AEMC Australian Energy Market Commission

Australian Energy Market Commission

RULE

Rule determination

Efficient provision of inertia

Proponent

Australian Energy Council

9 October 2025

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About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the Traditional Custodians of the many different lands across Australia on which we live and work. The AEMC office is located on the land of the Gadigal people of the Eora nation. We pay respect to all Elders past and present, and to the enduring connection of Aboriginal and Torres Strait Islander peoples to Country.

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Summary

1 The Commission has decided not to make a final rule to introduce a new operational procurement mechanism for inertia, in response to the rule change request submitted by the Australian Energy Council. While the Commission considers that the operational procurement of inertia has merit in principle and could achieve benefits for consumers in the future, our analysis has shown that there is unlikely to be net benefits in the near term.

2 Our final decision benefits consumers by avoiding implementation costs for a new operational procurement mechanism that is currently unlikely to deliver net benefits to consumers. We consider that the existing inertia and system strength frameworks, recently enhanced by the *Improving security frameworks for the energy transition* (ISF) rule, will deliver benefits and should have time to play out before initiating further change.

3 In addition, we do not miss out on benefits by deferring a potential new operational procurement mechanism, because technical work that would be required to underpin operational procurement is already progressing. This work includes advancements in real-time inertia measurement, the operational management of inertia through dynamic constraints, and refinements to quantifying synthetic inertia.

4 In order to continually and proactively monitor conditions, the Commission will task the Reliability Panel with monitoring system conditions through its annual Reliability and Security Report (RASR, formerly known as the Annual Market Performance Review) to identify when operational procurement could become beneficial.

5 The Commission also considers that recent reforms and existing system security frameworks can continue to deliver benefits to consumers. While we recognise there are opportunities to deliver benefits through an improved application of existing frameworks, we have not adopted stakeholder suggestions to amend or institute governance frameworks relating to system security. Our final determination sets out the Commission's assessment of stakeholder feedback and suggestions for regulatory changes to broader system security frameworks.

The Commission considers that the operational procurement of inertia would not provide net benefits at this time

6 To facilitate our analysis, we separated inertia demand into two components: **minimum inertia** and **additional inertia:**

- **minimum inertia** is the amount of inertia required for secure operation of the power system at any time
- **additional inertia** is any inertia above the minimum level that may provide economic benefits to consumers by lowering the total cost of dispatch.

7 We consider that minimum inertia is not currently suitable for operational procurement due to the very high costs of undersupply combined with investment uncertainty for potential new entrants. In addition, investments that are needed for system strength will deliver large amounts of inertia as an unavoidable co-benefit, with minimal costs to consumers.

8 In the most likely future market scenarios, the benefits of operationally procuring additional inertia would not outweigh the upfront and ongoing costs of designing, implementing and operating this new market.

9 Based on current information, the Commission considers that the expected inertia supply will

greatly exceed minimum requirements over the foreseeable horizon, due to the work underway to meet system strength requirements. This includes the installation of synchronous condensers, conversion of synchronous generators to synchronous condensers and grid forming batteries entering into contracts with TNSPs to provide system strength for the secure operation of the power system. The cost and timing of these investments would not be avoided or offset by a real-time market for inertia.

10 Although these solutions for system strength are not being supplied explicitly for inertia, their inertia contribution is expected to be sufficient in the near term, contributing to future inertia supply.

11 In addition, we consider that future credible contingencies are not likely to drive increases in minimum inertia demand. AEMO has advised that there would be unacceptable engineering risks associated with allowing larger credible contingency sizes, which would be mitigated through control schemes.

We will not miss out on benefits by waiting because technical work and system security reforms are still progressing

12 An important aspect of our final decision is that we do not lose the potential benefits that could arise from operational procurement of inertia in the future. This is because:

- AEMO is already progressing technical work that would be preconditions to the implementation of a future real-time market for inertia. In other words, little to no time would be lost if work on a real-time inertia market were to commence now, versus waiting for the required technical work that is already underway to progress further.
- We preserve the option value of implementing a new procurement mechanism of inertia, if and when we are more confident that it will deliver net economic benefits to consumers
- Preserving the option value of determining the best enduring approach to procure inertia means that we can better incorporate new findings, new technologies and the future state of the power system.

