs to manage its operating zone effectively.

There is currently no formalised, uniformly applied control hierarchy in the NEM for the different control signals and instructions sent to DER devices and management systems to ensure network and system security limits and responses take precedence over market and other discretionary actions.

Distribution system and Transmission-Distribution (T-D) interface

NEM DNSPs are trialling and developing DSO capabilities through their DER Integration strategies[98]. DNSPs also play a role today enabling demand side flexibility, making their controlled load capability available and are leasing network battery capacity to retailers.

As discussed in Section 9.1, AEMO is actively working with DNSPs and the Energy Networks Association (ENA) on the functional requirements for operating a high-DER power system. Longer term, with the step change in the demand side anticipated over the next 5-10 years, T-D coordination needs will become more complex and will require well-developed DSO roles and capability, and a mature T-D interface.

Customer interface

Many customer agent roles – actors who control or interact with DER – are not yet formally recognised in energy frameworks, resulting in gaps in performance, governance and customer protections. DER inverter OEMs are becoming increasingly important actors in the system given the level of DPV uptake in the NEM, and interact remotely with their fleets in various ways, including device firmware and settings updates and communicating DNSP flexible export limits and emergency curtailment signals to devices, as well as third-party market signals.

Price-responsive DER and demand side flexibility enabled by retailers and other customer agents managing their devices is not operationally visible to NSPs or AEMO, and cannot be used to manage these fleets, even under emergency conditions.

9.2.3 AEMO's forward plan

Collaboration with DNSPs

AEMO is continuing to work collaboratively with DNSPs and the ENA towards development of a layered system architecture in which DNSPs manage DER and flexibility in their operating zone and coordinate with transmission system operations to manage the aggregate impact on system security, and to harness this flexibility at system-level.

The T-D coordination and DER management for system security functions are extensions of underlying DSO capabilities, which DNSPs are implementing today, and the CER Taskforce is formalising through the National CER Roadmap *Roles Defined* and *Data Sharing* workstreams. AEMO will continue to work with DNSPs as they develop these capabilities – including the interface between retailers, customer agents and service providers – towards standardisation in key use cases for how these parties interact with DNSPs to gain access to data and provide flexibility. These will be considered in the next phase of AEMO's CER Data Exchange detailed design and implementation[99].

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[98] Submitted to the AER as part of DNSP regulatory proposals in accordance with the AER's *DER integration expenditure guidance note*. Strategies are at the relevant DNSP determination pages on the AER website, at https://www.aer.gov.au/industry/registers/decisions.

[99] AEMO, Consumer Energy Resources (CER) Data Exchange, at https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/consumer-energy-resources-data-exchange.

Effective T-D coordination and DNSP responsibilities for managing system security, and the associated data exchange and coordination capabilities, are critical for effectively managing system security in a high DER future.

Policy development

AEMO will continue to engage with governments, market bodies and industry through the National CER Roadmap workstreams. The consultation papers published by roadmap workstreams in 2025 highlighted several areas of focus relevant to enabling the system architecture for a two-sided system, summarised in **Table 18**.

Table 18 National CER Roadmap workstreams and relevance to enabling a two-sided system

Workstream	Relevant focus areas
Redefining roles [M3, P5][A]	• DSO roles and the coordination required between transmission and distribution system operation, including for system security and enabling demand side flexibility at the system level. • Customer agents involved in the management of DER devices, and appropriate control hierarchy for responses required under normal, abnormal and extreme abnormal system conditions.
Data sharing [M2]	• Data sharing and coordination required across actors, aspects requiring consistency through standardisation and defining of priority use cases, as well as roles and expectations for data collection, validation and exchange.
Regulatory framework [T1][B]	• Minimum device level requirements for interoperability, assessing requirements for different actors and use cases, applicable standards and priority gaps that need to be addressed.
Technical standards [T2][C]	• National technical regulatory framework for CER, considering requirements for system operation, security and reliability technical standards, compliance and enforcement.

A. Summarised at CER Taskforce, Redefining roles and responsibilities for power system and market operations in a high CER future – Consultation Paper to progress M3/P5 workstreams of the National CER Roadmap, 9 July 2025, at https://consult.dcceew.gov.au/national-cer-roadmap-redefine-roles-m3-p5, Section 3.2.1.
B. CER Taskforce, Technical Standards for Consumer Energy Resources (CER) Interoperability - Consultation Paper, 15 August 2025, at https://consult.dcceew.gov.au/natl-cer-roadmap-tech-priorities-consult.
C. CER Taskforce, National Technical Regulatory Framework - Draft prototype, 15 August 2025, at https://consult.dcceew.gov.au/natl-cer-roadmap-tech-priorities-consult.

National CER Roadmap recommendations to Ministers are expected in December 2025 and will outline how these areas will be progressed in 2026. The effective design and implementation of these reforms is critical for safely and securely integrating DER and enabling demand side flexibility.

AEMO will continue to work with state and federal governments to promote measures and policy actions that help align DER and responsive demand with whole of system outcomes. Opportunities include:

- pricing and incentives for solar soaking and peak reduction (such as the Cheaper Home Batteries program and the proposed Solar Sharer Offer scheme) and addressing counter-acting incentives where they exist,
- a broader view of demand side flexibility that recognises its value in a high-renewable power system, throughout the day and year, not just for peak demand and MSL scenarios, and
- demand flexibility programs visible to network and system operations, and, where feasible, available to participate in the wholesale market.

Voluntarily Scheduled Resource implementation

AEMO is currently engaging with industry on the implementation of the AEMC's *Integrating price responsive resources into the NEM* (IPRR) rule. The framework allows DER aggregators to participate in energy and FCAS markets, under the new voluntarily scheduled resource providers (VSRP) participant category. AEMO has recently published its *VSR Guidelines* outlining requirements for participation[100].

As part of implementing the IPPR rule, AEMO is developing an incentive mechanism to encourage participation prior to the commencement in 2027. AEMO is also collaborating with DNSPs and industry on DNSP data requirements for safely and securely hosting VSRP DER aggregations within the distribution system.

The NEM Review draft report proposes that a wider range of price-responsive resources should become visible or dispatchable so they can contribute to market price formation. The responsibility to make this activity visible to system and market operations would be placed on the relevant participant[101].

Together, the above reforms help to mitigate the potential risks of increasing levels of flexible, price-responsive resources and to leverage the opportunities of a two-sided system to enhance system security management in a low- or zero-emissions power system.

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[100] AEMO, *Voluntary Scheduled Resource Guidelines* and *Final Report*, 27 November 2025, at https://www.aemo.com.au/consultations/current-and-closed-consultations/voluntarily-scheduled-resources-guidelines-consultation.

[101] NEM Review Panel, *National Electricity Market wholesale market settings review* – draft report, 6 August 2025, at https://www.dcceew.gov.au/energy/markets/nem-wms-review, Recommendation 2B.

10 Technology developments

The changing capabilities of technologies, and the changing prevalence of different technologies in the NEM, create challenges and opportunities for system security. AEMO is working to mitigate potential negative impacts and support improved understanding and confidence in new opportunities.

This section discusses three technologies that are at the forefront of how security is evolving in the NEM. These are:

- grid-forming (GFM) inverters,
- synchronous generators with clutches that can act as synchronous condensers, and
- large inverter-based loads, particularly data centres.

Additionally, Section 10.4 presents an assessment of emerging technologies that may contribute to security in the future.

10.1 Grid-forming inverters

Key messages

- GFM inverter capabilities can be designed and tuned in a wide variety of ways by manufacturers as well as asset operators. This is their great strength, allowing them to contribute to system security in many ways, while their biggest challenge is that stakeholders, particularly NSPs and AEMO, need confidence in specific reliable behaviour under all system conditions.
- Significant progress is being made to enable GFM inverters to deliver many security services in the NEM. Recent highlights include progress on specification of synthetic inertia and early deployment of a GW-scale pipeline of GFM to support stable voltage waveforms.
- The provision of protection quality fault current remains a key limitation of GFM. Reviews and AEMO studies highlight that GFM fault contribution is inherently different from synchronous machines, creating doubts for reliable protection system operation.

Key actions

- The GFM Access Standards Technical Requirements Review process, led by AEMO, is considering a dedicated GFM category to shift compliance away from grid-following (GFL) inverter-specific standards that can degrade GFM performance.
- AEMO is conducting analysis, as part of the Engineering Roadmap, to enhance understanding of fault current performance from GFM inverters and to quantify system strength support from GFM inverters.
- AEMO has initiated procurement of Type 2 Transitional Services to trial GFM inverter provision of protection quality fault current and contributions to black start.
- TNSP investments to meet minimum fault levels are urgently required – these cannot be delayed while GFM capability develops further.