13 Recent reforms from the *Improving security frameworks for the energy transition* rule means that TNSPs are currently procuring and contracting with system security providers. We do not consider that significant changes to the current framework would promote the NEO as it could increase security contracting costs, may result in consumers incurring costs for tools that may not be used, and would leave industry with an unclear direction as to how to procure and provide inertia and system strength throughout the transition, risking system security.

The Reliability Panel will monitor inertia-related metrics in its annual Reliability and Security Report

14 Our analysis indicated that operational procurement of inertia could provide net benefits to consumers, but under different conditions that are currently not expected to materialise. However, these conditions could evolve in an unexpected way, which would increase the benefits of operationally procuring inertia, leading to net benefits.

15 For example, if there is (or there is expected to be):

- a significant increase in minimum inertia requirements
- a rise in the expected costs of meeting inertia needs through the current inertia framework (with obligations set to commence from 1 December 2027),

- a sustained increase in contingency FCAS prices, primarily for the 1-second service
- an increase in the number or value of RoCoF-related constraints, including any new constraints that AEMO may formulate to maintain secure operation,

then the potential benefits of a real-time inertia market would increase.

16 To ensure that we do not miss out on potential benefits, the Commission will task the Reliability Panel to monitor these inertia-related metrics through its annual Reliability and Security Report (RASR, formally known as the Annual Market Performance Review).

17 The Commission will amend the Terms of Reference for the RASR so that the Panel must publicly report on the metrics above (and any other metrics that it considers suitable), comment on the evolution of the metrics and current expectations, and optionally, comment on what the influence of any changes could have on the benefits of operationally procuring inertia.

18 If the Panel comes to a view that the operational procurement of inertia should be reconsidered, it could choose to submit a rule change request to the Commission. Any decision on implementing a new procurement mechanism in the NER would remain a decision for the Commission through a future rule change process.

We considered stakeholder feedback on broader system security frameworks, and consider that an improved application of existing frameworks will continue to deliver benefits to consumers

19 In our draft determination, we suggested ways to improve how existing frameworks are being applied in practice, such as:

- encouraging AEMO to increase its visibility of its technical work through its Transition Plan for System Security (TPSS)
- leveraging the transitional services framework to support innovation and future procurement readiness
- encouraging TNSPs and the AER to strengthen transparency and technology neutrality through the RIT-T framework and TNSP procurement decisions.

20 AEMO is developing its second TPSS for release in December 2025, which will provide substantial information on its plan to manage system security throughout the transition. Additionally, AEMO intends to begin procurement for Type 2 contracts under the transitional services framework.

21 Since the publication of our draft determination, TNSPs have continued negotiations and begun new procurement processes to enter into contracts with non-network options to provide system security.

22 In response to our draft determination, we received stakeholder suggestions for amendments that could be made to these existing frameworks to promote accountability, competition and transparency. However, after thoroughly assessing all stakeholder feedback and examining the existing frameworks, we do not consider that amendments to these frameworks are required through this rule change process.

23 We consider that additional obligations, prescriptive processes or new governance frameworks are not likely to provide clear benefits to consumers, and in some instances, may be duplicative or result in unintended consequences. For example, the *Improving security frameworks for the energy transition* rule includes detailed content and consultation requirements, and only one TPSS has been published since the rule has commenced. We consider that more information and editions of the TPSS would be required before considering implementing new rules requirements for the

TPSS.

We assessed our decision against five assessment criteria, taking stakeholder feedback into account

24 The Commission has considered the NEO[1] and the issues raised in the rule change request, and assessed the final rule against five assessment criteria outlined below.

25 The final determination will contribute to achieving the NEO by:

- **Safety, security and reliability** - The final determination will support secure and reliable power system operation by retaining the long-term procurement framework and enabling improvements to its application. The Commission is satisfied with our analysis which suggests that operational risks can continue to be managed under current frameworks, particularly as technical tools and system capabilities continue to improve.
- **Emissions reduction** - The Commission considers that existing frameworks sufficiently support emissions reduction objectives when providing inertia. Recent reforms have enabled TNSPs to procure synthetic inertia, and AEMO's updated Inertia Requirements Methodology now incorporates the contribution of fast frequency response in determining minimum inertia needs.
- **Principles of market efficiency** - The final determination promotes market efficiency by maintaining a framework that enables efficient procurement decisions, while avoiding the costs and risks of implementing an operational procurement mechanism for inertia that does not have net benefits under current and expected system conditions.
- **Innovation and flexibility** - The final determination preserves the option of implementing real-time procurement for inertia in the future, when the expected benefits may increase, and our knowledge of the future state of the power system becomes clearer. It also supports innovation and flexibility of existing frameworks, such as AEMO's ability to enter into Type 2 contracts to trial innovative approaches to managing system security.
- **Implementation considerations** - The final determination allows time for related reforms and technical work programs to progress, while preserving the flexibility to revisit operational procurement for inertia if system conditions warrant it. This approach supports a more informed, coordinated and cost-effective implementation pathway for the future.

1 Section 7 of the NEL.

Contents

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Figures

1 The Commission has made a final determination

This final determination is to not make a final rule in response to a rule change request submitted by the Australian Energy Council (AEC), which sought to introduce a real-time market for inertia in the NEM.[2] The rule change request identified a need to reconsider the existing inertia framework in the context of declining synchronous inertia and associated system needs, as synchronous coal and gas generators retire. The proponent considered the introduction of an ancillary service spot market for inertia as an appropriate solution to meet long-term power system needs.[3]

This final determination sets out the Commission's assessment of the benefits and costs for consumers of a real-time procurement mechanism for inertia and the rationale for its decision to make no rule. We also respond to stakeholder comments and views that were expressed through submissions to the draft determination and through other consultation throughout the rule change process.

For the purpose of this determination, the term 'operational procurement' refers to a mechanism that procures system services in operational timeframes, which ranges from intra-day to real-time dispatch. See Figure 3.9 for examples of operational procurement mechanisms.

1.1 Our final decision is not to implement a real-time inertia market at this time

The Commission has made a final determination not to implement the proposed market at this time. The Commission supports the operational procurement of inertia in principle and considers that it may provide market and system benefits under the right conditions. However, the Commission considers that the conditions for realising benefits from operationally procuring inertia do not currently exist.

As set out in the draft determination,[4] and in this determination, the Commission assessed the future supply and demand for inertia. We split our analysis of inertia into two use cases of inertia, minimum inertia and additional inertia (see section 3.1 and section 3.2 for more information). Using the current plans of NSPs to meet system strength obligations as a proxy for expected investments in inertia, the analysis shows that minimum inertia needs will likely be met in the near term through co-provision from system strength investments, without requiring a new procurement mechanism. In addition, expected inertia supply from these system strength investments is also expected to significantly exceed minimum requirements, with these requirements also not likely to increase from present-day levels. For additional inertia the commission found that the benefits of operational procurement of additional inertia, with respect to investment in and the use of electricity system assets, is unlikely to exceed the costs to consumers and other stakeholders to implement a spot market given current assumptions.[5]

The Commission acknowledges that these outcomes are sensitive to assumptions, including the timing and scale of how TNSP's meet their system strength obligations, and the potential for earlier-than-expected retirement of synchronous generation. Although our analysis is based on TNSP RIT-Ts, which currently are proposing to use synchronous condensers to meet minimum system strength requirements given current engineering understanding, the Commission expects

2 AEC, Inertia Spot Market Rule Change Request, December 2021.

3 For more information see AEMC, Efficient provision of inertia, Consultation paper, 2 March 2023; AEC, Inertia Spot Market Rule Change Request, 15 December 2021.