10.1.1 Context

GFM inverters are a class of power electronics defined by advanced capabilities to control their output voltage waveform. It is this control logic that distinguishes GFM from the earlier class of inverters, referred to as GFL inverters, which 'follow' the grid voltage and focus on controlling current output. Almost all IBR connected to the NEM today are GFL, but there are gigawatts of GFM projects in the planning pipeline. **Figure 19** presents the key differences between GFL and GFM.

Figure 19 Contrasting characteristics of grid-following and grid-forming inverters

Grid-following inverters (GFL) Control system **synchronises** to the grid voltage waveform	**Grid-forming inverters (GFM)** Control system **sets its own** internal voltage waveform
Require a voltage signal from the grid. Shuts down if it loses this.	No reliance on grid voltage. Can operate with or without grid connection.
Limited possibilities for grid support. Can adjust power, but limited by speed & risk of interactions with other GFL.	Extensive possibilities for grid support. Very fast, intrinsic control of voltage waveform.
Most inverters in the NEM today are grid-following.	There are GW of GFM BESS planned for the NEM. These will provide inertia & system strength, with other services in development.

Definition of GFM used in AEMO's Voluntary Specifications for Grid-forming Inverters[102]: "A grid-forming inverter maintains a constant internal voltage phasor in a short time frame, with magnitude and frequency set locally by the inverter, thereby allowing immediate response to a change in the external grid. On a longer timescale, the internal voltage phasor may vary to achieve desired performance".

The ability of GFM inverters to control voltage with speed and precision allows them to be tuned to interact with the grid in a variety of ways, including to provide many benefits to system security. AEMO's *Voluntary Specifications for Grid-forming Inverters* specifies six core capabilities of GFM inverters, as well as four additional capabilities that GFM inverters may provide (see **Figure 20** below). Typically, multiple GFM capabilities are required to deliver system security services, such as system strength.

These characteristics enable GFM inverter manufacturers to build their own distinct control systems – the details of which are commercial in confidence – and GFM plant owners to tune the behaviour of their assets in a wide variety of ways to suit specific project and network objectives.

This versatility of GFM behaviour is central to both the opportunities for this technology and the challenges of building stakeholder confidence in reliable, predictable behaviour.

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[102] AEMO, *Voluntary Specification for Grid-forming Inverters*, at https://www.aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf.

Figure 20 Core and additional capabilities of grid-forming inverters

Core GFM capabilities

- Voltage source behaviour
- Frequency domain response
- Inertial response
- Surviving the loss of last synchronous connection
- Weak grid operation and system strength support
- Oscillation damping capability

Additional GFM capabilities

- Headroom and energy buffer
- Current capacity above continuous rating
- Black start capability

GFM deployment in the NEM

The NEM has been an early adopter market for GFM project deployment. As of November 2025, there are 10 operational GFM assets in the NEM, 94 GFM assets in the connections pipeline in the NEM (including 2 GW of GFM BESS registered and being commissioned, and 1 GW constructed and awaiting registration[103]), and two assets in the pipeline in the WEM (see **Figure 21**). The operational GFM inverters are all connected to BESS. Some projects with GFM functionality are currently contracted to provide security services, such as system strength[104] and voltage stability[105].

Current TNSP proposals, such as Powerlink[106] and Transgrid[107] RIT-T's for system strength, include contracting with several gigawatts of GFM BESS by 2034. These proposed contracts are all for the procurement of efficient levels of system strength, providing a stable voltage waveforms to support GFL IBR.

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[103] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard.

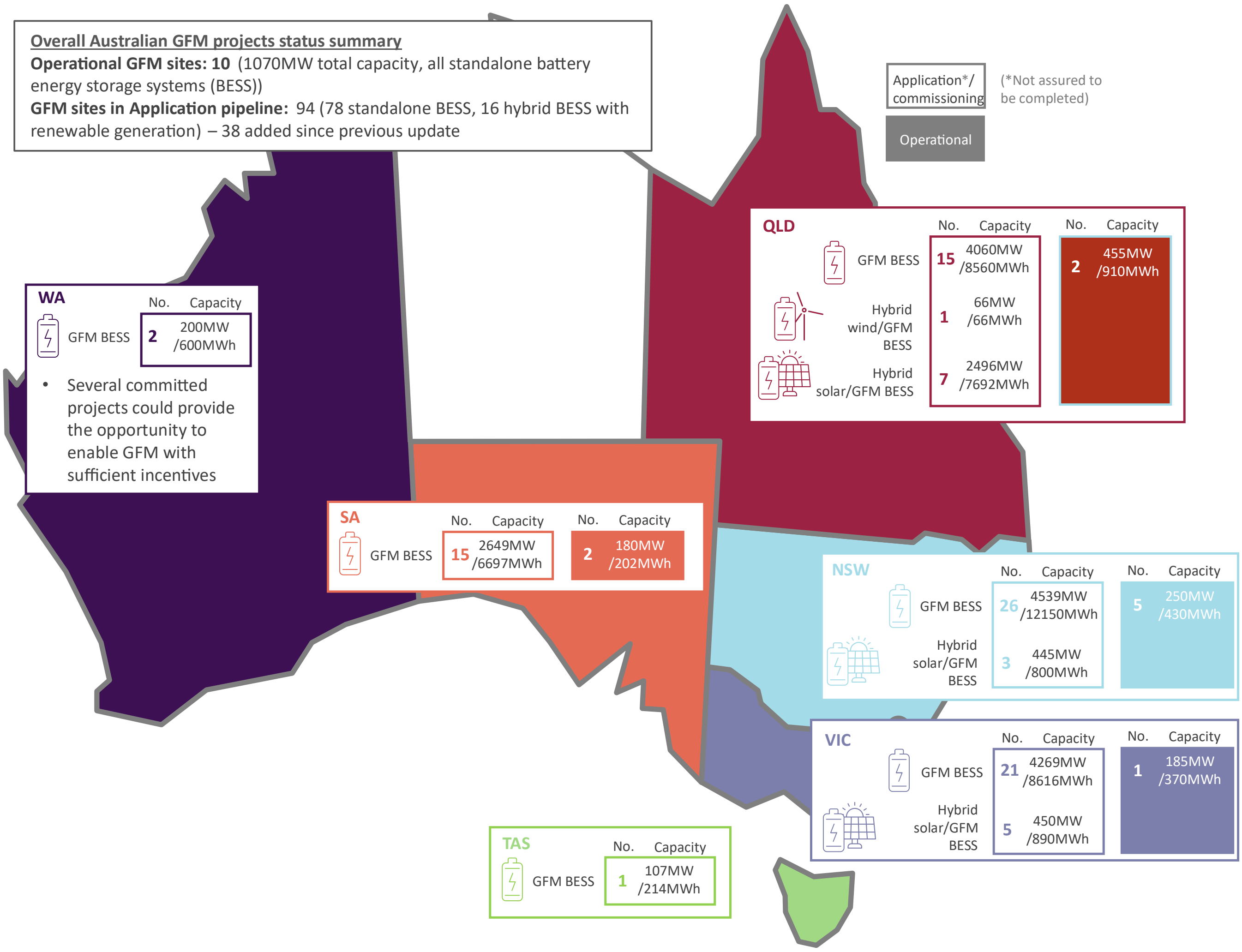
[104] At https://www.aemo.com.au/newsroom/media-release/aemo-awards-contract-to-improve-system-security-in-murray-river-rez.

[105] At https://www.transgrid.com.au/media-publications/news-articles/big-battery-to-deliver-additional-renewable-energy-to-riverina-customers.

[106] At https://www.powerlink.com.au/sites/default/files/2025-07/Addressing%20System%20Strength%20Requirements%20from%20Dec%202025%20-%20PACR%20-%20June%202025.pdf.

[107] At https://www.transgrid.com.au/media/kfhd21bq/250812-transgrid-system-strength-pacr.pdf.

Figure 21 GFM projects in the NEM and WEM



Overall Australian GFM projects status summary
Operational GFM sites: 10 (1070MW total capacity, all standalone battery energy storage systems (BESS))
GFM sites in Application pipeline: 94 (78 standalone BESS, 16 hybrid BESS with renewable generation) – 38 added since previous update

WA

	No.	Capacity
GFM BESS	2	200MW /600MWh

- Several committed projects could provide the opportunity to enable GFM with sufficient incentives

QLD

	No.	Capacity	No.	Capacity
GFM BESS	15	4060MW /8560MWh	2	455MW /910MWh
Hybrid wind/GFM BESS	1	66MW /66MWh		
Hybrid solar/GFM BESS	7	2496MW /7692MWh		

SA

	No.	Capacity	No.	Capacity
GFM BESS	15	2649MW /6697MWh	2	180MW /202MWh

NSW

	No.	Capacity	No.	Capacity
GFM BESS	26	4539MW /12150MWh	5	250MW /430MWh
Hybrid solar/GFM BESS	3	445MW /800MWh		

VIC

	No.	Capacity	No.	Capacity
GFM BESS	21	4269MW /8616MWh	1	185MW /370MWh
Hybrid solar/GFM BESS	5	450MW /890MWh		

TAS

	No.	Capacity
GFM BESS	1	107MW /214MWh

Note: AEMO connections pipeline, as of July 2025.