4 AEMC, draft determination, chapter 3.

5 See AEMC, draft determination, chapter 3.2 for more information.

that a mix of grid-forming inverters, synchronous machines and any other future technologies will provide both system strength and inertia in the future.

The Commission considers our expected outlook to be a reasonable view based on current information, while recognising it is subject to uncertainty. This outlook was used to determine whether operational procurement would offer additional benefits in circumstances where foreseeable inertia needs are expected to be met through meeting the obligations under the system strength framework.[6]

Under the conditions of our base case scenario,[7] the modelling indicates that short-term benefits would be modest, primarily reflecting reductions in frequency control costs during limited periods. Additionally, our analysis found that the benefits would not outweigh the upfront and ongoing costs of designing, implementing and operating an inertia spot market. These findings led the Commission to conclude that, under current system conditions, operational procurement of inertia would not deliver net benefits in the short to medium term.

The Commission considers that a decision not to implement operational procurement at this time does not result in any loss of benefits for consumers, as the current frameworks are expected to continue delivering value and support system learning over time. This ongoing technical work which we consider will allow for operational procurement of inertia in the future, is discussed in more detail in section 3.7.1.

Further detail on the Commission's analysis and stakeholder feedback relating to a potential operational procurement mechanism for inertia is provided in Chapter 3.

1.1.1 The Reliability Panel will monitor system conditions and the Commission will reconsider operational procurement when it becomes beneficial

Despite the current assessment that operational procurement of inertia will not provide a net benefit now, the Commission considers that, if certain system conditions change, operational procurement could deliver net benefits in the future. Therefore, the Commission will task the Reliability Panel with monitoring these system conditions through its annual Reliability and Security Report (RASR, formally known as the Annual Market Performance Review) to identify when operational procurement could become beneficial.

To facilitate this oversight, the Commission will update the Reliability Panel's Terms of Reference for its RASR to explicitly set out the metrics that the Reliability Panel should monitor and report annually, such as:

- minimum inertia requirements (that is, minimum inertia demand)
- the cost of long-term procurement for minimum inertia
- the typical prices of the 1-second contingency FCAS markets
- the marginal value of RoCoF-related operational constraints.

If the following changes to the metrics occur, or are expected to occur, then operational procurement may become more likely to deliver net benefits to consumers:

- a significant increase in minimum inertia requirements
- a rise in the cost of meeting inertia needs through the current inertia framework (with obligations set to commence from 1 December 2027),

6 AEMC, Efficient Management of system strength on the power system, Rule determination, 21 October 2021; AEMC, Improving security frameworks for the energy transition, Rule determination, 28 March 2024.

7 For more details on the key assumptions used in our most likely scenario, see Table 3.1 of the draft determination.

- a sustained increase in contingency FCAS prices, primarily for the 1-second service
- an increase in the number or value of RoCoF-related constraints, including any new constraints that AEMO may formulate to maintain secure operation.

If the Reliability Panel considers the conditions have changed such that the benefits of introducing an operational procurement mechanism for inertia may have materially increased, it could choose to propose a rule change to the Commission for this to be considered more fully. However, the Reliability Panel will not determine whether the conditions justify implementing operational procurement of inertia. Any decision to proceed with this would remain a matter for the Commission, consistent with the functions and purpose of these bodies.

1.2 We consulted with stakeholders through several rounds of consultation

Stakeholder observations throughout all stages of this rule change process have helped shape the Commission's final determination.

The role of operational procurement

AEMO and ENA supported our analysis that there are unlikely to be benefits of implementing a real-time inertia market in the short- to medium-term aligning with the draft position to not implement an inertia market at this stage.[8] AEMO also confirmed our estimate of $30 million net present value of costs to implement and operate an additional inertia market over 10-years to be reasonable.[9]

AEC and CEC members however, opposed the draft decision not to implement a new operational procurement mechanism for inertia, raising concerns about key assumptions in HoustonKemp's modelling, the existing inertia procurement framework, the role of TNSPs in procuring system security services, and the Commission's view of future inertia supply and demand.[10]

HoustonKemp's modelling, which we commissioned for our directions paper, has helped inform our analysis for our draft and final determinations. This analysis identified that the estimated short-term benefits of operational procurement of additional inertia were modest and uncertain under current system conditions, and highly sensitive to assumptions, particularly around the timing of how the obligations for system strength are met and the profile of FCAS costs.[11] The Commission has considered stakeholder feedback on this modelling and, even taking this into account, considers the conclusions still valid (see section 3.2.3 for more detail).

The Reliability Panel's role in monitoring inertia conditions

Several stakeholders support the Reliability Panel being tasked to monitor inertia-related metrics in its RASR and inform the Commission if the overall benefits of operational procurement increase.[12] AEC, ENGIE, CS Energy and Snowy Hydro considered that clear, quantified metrics that would trigger the development of an inertia market are required.[13] EnergyAustralia also supported this sentiment but stated that the Reliability Panel should be provided with more prescriptive guidance on how to analyse the inertia-related metrics.[14] The Commission does not consider that

8 Submissions to the draft determination: AEMO, p 1; ENA, p 1.

9 AEMO, submission to the draft determination, p 3.

10 Submissions to the draft determination: Australian Energy Council, AGL, CEC and AEC, CS Energy, Delta, EnergyAustralia, ENGIE, Origin, Snowy Hydro, Stanwell, Tesla.

11 HoustonKemp, [Evaluating market designs for inertia services]().

12 Submissions to the draft determination: AEMO, p 4; ENA, pp 1-2; EnergyAustralia, pp 4-5; Origin, p 3; TasNetworks, p 1.

13 Submissions to the draft determination: AEC, p 6; ENGIE, p 3; CS Energy, p 5; Snowy Hydro, p 5.

14 EnergyAustralia, pp 4-5.

specific 'triggers' should be prescribed for reconsidering operational procurement of inertia because it is not possible to distil all relevant factors into a set of triggers that definitively guarantees there will be benefits for consumers (see section 3.8.1 for more detail).

System security governance and improvements to frameworks

Select stakeholders also suggested various improvements to broader system security frameworks. Many of these concerns centred around the need to address the limited incentive for AEMO to use the transitional services framework to progress Type 2 contracts.[15] Some stakeholders considered that there is a need for a clear governance framework to facilitate technical developments, and others recommended that additional obligations should be placed on AEMO to utilise this framework. The Commission considers that a new governance framework would likely duplicate existing security frameworks and the existing role of the Reliability Panel (see section 4.4), and that obligations on AEMO for Type 2 contracts would be inefficient (see section 4.2.1 for more discussion on these points).

Several stakeholders also considered that there should be stricter requirements on the development and content of AEMO's Transition Plan for System Security,[16] with CS Energy stating that the TPSS should mirror the ISP, with the Reliability Panel having more rigorous oversight of this process, to ensure it upholds transparency and accountability of AEMO.[17]

The Commission has carefully considered all stakeholder feedback received through this consultation process in developing its final determination. Chapter 4 provides further detail on stakeholder views received and the Commission's response, which outlines why we consider the existing rules and obligations relating to the TPSS and Type 2 contracts are suitable.

1.3 Our final determination will support ongoing implementation of security reforms introduced through the Improving security frameworks rule and other processes

The AEMC improved the inertia procurement framework (amongst other elements) through the *Improving security frameworks for the energy transition* Rule 2024. This rule made changes to the framework to require AEMO to:

- determine a system-wide inertia level for interconnected operation
- determine inertia sub-network allocations for each mainland NEM region, promoting balanced and distributed procurement across NEM regions
- publish an inertia network service specification, which sets out the minimum requirements for both synchronous and asynchronous plant to provide inertia, and removes restrictions on using synthetic inertia for minimum inertia requirements

The rule also:

- aligned elements of the TNSP inertia procurement framework with the system strength framework
- allowed the use of the NSCAS framework to procure inertia, if it is required to meet an inertia gap within the next three years
- introduced a new enablement procedure, which will empower AEMO to enable system security contracts to meet gaps in minimum security requirements at least cost.