AEMO's work on integrating GFM technology

AEMO is currently working toward refining the connections requirements and process for GFM projects and contributing to technical analysis and trials – including Type 2 Transitional Service trials – that build confidence in GFM performance. These are collaborative engagements with market participants, GFM inverter OEMs, and TNSPs – who hold responsibility for contracting system strength and inertia services (as System Strength Service Providers and Inertia Service Providers). **Table 19** summarises AEMO's publications related to GFM.

Table 19 AEMO publications related to GFM

Publication	Date	Achievements/objectives
Application of Advanced Grid-scale Inverters in the NEM[A]	Aug 2021	Identified the need for GFM inverter demonstration at scale.
Voluntary Specification for Grid-Forming Inverters[B]	May 2023	GFM inverter capabilities defined for power system security.
Testing Framework for Grid-Forming Inverters[C]	Jan 2024	Simulation test methods developed to determine whether GFM inverters will provide expected power system security benefits.

Publication	Date	Achievements/objectives
The Role and Need for Inertia in a NEM-Like System[D]	May 2024	Developed understanding of synthetic versus synchronous inertia in the NEM to guide regulatory change.
Quantifying Synthetic Inertia of a GFM BESS – Technical Note[E]	Sep 2024	Explored constraints of GFM inverter capability in providing synthetic inertia.
GFM Access Standards Technical Requirements Review[F]	Aug 2025	Review of NER technical requirements to facilitate the delivery of GFM inverter services and capabilities.
Type 2 Transitional Service Statements of Need	Oct 2025	Proposing trials of GFM protection-quality fault current[G], black start from GFM[H], and Zero Synchronous Generation[I].
GFM Protection Quality Fault Current – Independent Consultant Reports[108]	Nov 2025	Consultant reports providing detailed technical content on interaction between GFM and existing protection systems
Engineering Roadmap new technologies workstream[J]	Expected 2025-26	Analyse fault current performance from GFM. Quantify system strength support from GFM.

A. At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf.
B. At https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf.
C. At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan-2024.pdf.
D. At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/ao_geas-role-of-inertia-in-a-nem-like-system.pdf.
E. At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/quantifying-synthetic-inertia-from-gfm-bess.pdf.
F. At https://www.aemo.com.au/consultations/current-and-closed-consultations/grid-forming-technology-access-standards-technical-requirements-review.
G. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/grid-forming-inverter-protection-quality-fault-current-trial.
H. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/black-start-capability-from-ibr.
I. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/zero-synchronous-generation-trial.
J. At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/engineering-roadmap-fy2026-priority-actions-report.pdf.

10.1.2 Latest status

Connections standards

The connections process has at times proven challenging for GFM projects, as observed by Australian Renewable Energy Agency (ARENA)-supported GFM projects[109], requiring trade-offs between performance against the connection standard or against system security service specifications. The GFM Access Standards Technical Requirements Review[110] is addressing this by considering a potential GFM category to reduce the unnecessary GFM emulation of synchronous generators that can degrade GFM performance.

Voluntary specification

AEMO was one of the first international system operators (ISOs) to publish a *Voluntary Specification for Grid-forming Inverters*[111]. This voluntary specification has been referenced by multiple ISOs while determining GFM specifications for their networks, and some have adopted key features of the AEMO specification. Collaboration through ISON continues to facilitate knowledge sharing of international experience with GFM.

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[108] See https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap/engineering-roadmap-execution-reports, noting the disclaimer that the views expressed in the reports are those of the consultants, not AEMO.

[109] At https://arena.gov.au/assets/2025/08/GFM_Webinar_Slides_full.pdf.

[110] At https://www.aemo.com.au/consultations/current-and-closed-consultations/grid-forming-technology-access-standards-technical-requirements-review.

[111] AEMO, January 2024, *Voluntary Specification for Grid-forming Inverters: Core Requirements Test Framework*, at https://aemo.com.au/~/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan%202024.pdf.

In 2025, AEMO conducted studies to compare the performance of some existing and prospective GFM BESS projects in the NEM against the characteristics outlined in the Voluntary Specification. The findings help demonstrate the ability of the GFM BESS to meet core requirements and specifically assess these requirements across projects of various sizes, different OEMs, and distinct Point of Connection (PoC) characteristics. This is crucial for building confidence in the current capabilities of GFM BESS as the NEM transitions towards operating with high renewable contributions and reflects AEMO's commitment to monitoring the specification's practical impact and supporting its ongoing refinement.

The results, summarised in **Figure 22**, indicate that two GFM BESS projects successfully met all the requirements of the core capabilities listed in the Voluntary Specification, thereby providing the expected benefits from GFM technology. This corroborates the practical applicability of the thresholds specified for GFM core capabilities. The results indicate a trend of improved compliance with the criteria over time. This suggests increasing industry familiarity with the specification.

It is important to note that model parameter tuning was not conducted, and potential performance improvements were not considered in these studies. AEMO acknowledges that the tested models might not have been specifically tuned to meet the core GFM capabilities outlined in the Voluntary Specification, so the performance of the tested projects could have improved with more targeted tuning.

The voluntary specification and associated simulation tests are intended to guide industry development and do not replace or override existing NER performance requirements. Projects that did not meet all voluntary thresholds remain subject to the full suite of NER technical standards, which continue to underpin system security. These findings highlight areas for improvement and inform ongoing collaboration with OEMs to enhance grid-forming capability over time.

Figure 22 Preliminary results of testing five GFM projects against the voluntary specification

				Oldest		→		Newest
GFM core capability			Test	Project 1	Project 2	Project 3	Project 4	Project 5
Weak grid operation & system strength support. Inertia	Voltage source. Oscillation damping	Loss of last synchronous machine	Trial A	Fail	Fail	Pass	Pass	Pass
			Trial B	Fail	Fail	Pass	Pass	Pass
			Trial C	Fail	Fail	Pass	Pass	Pass
			Trial D	Fail	Fail	Pass	Pass	Pass
			SCR step	Fail	Fail	Pass	Pass	Fail
			Angle step	Fail	Fail	Marginal Pass	Pass	Marginal Pass
			RoCoF	Pass	Pass	Pass	Pass	Pass

Survey of TNSP protection equipment

Compounding the variability in GFM behaviour, there is significant variability in the types of protection equipment and design of protection schemes used across the NEM. In 2025, AEMO surveyed NEM TNSPs – who are responsible for the safe operation of protection systems – to collate information on the equipment and schemes in use and any observed operational issues during periods of high IBR contributions. **Table 20** presents some insights from this survey.

Table 20 Insights from TNSP protection survey

Protection topic	Comments or observed issues with IBR
Protective relays	Variety of relay vendors and relay technology mix (electromechanical, microprocessor, numerical) used amongst respondents. TNSPs are phasing out electromechanical and moving towards modern numerical/digital relays, which now make up anywhere between 70-95% of respondent relays.
Fault sequence components	Negative sequence current commonly used in fault detection. However, negative-sequence fault current is not consistently or adequately provided by IBR. In high-IBR contexts, zero sequence current is being used by some TNSPs in relays where possible. Relay maloperations have been observed due to inconsistent negative-sequence fault currents and TNSPs are actively monitoring the situation as IBR concentration increases.
Distance and directional relays	Commonly used, but susceptible to maloperation with increasing IBR concentration. Are typically reliant on negative-sequence fault current which is not consistently or adequately demonstrated by IBR.
Current differential relays	Commonly deployed near IBR and throughout transmission network. Less susceptible to variable fault current components of IBR than distance/directional. Differential relaying is reliant on high-speed communication.
Compatibility of today's protection with tomorrow's grid	TNSPs noted that the varying/inconsistent behaviour of IBR makes planning, modelling, and analysis difficult. Protection requirements, settings, and technology will likely need to evolve with the shift to increasing concentrations of IBR.
Additional studies or resources to improve relay performance with high-IBR	TNSPs showed interest in access to appropriate dynamic relay modelling software, improved modelling techniques, and clear definition of scope for dynamic protection assessment to address new risks. Additional interest was shown for generator compliance changes to minimise IBR risks, such as minimum fault and current sequence component injection requirements.