15 Submissions to the draft determination: AEC, pp 7-8; CS Energy, p 6; Iberdrola, p 1; CEC, pp 3-4; Energy Australia, p 5.

16 Energy Australia, pp 2-5; Iberdrola, p 1; CEC, p 4.

17 CS Energy, p 2.

To implement these reforms, AEMO has already updated its Inertia Requirements Methodology in November 2024,[18] and published its latest annual Inertia Report in December.[19] However, implementation of this rule is still ongoing, with most of the recent changes having commenced on 1 December 2024[20] and the remaining aspects of the new framework to commence on 2 December 2025. From 2 December 2025, AEMO will also determine real-time inertia requirements as part of its Security Enablement Procedures.[21]

As a result of the ISF rule, the Commission also introduced a requirement for AEMO to prepare an annual Transition Plan for System Security (TPSS) (see section 4.1 for more detail). The Commission considers that increasing the visibility of AEMO's existing technical work programs is the most appropriate and proportionate way to address the concerns raised in response to the Directions Paper and the Draft Determination, [22] rather than introducing new regulatory obligations at this stage. We also note that in response to the draft determination, AEMO confirmed that it is progressing a substantial body of work to address stakeholder concerns around the lack of transparency, with a more fulsome discussion of inertia to be covered in the 2025 TPSS, as well as broader industry consultation.

Through the ISF rule the Commission also introduced the transitional services framework so that AEMO can procure Type 1 and Type 2 contracts (see section 4.2 for more detail). These contracts aim to reduce current and future reliance on market interventions or directions to manage power system security issues. In response to the Draft determination AEC, CEC, CS Energy, EnergyAustralia and Iberdrola raised concerns around the lack of incentive or obligations on AEMO to use the Transitional services framework to progress Type 2 contracts.[23] The Commission recognises these concerns. The Commission notes that AEMO is undergoing work which addresses these issues (see section 4.2.1 for more detail), and intends to release further information about type 2 contracts soon. As such, the Commission does not propose to introduce more obligations on AEMO at this time given the associated regulatory burden and potential unintended consequences.

In this context, the Commission considers that initiating the operational procurement of inertia without letting the remaining aspects of the recent ISF reforms come into effect would likely increase system security costs. Premature reforms may result in consumers incurring costs for tools that may not be used, and would leave industry with an unclear direction as to how to procure and provide inertia, risk system security, and undermine regulatory certainty.

18 See AEMO's updated Inertia Requirements Methodology, which includes the inertia network service specification at Appendix A

19 See AEMO's 2024 Inertia Report

20 For more information, see section 4.4.1 of the Commissions directions paper.

21 See AEMO's Security Enablement Procedures, and section 3.4.1 of the Commission's draft determination for more information.

22 See AEMC, draft determination, section 4.2.2, pp 37-39 for more detail.

23 AEC, pp 7-8, CEC, p 4; CS Energy, p 6; EnergyAustralia, p 5, Iberdrola, p 4.

2 The final determination will contribute to the energy objectives

When deciding whether to make a rule, the Commission is required to act in the long-term interests of energy users by considering whether the rule will or is likely to contribute to the achievement of the NEO.

The Commission is satisfied that the final determination to make no rule will contribute to the achievement of the NEO. By avoiding the implementation of a market that is not yet likely to deliver net benefits, the decision supports a more informed and cost-effective implementation pathway in the future if operational procurement becomes beneficial. The Commission considers that this decision will also promote efficient investment by preserving optionality through monitoring system conditions, allowing technical work to progress further and reconsidering operational procurement if and when it becomes beneficial.

This chapter provides further detail on:

- the matters the Commission must take into account when making a rule, or a more preferable rule (see section 2.1 and section 2.2)
- how we have applied the legal framework when making our final determination (see section 2.3).