Type 2 Transitional Services Trials

In October 2025, AEMO published Statements of Need for Type 2 Transitional Services from GFM (see Section 2.3.2). These are to evaluate black start from GFM and operation of a large isolated sub-network without synchronous generation, and to assess whether GFM inverters can provide fault current of sufficient magnitude, duration, and composition (for example, relevant positive and negative sequence components and waveform properties) for protection relays to operate correctly under diverse system operation and fault conditions.

Status of GFM provision of security services

GFM developments are continuing at pace. The last year has seen substantial progress regarding the specification and initiation of procurement of stable voltage waveform support and synthetic inertia. The latest progress towards GFM providing security services in the NEM at scale is captured in **Figure 23** and **Table 21**.

Figure 23 Status of GFM provision of security services in the NEM

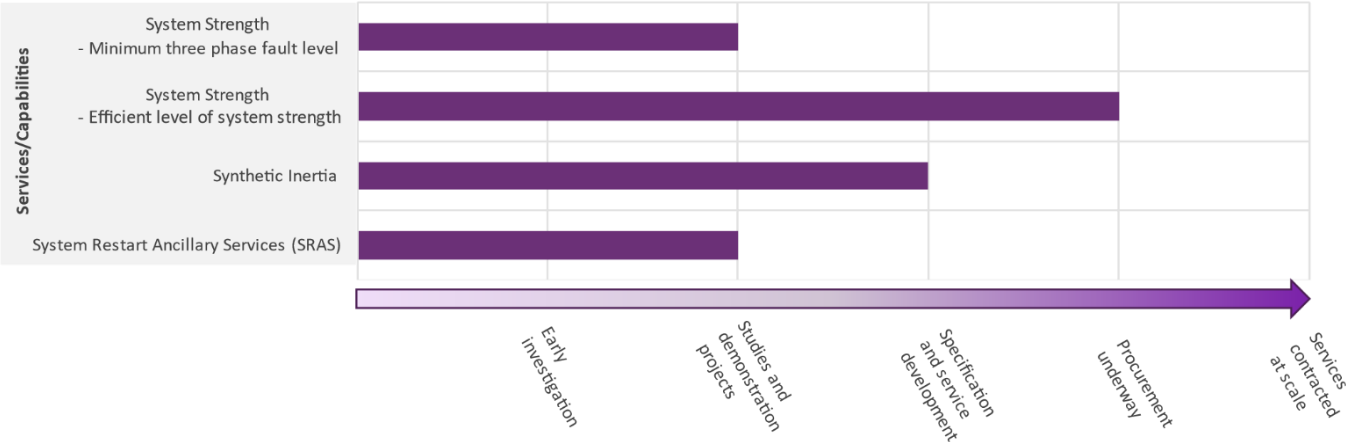


Table 21 Services relevant to GFM inverters, status of readiness and progress

Service/capability description	GFM inverters readiness to provide service	Work underway to advance readiness
System strength – the ability to maintain and control the voltage both during steady state operation and following a disturbance. The NEM system strength framework defines two specific procurement targets: minimum level (fault current) and efficient level (stable voltage waveform).		
Minimum level (fault current)	Currently in the NEM, minimum levels of system strength must be provided by protection quality fault current[A], which GFM inverters have not yet demonstrated capability to provide. Recent reviews of domestic and international experience by Aurecon[B], Amplitude[C], and ETIK[D] reported that: • GFM inverters provide lower fault contribution relative to their nameplate capacity as their semiconducting switching devices do not support large overcurrent. However, GFM may still be cost-effective. • IBR present several risks to network protection systems that require further research by TNSPs to address. One such risk is protection maloperation caused by transient oscillations and dynamic impedance variation resulting from GFM inverter droop and current-limiting behaviour during faults. • There is a need to improve modelling practices, such as using wide-area EMT simulations and accurate IBR models, to capture the dynamic behaviours of IBR and protection systems.	AEMO is actively monitoring the performance of the existing GFM projects through available high resolution monitoring systems to determine their provision of fault current during system faults. AEMO is conducting a study of GFM fault current under the FY26 Engineering Roadmap using EMT modelling with a feasibility analysis on hardware-in-loop (HIL) based assessment for GFM BESS fault response[E]. AEMO is seeking to accelerate understanding and development of GFM fault current provision through a Type 2 Transitional Services trial[F]. AEMO receives briefings from GFM OEMs and in 2025 surveyed GFM OEMs to understand the capabilities and limitations of their technology, including the ability of their systems to provide protection-quality fault current.
Efficient level (stable voltage waveform)	The current System Strength Impact Assessment Guidelines enable market participants to self-remediate their impacts using GFM to avoid system strength charges. This is driving a large pipeline of GFM BESS in connections queue[G]. AEMO's simulation analysis on GFM Voluntary Specification suggested GFM BESS with appropriate tuning can provide system strength to help stabilise nearby grid-following inverters. Complementing this, AEMO's analysis and modelling of the Dalrymple GFM BESS during the 28 December 2023 events showed that the BESS successfully formed and sustained a local island containing a nearby Wind Farm and local load, maintaining voltage and	To date, Transgrid has published a technical performance specification for the procurement of stable voltage waveform support services from GFM BESS[L]. TNSP RIT-Ts propose to contract over 8 GW of GFM BESS by 2034 to meet efficient system strength levels. For example, Transgrid's preferred option for stable voltage waveform includes 14 new synchronous condensers and 4.8 GW of new GFM BESS[M]. AEMO is conducting studies to evaluate the performance of GFM to provide system strength support for stabilising GFL IBR and comparing this performance to that of synchronous condensers.

Service/capability description	GFM inverters readiness to provide service	Work underway to advance readiness
	frequency within acceptable ranges and supporting re-synchronisation to the main grid, demonstrating grid-forming performance under real incident conditions[H]. GFM inverter technology is rapidly moving from concept to mainstream practice for delivering efficient levels of system strength. Recent planning and investment work by TNSPs[J] now routinely treats GFM BESS providing "stable voltage waveform support" as part of the optimal portfolio for accommodating high levels of IBR, with the Koorangie GFM BESS[K] already contracted to provide system strength services, and other TNSPs proposing multi-GW portfolios of GFM BESS in their system strength RIT-Ts.	
Inertia – the ability of the power system to reduce the rate at which frequency changes.		
	GFM inverters can emulate the inertial response of synchronous machines to provide power system inertia. This behaviour is referred to as a synthetic inertia response. Simulations, by AEMO and Vysus[N], and field data have demonstrated that synthetic inertia provided by GFM plants can effectively contribute to RoCoF management. Synthetic inertia responses to real system events in the NEM have been successfully demonstrated by the Hornsdale Power Reserve[P]. Field data from the Wallgrove[Q] BESS indicates that this BESS could provide FFR and inertia to at least nameplate capacity around three-quarters of the time. Functional requirements and testing specifications to quantify inertia from non-synchronous plant (synthetic inertia) are now included in AEMO's Inertia Network Services Specification[R]. TNSPs are now able to procure synthetic inertia services to meet the *inertia requirements* following the ISF rule[S].	The quantification of an inertial response from IBR plant is a relatively new but quickly evolving area, with rapid advancements in technology being made at the time of publishing. Studies by AEMO have found that quantifying the synthetic inertia from GFM plant depends on several factors, including methodological choices, and remains an area of active investigation[T]. AEMO will continue to consult with industry and update the Inertia Network Services Specification as both technology and best practice evolves. Access standards remain a challenge for GFM plant in providing inertia, as they are still assessed against security/performance metrics intended for GFL plant[U]. This will be reviewed as part of the Grid-forming Technology Access Standards Review[V].
System Restart – restart services enable the restoration of electricity supply following a complete shut-down of all, or a substantial part of, the power system. These services are procured by AEMO in the NEM as System Restart Ancillary Services.		
	There are limited examples internationally of GFM plant providing black start services, the most recent examples being a GFM BESS islanded system black-start trial in 2021[W], and the 2024 commissioning of a black-start capable GFM BESS in Hawaii[X]. GFM plant possess capabilities supportive of the system restart process, align with a NEM high-IBR future, and present a clear opportunity to ensure future restart capability[Y]. The NER allows batteries to provide SRAS, with GFM inverters providing a technical pathway for BESS to potentially meet SRAS requirements. However, during the SRAS procurement round that took place in 2023, no BESS proponents were successful due to a combination of technical and economic factors.	Type 2 Transitional Service trial of GFM black start[Z]. The Reliability Panel's new system restart standard may enable consideration of a greater range of technologies for SRAS. Further information about system restart is in Section 8.2.

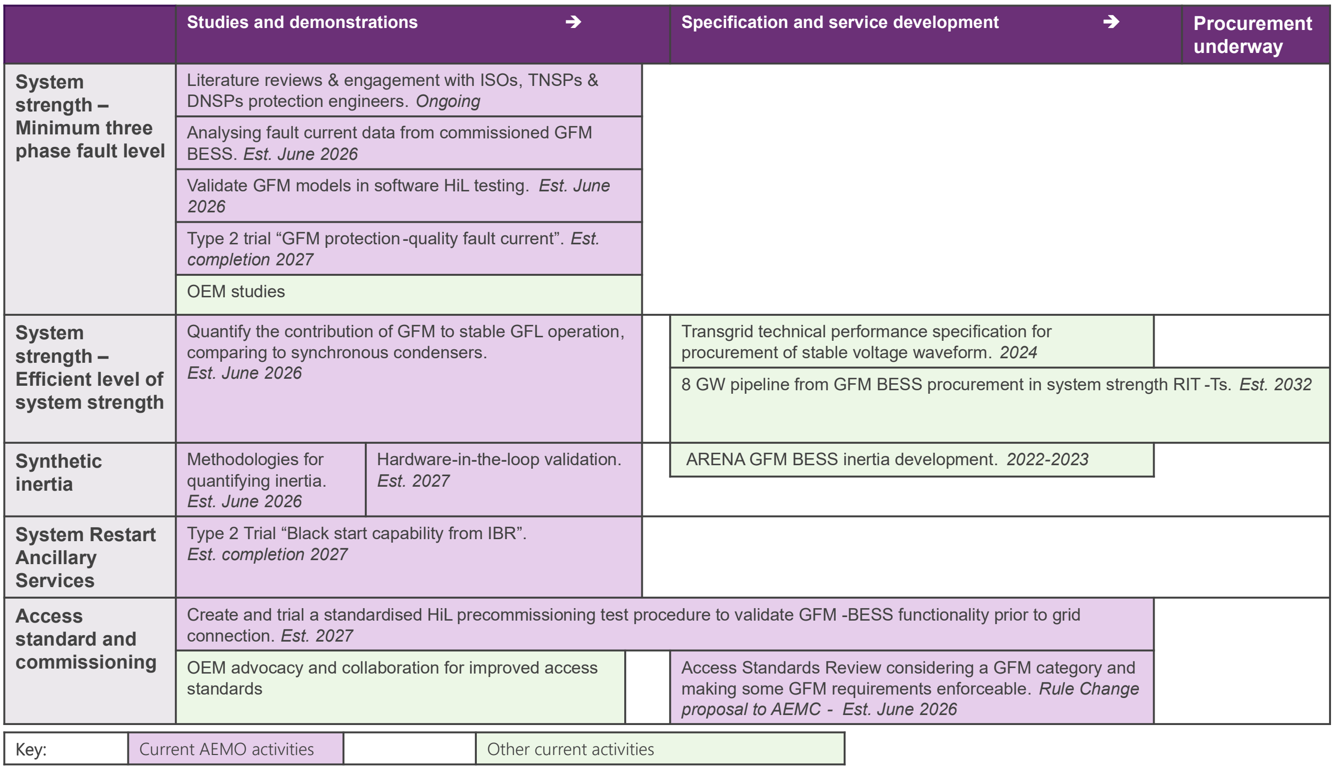
A. AEMO's May 2024 update to the 2023 ESOO noted that minimum fault level requirements "must be delivered by devices that can provide protection-quality levels of fault current – such as new synchronous condensers, service contracts with existing hydro or thermal units, or through the retrofit of those existing units themselves". See page 43 at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/may-2024-update-to-the-2023-electricity-statement-of-opportunities.pdf.

B. Aurecon (2024), *Advice on the maturity of grid forming inverter solutions for system strength*, at https://www.transgrid.com.au/media/diyb5fng/2403-aurecon_maturity-of-grid-forming-inverter-solutions-for-system-strength.pdf.
C. Amplitude (2025), *Grid Forming BESS Fault Current Contribution Study Scope*, see Grid-Forming Inverters section at https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap/engineering-roadmap-execution-reports.
D. ETIK (2025), *Grid-Forming and Grid-Following Inverter Fault Current Contribution*, see Grid-Forming Inverters section at https://www.aemo.com.au/initiatives/major-programs/engineering-roadmap/engineering-roadmap-execution-reports.
E. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/engineering-roadmap-fy2026-priority-actions-report.pdf?rev=e99db0d3c01543d584e25df0df6936ad&sc_lang=en
F. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/grid-forming-inverter-protection-quality-fault-current-trial.
G. Transgrid (2025), *Meeting system strength requirements in NSW*, at https://www.transgrid.com.au/media/kzqd14sn/2507-transgrid-pacr-meeting-system-strength-requirements-in-nsw.pdf.
H. See https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2024/analysis_and_modelling_of_dalrymple_bess_performance_december_2023_events.pdf.
J. See Powerlink's Unlocking Battery Potential report at https://www.powerlink.com.au/sites/default/files/2025-11/Unlocking%20Battery%20Potential%20-%20Battery%20attributes%20and%20locations%20to%20minimise%20total%20system%20cost.pdf
K. See VIC Koorangie BESS system strength support at https://www.aemo.com.au/-/media/files/initiatives/victorian-system-strength-requirement-rit/victorian-system-strength-requirement-rit-t-pacr.pdf.
L. Transgrid (2024), *Transgrid's technical performance and power system modelling requirements for stable voltage waveform support services from grid-forming BESS*, at https://www.transgrid.com.au/media/fctbpgif/2406-transgrid_stable-voltage-waveform-support-specifications-for-grid-forming-bess.pdf.
M. Transgrid (2024), *Project Assessment Draft Report for meeting system strength requirements in New South Wales*, page 5, at https://www.transgrid.com.au/media/fo0maqsh/2406-transgrid_meeting-system-strength-requirements-in-nsw-padr.pdf.
N. Vysus (2024), *The Role and Need For Inertia in a NEM-Like System*, at https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2024/ao_geas-role-of-inertia-in-a-nem-like-system.pdf.
P. ARENA (2023), *Hornsdale Power Reserve Expansion – Project Summary Report – Full Inertia Trial*, at https://arena.gov.au/assets/2024/02/Neoen-Hornsdale-Power-Reserve-Upgrade-Project-Summary-Report.pdf.
Q. Lumea (2024), *Final Knowledge Sharing Report – Wallgrove Grid Battery*, at https://www.lumea.com.au/media/uwnd1wx0/final-knowledge-sharing-report-submission.pdf.
R. Published as schedule A of the 2024 Inertia Requirements Methodology, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/inertia-requirements-methodology-v2-0.pdf.
S. Prior to the ISF rule, NER 5.20B.4(d) explicitly prevented the use of synthetic inertia to meet minimum inertia requirements.
T. AEMO (2024), *Quantifying Synthetic Inertia of a Grid-forming Battery Energy Storage System– Technical Note*, at https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2024/quantifying-synthetic-inertia-from-gfm-bess.pdf.
U. ARENA (2025), *Grid-Forming Battery Portfolio Series: Summary Report*, at https://arena.gov.au/assets/2025/08/GFM_Webinar_Slides_full.pdf.
V. At https://www.aemo.com.au/consultations/current-and-closed-consultations/grid-forming-technology-access-standards-technical-requirements-review.
W. At https://ieeexplore.ieee.org/document/10117471.
X. At https://www.canarymedia.com/articles/energy-storage/a-huge-battery-has-replaced-hawaiis-last-coal-plant.
Y. AEMO (2025), *System Restart Technical Advice*, at https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/system-restart-technical-advice.pdf.
Z. See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-2-services/black-start-capability-from-ibr.

10.1.3 AEMO's forward plans

AEMO is continuing to collaborate on evaluating and evolving GFM performance to build confidence amongst all stakeholders, particularly TNSPs (as System Strength Service Providers and Inertia Service Providers). **Figure 24** presents some of the actions underway – which largely focus on evolving GFM capabilities – as well as highlighting further opportunities which can contribute to evolving the system.