2.1 The Commission must act in the long-term interests of energy consumers

The Commission can only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the relevant energy objectives.[24]

For this rule change, the relevant energy objective is the NEO:

The NEO is:[25]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[26]

24 Section 88(1) of the NEL.

25 Section 7 of the NEL.

26 Section 32A(5) of the NEL.

2.2 We must also take these factors into account

2.2.1 We have considered whether to make a more preferable rule

The Commission may make a rule that is different, including materially different, to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO.[27] For this rule change, the Commission has decided to make no rule. The reasons are set out in section 2.3 below.

2.3 How we have applied the legal framework to our decision

The Commission must consider how to assess the risk that current frameworks may not continue to support the efficient and cost-effective procurement of inertia as system conditions evolve against the legal framework.

We identified the following criteria to assess whether the proposed rule change, no change to the rules (business-as-usual), or other viable, rule-based options are likely to better contribute to achieving the NEO:

1. **Safety, security and reliability** - The Commission considered whether each option would support the continued secure operation of the power system, including maintaining system security under declining synchronous inertia conditions. The assessment included the extent to which inertia needs are currently being met and whether alternative approaches would materially improve system security outcomes.
2. **Emissions reduction** - The Commission examined whether each option would contribute to emissions reduction by supporting the integration of emerging low-emission technologies, consistent with broader emissions reduction objectives.
3. **Principles of market efficiency** - This criterion was used to assess whether each option would promote efficient investment and operational decision-making. The Commission considered each option's implications for allocative efficiency, incentives, and competitive neutrality in supporting least-cost outcomes over time.
4. **Innovation and flexibility** - The Commission assessed whether each option would maintain flexibility to respond to future system needs and support innovation in the supply of inertia, including enabling new technologies such as grid-forming inverters
5. **Implementation considerations** - The Commission evaluated whether each option would be proportionate and timely, taking into account implementation complexity, interactions with other reforms, and the costs of change relative to likely benefits.

These assessment criteria reflect the key potential impacts, costs and benefits of the rule change request, for impacts within the scope of the NEO. Our reasons for choosing these criteria are set out in section 4.2 of our consultation paper and section 3.2 of our directions paper.[28]

The Commission has evaluated the impacts of the various policy options against the assessment criteria, taking into account our own quantitative and qualitative analysis, HoustonKemp's quantitative analysis, and all stakeholder feedback and submissions over the course of this rule change.

27 Section 91A of the NEL.

28 In our consultation paper, the five criteria listed were: power system security, principles of market efficiency, costs and complexity, timing and uncertainty, and innovation and flexibility. However, we revised these assessment criteria in our directions paper to include emissions reduction, as well as renaming some criteria (for example, 'costs and complexity' changed to 'implementation considerations'; 'power system security' changed to 'safety, security and reliability'.

The rest of this section explains why the Commission considers that not making a rule best promotes the long-term interest of consumers when compared to other options and assessed against the criteria set out above.

2.3.1 Our final determination is to make no rule

The Commission has decided to make no rule. The final determination is largely consistent with the draft determination, in that we consider not making a rule best contributes to the achievement of the NEO. This is because:

- we do not consider that operational procurement of minimum inertia is currently suitable (see section 3.1)
- the benefits of procuring additional inertia are small and are outweighed by the costs of implementing a new operational procurement mechanism (see section 3.2)
- expected inertia supply greatly exceeds minimum requirements over the next ten years, due to the obligations to meet system strength requirements (see section 3.3 and section 3.4)
- minimum inertia demand is not likely to increase in the future due to larger credible contingency sizes, because these would present unacceptable engineering risks and would therefore be avoided in the planning process (see section 3.5)
- AEMO has the operational tools to meet inertia gaps that may arise due to capacity being offline, without resorting to market interventions or directions (see section 3.6)
- we do not miss out on benefits by waiting, because technical work and system security reforms are still progressing (see section 3.7)
- the Reliability Panel will monitor system conditions that would warrant the reconsideration of a real-time market for inertia and inform the Commission if conditions evolve in a way that increase the potential benefits of an operational procurement mechanism for inertia (see section 3.8)
- further obligations on AEMO are not necessary at the current time due to the reasons set out below