Figure 24 Actions and opportunities to progress GFM provision of security services



	Studies and demonstrations ➔	Specification and service development ➔	Procurement underway
System strength – Minimum three phase fault level	Literature reviews & engagement with ISOs, TNSPs & DNSPs protection engineers. *Ongoing* Analysing fault current data from commissioned GFM BESS. *Est. June 2026* Validate GFM models in software HiL testing. *Est. June 2026* Type 2 trial “GFM protection-quality fault current”. *Est. completion 2027* OEM studies		
System strength – Efficient level of system strength	Quantify the contribution of GFM to stable GFL operation, comparing to synchronous condensers. *Est. June 2026*	Transgrid technical performance specification for procurement of stable voltage waveform. *2024* 8 GW pipeline from GFM BESS procurement in system strength RIT-Ts. *Est. 2032*	
Synthetic inertia	Methodologies for quantifying inertia. *Est. June 2026* Hardware-in-the-loop validation. *Est. 2027*	ARENA GFM BESS inertia development. *2022-2023*	
System Restart Ancillary Services	Type 2 Trial “Black start capability from IBR”. *Est. completion 2027*		
Access standard and commissioning	Create and trial a standardised HiL precommissioning test procedure to validate GFM-BESS functionality prior to grid connection. *Est. 2027* OEM advocacy and collaboration for improved access standards	Access Standards Review considering a GFM category and making some GFM requirements enforceable. *Rule Change proposal to AEMC - Est. June 2026*	

Key: Current AEMO activities | Other current activities

10.2 Hybrid gas turbine-synchronous condensers

Key messages

- Gas turbines (GTs) fitted with clutches (at design or retrofit) can act as synchronous condensers, providing security services even when not generating power.
- The 2024 ISP optimal development path included considerable investment in GTs in the 2030s. It may be prudent to deliver these projects earlier with clutches and potentially black start capability to provide security services ahead of being needed for energy reliability.

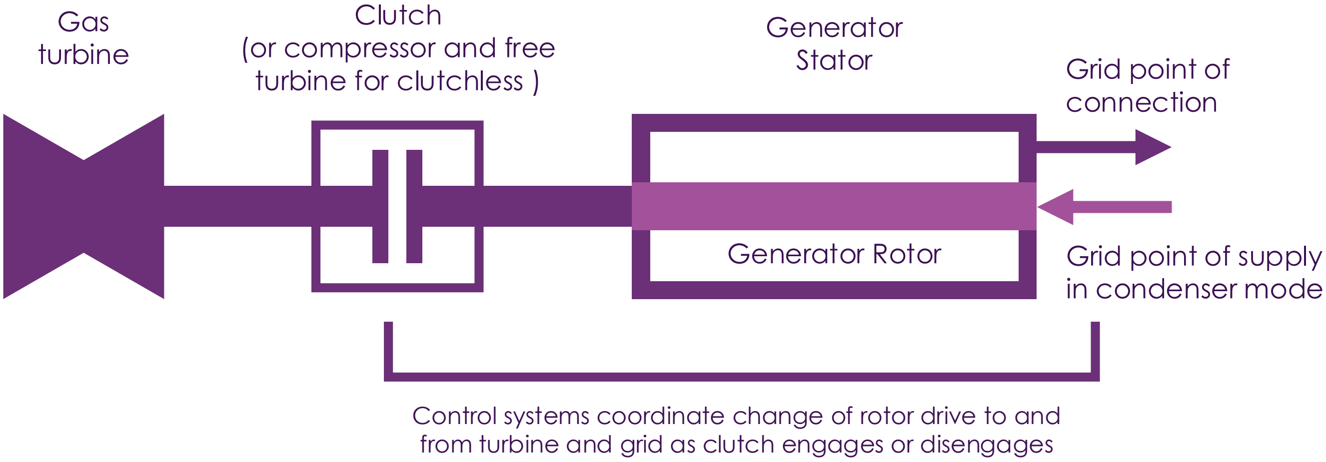
Key actions

- AEMO encourages investors to consider clutches on all new GTs, and retrofits of existing GTs should also be considered.
- Policy reform may be required to incentivise investment in co-optimised energy and security assets.

10.2.1 Context

Hybrid gas turbine-synchronous condensers (hybrid GT-synchronous condensers) are gas turbines with the ability to disengage power generation and instead draw power from the network to keep the generator spinning as a synchronous condenser without drawing fuel. This allows a single synchronous unit to act both as a power generator and to provide system strength, inertia, and reactive power for system security purposes, even when providing no energy to the system. **Figure 25** shows an indicative diagram of a clutched hybrid GT-synchronous condenser.

Figure 25 Hybrid open cycle gas turbine (OCGT) clutch diagram



The 2024 ISP highlighted a need for over 3 GW of flexible turbine capacity by 2035 for firming purposes. At the same time, multiple system strength RIT-Ts in each region highlight the need for additional system strength, inertia, and reactive power capability. Hybrid GT-synchronous condensers offer the opportunity to efficiently deliver on energy and system security needs in a single facility[112].

10.2.2 Latest status

Hybrid GT-synchronous condenser capability is most easily fitted on open cycle gas turbines (OCGTs), also referred to as simple cycle gas turbines. Adding clutch capability to a new gas turbine during the design phase adds a modest cost to the final plant.

Clutches can also be retrofitted to existing gas turbines, with potential to significantly reduce system costs by utilising existing plant infrastructure, an example of which was completed on Townsville Power Station's gas turbines in 2025[113]. Retrofitting feasibility is highly plant-dependent and affected by existing configuration and plant construction[114]. Existing generators were generally not built for hybrid GT-synchronous condenser purposes, and retrofit feasibility should be assessed on a per plant basis, noting benefits stemming from utilisation of existing generators that often have large MVA capacities and shorter lead times for construction. Operating and maintenance costs compared to purpose-built plant require additional consideration.

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[112] See *Repurposing existing generators as synchronous condensers* from DigSilent, at https://arena.gov.au/assets/2023/06/repurposing-existing-generators-as-synchronous-condensers-report.pdf.

[113] See https://www.powerlink.com.au/sites/default/files/2024-01/Request%20for%20Power%20System%20Security%20Services%20-%20Final%20Report%20Part%202%20-%20System%20Strength%20at%20Gin%20Gin.pdf.

[114] See *Repurposing existing generators as synchronous condensers* from DigSilent, at https://arena.gov.au/assets/2023/06/repurposing-existing-generators-as-synchronous-condensers-report.pdf.

Security services – including system strength, inertia, and reactive power support – are provided both during GT power generation mode and synchronous condenser mode, but cannot be provided during the switch over from one mode to another. These switching times are typically in the range of five to 30 minutes, depending on turbine size and configuration. This switching also causes some increased wear on the plant. These factors need to be considered in operational procedures and commercial business cases.

10.2.3 AEMO's forward plan

AEMO encourages investors to consider the addition of clutches to all new GTs, and retrofits to also be considered. AEMO recognises that policy reform may be required to incentivise investment in co-optimised energy and security assets.

Future hydro and gas projects present a strategic opportunity to incorporate black start capability, supporting system restoration as coal retires and aligning with AEMO's evolving System Restart framework (see Section 8.2 for context).

10.3 Large inverter-based loads

Key messages

- Large inverter-based loads (LIBL), particularly large data centres, are projected to rapidly become major loads on the system, with over 10 GW lodging connection enquiries (some single data centres exceeding 1 GW) in New South Wales by the end of 2024-25[115].
- Without coordinated planning and careful connection, LIBL present system security risks including through power system oscillations, sudden load loss or ramping, transient stability, and increased inertia requirements.
- LIBL also present opportunities including provision of demand response and delivery of stable load blocks during system restart and MSL.

Key actions

- AEMO is contributing to a workstream under the Energy and Climate Change Ministerial Council, together with officials and market bodies, to harness the opportunities from the growth in data centres while managing the implications for Australia's electricity systems.
- AEMO is proposing a rule change to the access standards for large loads[116, 117]. The rule change, due for finalisation in 2026, will require collaboration between DNSPs, TNSPs and AEMO and LIBL operators to implement.
- AEMO is studying LIBL security risks in the 2026 GPSRR.
- AEMO is collaborating with the International System Operators Network (ISON) on best practice.

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[115] TransGrid (2025) *Transmission Annual Planning Report,* at https://www.transgrid.com.au/media/xgun43m0/2025-transmission-annual-planning-report_update_081025.pdf.

[116] AEMO (2024) *Overview of rule change proposals to improve NEM access standards,* at https://www.aemc.gov.au/sites/default/files/2024-04/New%20rule%20change%20proposal%20-%20AEMO%20-%20Improving%20the%20NEM%20access%20standards%20-%2020240403%20-%20Overview.pdf.

[117] AEMO (2024) *Request for standard rule April 2024*, at https://www.aemc.gov.au/sites/default/files/2024-04/New%20rule%20change%20proposal%20-%20AEMO%20-%20Improving%20the%20NEM%20access%20standards%20-%2020240403%20-%20Attachment%20B.PDF.

10.3.1 Context

LIBL, particularly data centres, are rapidly becoming a significant proportion of total power and energy demand in major power systems around the world[118,119]. International experience has demonstrated LIBL can cause challenges for power systems – see **Table 22**.

In the NEM, AEMO now considers data centres as a distinct category in planning frameworks such as the ISP and ESOO. The 2025 ESOO *Step Change* scenario saw data centres comprising up to 10% of NEM demand in 2035. Independent forecasts, commissioned by AEMO, suggest Sydney and Melbourne are likely see the majority of growth due to commercial and connection proximity[120].

Table 22 Experiences of LIBL impacts in Ireland and the USA

Ireland	United States of America
EirGrid has observed[A]: - **LIBL cyclical load ramping (10's of MW) during normal operation, impacting system frequency and potentially exciting system oscillatory modes.** - **Power system faults or voltage fluctuations causing the sudden loss of hundreds of megawatts of LIBL, resulting in large frequency excursions and rate-of-change-of-frequency (RoCoF) as high as 0.2 Hz/s.** - **With LIBL capacity having reached approximately 10% of peak load the impact of such load loss events contingencies can be greater than 30% of their load at times of minimum demand.**	ERCOT experienced[B] 24 load loss events over 100 MW involving LIBL from November 2023 to January 2025, the largest of which was 423 MW. The Eastern Interconnection experienced a major LIBL loss event of approximately 1,500MW in July 2024[C] caused by a system disturbance (line fault and subsequent reclose attempts). NERC created the Large Load Taskforce (LLTF) in August 2024 to understand large load phenomena, risks to system security, and recommend regulatory changes to manage risk for LIBL. The LLTF will publish a gap-analysis of practices, requirements, and reliability standards for large loads. This work will feed into the subsequent publication of a reliability guidelines to address identified shortfalls in planning, processes, and interconnection requirements.

A. EirGrid Group (2024), *EirGrid Experience with Large Loads Interconnection*, at https://www.esig.energy/wp-content/uploads/2025/03/EirGrid-Experience-with-Large-Loads-Interconnection-.pdf.
B. Oxford Economics (2025), *Data Centre Energy Demand*, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/oxford-economics-australia-data-centre-energy-consumption-report.pdf.
C. NERC Large Loads Task Force (2025*), Characteristics and Risks of Emerging Large Loads*, at https://www.nerc.com/comm/RSTCReviewItems/3_Doc_White%20Paper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf.

10.3.2 Latest status

LIBL and data centres differ from other traditional large power system loads, such as smelters, in several key aspects including a high concentration of inverter load, advanced Uninterrupted Power Supplies (UPSs), unpredictable load profiles, and individual load sizes that can exceed the largest traditional large loads in the NEM. As **Table 23** shows, if not well integrated at time of connection, they have potential to pose significant risks to system security, but also, present opportunities.

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[118] EirGrid/SONI (2023) *Ten-Year Generation Capacity Statement*, forecast up to 30% of energy demand by 2032, at https://cms.eirgrid.ie/sites/default/files/publications/19035-EirGrid-Generation-Capacity-Statement-Combined-2023-V5-Jan-2024.pdf.

[119] Lawrence Berkley National Laboratory (2024) *2024 United States Data Center Energy Usage Report,* forecast up to 12% of US energy consumption, or 580 TWh (132 GW at 50% capacity utilisation) by 2028. See https://escholarship.org/content/qt32d6m0d1/qt32d6m0d1.pdf.

[120] Oxford Economics (2025), *Data Centre Energy Demand*, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/oxford-economics-australia-data-centre-energy-consumption-report.pdf.

Table 23 System security impacts from data centres

Impact	Description
Fault ride-through	Data centres typically prioritise availability and up-time of their processes and configure their on-site infrastructure accordingly. Many data centres feature advanced uninterruptable power supplies that combine on-site backup generation systems with batteries and/or flywheels to ensure they remain in service during power system disturbances. International experience demonstrates their ability to transfer their load to local backup power can result in the un-coordinated load loss of hundreds of megawatts as they fail to ride through power system disturbances. Fault ride-through performance is a major concern with LIBL connections internationally. It has been observed that in addition to voltage and frequency metrics, LIBL backup power systems may utilise disturbance counting to determine when to disconnect from the grid and switch to back-up generation. This can make modelling and predicting their collective behaviour during disturbances difficult. If left unchecked, poor and unpredictable ride through performance of LIBL may result in cascading consequences for the power system, similar to the consequences of the wind-turbine ride-through settings that contributed to the South Australian system black event in 2016.
Demand ramping capability	LIBL can ramp their demand bidirectionally at the rate of hundreds of megawatts per minute[A], presenting a significant burden on system frequency regulation and contingency resources. Additionally, large, sudden changes in demand also affect reactive power margins in the system, cause over/under voltage conditions, frequency or voltage instability, and the potential for subsequent load or generation loss, or voltage collapse.
Erratic load profile and oscillations	Internationally, erratic load profile from LIBL are being observed as a result of significant growth of artificial intelligence (AI) services. Observed load profiles for data centres involved in AI computational processes can rapidly oscillate – in one example by 40%[A] – within seconds during different processing phases. This load behaviour requires even greater active and reactive power reserves to manage system security and may cause greater power system oscillations by exciting system oscillatory modes.

A. NERC Large Loads Task Force (2025*), Characteristics and Risks of Emerging Large Loads*, at https://www.nerc.com/comm/RSTCReviewItems/3_Doc_White%20Paper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf.

Opportunities

LIBL, including data centres and electrolysers, also present opportunities for the NEM. For example, LIBL may:

- offset minimum system load conditions by increasing demand (see Section 9.1),
- be contracted to provide stable load blocks for SRAS (see Section 8.2),
- provide demand response capacity by transferring their loads to backup power, and
- actively control their loading and participate in demand response or FCAS without transferring to backup power.

10.3.3 AEMO's forward plans

Table 24 outlines the approaches AEMO is pursuing to mitigate potential risks and leverage the opportunities of LIBL.

Table 24 AEMO's approaches to managing LIBL in the NEM

Approach	Description
Knowledge sharing	Internationally, AEMO is a contributor to the International System Operators Network (ISON) in collaboration with CAISO, ERCOT, Energinet, NESO, and EirGrid. AEMO has established a program of work to understand the risks and potential benefits of LIBL growth, and international best-practice for connections. The work of this program will advise on future AEMO efforts regarding large loads, such as improved access standards or market reform.
Reform	In 2024, AEMO initiated a rule change proposal "Improving the NEM access standards – Package 2" as part of its five-yearly Access Standards Review[A,B]. This proposal incorporated initial measures towards establishing appropriate access standards for large loads such as a requirement to record ride-through capability. At the time, it was acknowledged that a more detailed understanding of the capabilities of large load technologies was required to inform further access standard changes. AEMO and the AEMC continue to collaborate on this rule change, due to be finalised in 2026. An industry technical working group has been established to further explore issues including: • large load classifications and thresholds,

Approach	Description
	- disturbance ride-through requirements, and - modelling requirements In parallel to this rule change, AEMO is undertaking power systems studies to assess the contingency and forced oscillation risks. AEMO is also engaging closely with OEMs and developers to better understand: - technology capability and limitations, - operational behaviour, and - commercial drivers.
Forecasting and research	The 2026 GPSRR will feature a focused data centre study to complement AEMO's planning function, exploring the system security considerations of LIBL. The ISP and ESOO are now including data centres as a separately forecasted demand category in their methodology.

A. AEMO (2024), *Overview of rule change proposals to improve NEM access standards*, at https://www.aemc.gov.au/sites/default/files/2024-04/New%20rule%20change%20proposal%20-%20AEMO%20-%20Improving%20the%20NEM%20access%20standards%20-%2020240403%20-%20Overview.pdf.
B. AEMO (2024), *Request for standard rule April 2024*, at https://www.aemc.gov.au/sites/default/files/2024-04/New%20rule%20change%20proposal%20-%20AEMO%20-%20Improving%20the%20NEM%20access%20standards%20-%2020240403%20-%20Attachment%20B.PDF.
C. DCCEEW/ECMC (2025), *National Electricity Market wholesale market settings review,* at https://storage.googleapis.com/files-au-climate/climate-au/p/prj36f491a5284dc4c74959e/page/NEM_Review_Draft_Report_August_2025_Final_2.pdf.

10.4 Emerging technologies

Key messages

- Early engagement with emerging technologies will help manage challenges and capture opportunities for system security.

Key actions

- AEMO engages in technology developments through its Engineering Roadmap activities, research engagement Program, use of Type 2 Transitional Services, and participation in ISON.

This section describes some emerging technologies that may impact system security in the medium and long term (Horizon 3 period). AEMO is monitoring these technologies to better understand their potential impacts and benefits. These technologies are categorised in **Table 25**.

Table 25 Emerging technologies that may potentially contribute to system security

Category	Description	Examples
Synchronous generators with low- or zero-emissions energy sources	New energy storage or alternative fuel technologies with a synchronous generation stage may support system security similarly to existing thermal generators. Their support is subject to their active power generation, which may be constrained by their storage capacity, ramp rates, and power system demand.	- Compressed air/CO2 storage - Liquid air storage - Concentrated solar thermal - Thermal storage - Clutchless synchronous generators - Hybrid hydrogen power plant - Alternative fuels e.g. biomass, ammonia
Advanced power electronics	Power electronics provide voltage stability, reactive power support and synthetic inertia to networks.	- E-STATCOM - Superconducting magnetic energy storage (SMES)

Category	Description	Examples
Advanced monitoring, protection and control systems	Advanced monitoring systems, data management, protection and control methods enhance the visibility and controllability of the power system, improving the ability to operate flexibly within the technical envelope, increase asset utilisation, enhance dispatch efficiency and mitigate operational risks. This is critical in a future of highly variable generation and load that requires a prompt and well controlled response. Deployment of advanced monitoring and data analysis has the potential to enhance system security and leverage the full potential of the assets on the ground, reducing the need for capital-intensive equipment.	• Wide Area Monitoring, Protection and Control • Adaptive protection and control schemes • AI algorithms and Machine Learning • Micro Phasor Measurement Units in medium voltage (MV) system • Advanced demand response • Advanced tools for power system analysis and/or optimisation • Fast system restart
Transmission	New approaches to transmission infrastructure could improve system security performance.	• Superconductors • Virtual transmission lines • Hybrid AC/DC overhead lines

AEMO contributes to the evolution of technologies through a variety of engagements. This includes procuring trials of new technology through the Type 2 Transitional Services framework (see Section 2.3.2), participating in CSIRO research initiatives, such as providing Topic Leads for the Australian Research-Power System Transformation initiative, and supporting ARENA-funded projects through participation in advisory committees and through secondments of university researchers into AEMO as part of ARENA-funded projects.

11 Horizon 3 and next steps

In this year's *Transition Plan for System Security*, the transition planning horizon (Horizon 2) has been extended from five to 10 years to reflect stakeholder feedback on the importance of transition planning with sufficient outlook to enable investment decision-making and delivery.

In the 2024 *Transition Plan for System Security*, the five-to-10-year period was presented as Horizon 3, and contained commentary on screening for upcoming transition points as well as priority work to define capabilities and progress understanding of the future power system. Screening for upcoming transition points is now undertaken as part of the (extended) Horizon 2 regional transition plans in Part B, with the efforts to progress understanding of what is needed to maintain power system security in a low- or zero-emissions power system now detailed in Part C.

Horizon 3 is now defined as the period starting 10 years from the date of *Transition Plan for System Security* publication, and is intended to focus on identifying and framing risks and opportunities to prepare for anticipated power system conditions into the future, including:

- studies and trials that progress readiness of emerging technologies to meet future power system needs, and
- future-back analysis to enhance understanding of the needs of a low- or zero-emissions power system.

AEMO intends to merge Engineering Roadmap reporting into the *Transition Plan for System Security* from 2026 to provide an integrated view of the future of power system security and the knowledge and capabilities required to support it. This merge is intended to provide coverage of the above two areas of focus, as well as highlighting progress toward previously committed Engineering Roadmap activities.

AEMO recommends stakeholders refer to the *Engineering Roadmap to 100% Renewables*[121] and the *Engineering Roadmap FY2026 Priority Actions*[122] reports for further information on this substantive program of work.

Further to this, in 2025 AEMO published its Research Priorities[123]. This document outlines priority research topics that AEMO identified as aligning with its strategic priority of Navigating the Energy Future[124], and which AEMO is interested in progressing in collaboration with the research community.

Both these bodies of work are intended to play a role in informing the development of Horizon 3 in the 2026 *Transition Plan for System Security*.

Coordinated and collaborative engagement across the entire energy sector is vital to deliver an effective, efficient, and timely *Transition Plan for System Security* and energy transition. Further detail on AEMO's forward stakeholder engagement plan is in Section 2.6.

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[121] At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables.pdf.

[122] At https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/engineering-roadmap-fy2026-priority-actions-report.pdf.

[123] At https://www.aemo.com.au/initiatives/major-programs/research-priorities.

[124] At https://www.aemo.com.au/about/corporate-governance/corporate-plan.

Abbreviations

Term or acronym	Term in full	Term or acronym	Term in full
ACEREZ	Acciona, Cobra, Endeavor Energy Renewable Energy Zones	**LDS**	Long duration storage
AEMC	Australian Energy Market Commission	**LIBL**	Large inverter-based loads
AEMO	Australian Energy Market Operator	**LSBS**	Large scale battery storage
AER	Australian Energy Regulator	**LV**	Low voltage
ARENA	Australian Renewable Energy Agency	**MSL**	Minimum system load
AS/NZ4777.2	Australian Standards for Grid connection of energy systems via inverters – inverter requirements	**MSOL**	Minimum safe operating level
ASR	Access Standards Review	**MVA**	Megawatt amp/s
AVP	Australian Victorian Planner	**MW**	Megawatt/s
BESS	Battery energy storage system/s	**MWs**	Megawatt-seconds
BSG	Black start generator	**NEM**	National Electricity Market
CEC	Clean Energy Council	**NEMOC**	National Electricity Market Operations Committee
CER	Consumer energy resources	**NER**	National Electricity Rules
CIS	Capacity Investment Scheme	**NMAS**	Non-market ancillary services
CRI	Connections Reform Initiative	**NSCAS**	Network support and control ancillary services
CVT	Capacitive Voltage Transformer	**NSP**	Network service provider
CWO	Central-West Orana (REZ)	**OCGT**	Open cycle gas turbine
DER	Distributed energy resources	**OEM**	Original equipment manufacturer
DNSP	Distribution Network Service Provider	**ONSG**	Other non-scheduled generation
DOE	Dynamic operating envelope	**Other NMAS**	Any of an *inertia network service*, a *system strength service*, a *market ancillary service* or an *NMAS* which is not a *transitional service*
DPV	Distributed photovoltaic is a type of CER that is a small-scale source of local solar generation that connects to the grid at the distribution level	**OTP**	Operations Technology Program
DPVNSG	Distributed photovoltaic non-scheduled generator	**OTR**	Operational Technology Reform Program
DSO	Distribution System Operator	**PACR**	Project Assessment Conclusions Report
DSP	Demand side participation	**PADR**	Project Assessment Draft Report
EAAP	Energy Adequacy Investment	**PASA**	Project Assessment of System Adequacy
EJPC	Executive Joint Planning Committee	**PEC**	Project Energy Connect
EMT	Electromagnetic transient	**PFR**	Primary frequency response
EPIR	Electric Power Research Institute	**POE**	Probability of exceedance
ESOO	Electricity Statement of Opportunities	**pu**	Per unit
EVM	Emergency Voltage Management	**PVNSG**	Photovoltaic non-scheduled generation
EV	Electric vehicle	**QNI**	Queensland – New South Wales Interconnector

Term or acronym	Term in full	Term or acronym	Term in full
FCAS	Frequency control ancillary services	**RAS**	Remedial Action Scheme
FELs	Flexible Export Limits	**REZ**	Renewable Energy Zone
FFR	Fast Frequency Response	**RIT-T**	Regulatory Investment Test for Transmission
FOS	Frequency Operating Standard	**RoCoF**	Rate of change of frequency
FY	Financial Year	**RSS**	Restoration support service
GFL	Grid-following	**SCADA**	Supervisory Control and Data Acquisition
GFM	Grid-forming	**SCR**	Short Circuit Ratio
GIA	Generator Interim Access	**SRAS**	System Restart Ancillary Services
GPG	Gas Powered Generation	**SRS**	System Restart Standard
GPS	Generator Performance Standards	**SSSP**	System Strength Service Provider
GPSRR	General Power System Risk Review	**SSRS**	System Strength Remediation Scheme
GSDs	Generation Signalling Devices	**TAPR**	Transmission Annual Planning Report
GSOO	Gas Statement of Opportunities	**TIPSB**	Torrens Island Power Station B
GT	Gas Turbine	**TNSP**	Transmission Network Service Provider
GW	Gigawatt/s	**TPSS**	Transition Plan for System Security
GWh	Gigawatt hour/s	**TSPO**	Transitional Services Procurement Objective
HIL	Hardware-in-the-loop	**UFLS**	Under frequency load shedding
IBR	Inverter-based resources	**UPS**	Uninterrupted power supplies
IPRR	Integrating Price Responsive Resources	**VPP**	Virtual power plant
ISF	Improved Security Framework	**VRE**	Variable renewable energy
ISON	International System Operator Network	**VSR**	Voluntary Scheduled Resource
ISP	Integrated System Plan	**VTP**	Victorian Transmission Planning
JSSC	Jurisdictional System Security Coordinator	**VRET**	Victorian Renewable Energy Target
kV	Kilovolt/s	**WEM**	Wholesale Electricity Market
		WRL	Western Renewables Link