We have considered a wide range of stakeholder feedback and suggestions provided in all stages of consultation. We have maintained our encouragements to improve opportunities in existing frameworks. While stakeholders asked us to strengthen governance over AEMO's processes,[29] we do not consider that introducing new rules or obligations upon AEMO relating to its Transition Plan for System Security or use of the transitional services framework is appropriate at this time because:

- stakeholder concerns can be addressed through improved transparency on AEMO's technical priorities and security planning, which we have confirmed with AEMO is a key focus for them (see section 4.1)
- the transitional services framework affords AEMO the ability to manage system security with a degree of flexibility. Enforcing fixed obligations on AEMO and/or further amendments to the RIT-T process or new procurement obligations on TNSPs at the current time is likely to be inefficient and may lead to increased consumer costs, or is out of scope to the rule change request (see section 4.2 and section 4.3)

29 Submissions to the draft determination: Australian Energy Council, pp 7-9; CS Energy, p 6; Delta, p 2; CEC and AEC, pp 3-4; Energy Australia, p 5; Snowy Hydro, pp 4-5.

- introducing a new governance framework to oversee AEMO's technical work program is not appropriate because it would duplicate existing security frameworks and the existing role of the Reliability Panel, which already has several security-related functions. (see section 4.4).

For the reasons set out below, the Commission considers that the decision to make no rule will better contribute to the NEO.

2.3.2 The final determination supports the secure and reliable operation of the power system

The Commission considers that the final determination will support secure and reliable system operation by retaining the long-term procurement framework and enabling targeted improvements to its application. While the Commission recognises that operational procurement of inertia may have a role in the future, it does not consider that there would be net benefits in the near term under current and expected system conditions.

The secure operation of the power system continues to be supported through the minimum inertia requirements established in the NER, informed by AEMO's projection of inertia requirements (in accordance with the Frequency Operating Standard) and TNSPs' obligations to ensure sufficient inertia is available. The Commission found that foreseeable inertia needs are expected to be met in the short to medium term under the enhanced procurement framework introduced through the ISF rule change, which is still being implemented (see section 3.3 and section 3.4).

The Commission also considered whether an operational procurement mechanism for inertia would materially improve system security outcomes. As discussed in section 3.2, there are no net benefits in relation to an operational procurement mechanism for inertia under current assumptions. HoustonKemp's modelling found that while operational procurement of additional inertia could reduce system costs under certain conditions, the magnitude of benefits was modest and highly sensitive to input assumptions.[30] Some stakeholders, expressed broad support for the concept of operational procurement for inertia but noted that the value of such a mechanism would depend on system conditions and may not be justified in the near term.[31] Other stakeholders considered that we underestimated the likelihood that future benefits will increase, or that we misrepresented the marginal value and costs of an inertia market.[32]

However, the Commission is satisfied with our analysis which suggests that operational risks can continue to be managed under current frameworks, particularly as technical tools and system capabilities continue to improve. This is supported by the substantive amount of planned and ongoing work that AEMO is progressing to improve its understanding on maintaining power system security throughout the transition (see chapter 4 for more information).

The Commission intends to task the Reliability Panel with monitoring system conditions that, if they change in ways we do not currently expect, could indicate that operational procurement may be more likely to deliver net benefits than we currently estimate (see section 3.8). The Panel would monitor and report on these metrics, but it would not determine whether implementation is warranted. Any decision on operational procurement would remain a matter for the Commission, consistent with our role and function.

As outlined in Chapter 4, the Commission has identified opportunities to strengthen procurement transparency and improve how existing frameworks are applied. These measures, along with AEMO's technical work programs related to inertia (see section 4.1.1), would further support secure operation without requiring the introduction of an operational procurement mechanism at

30 AEMC, directions paper - Efficient Provision of Inertia.

31 Submissions to the draft determination: AEMO, p 1; ENA, p 1; EnergyAustralia, p 1.

32 Submissions to the draft determination: Energy Australia, p4; Delta, p 2; AEC, p 5; CS Energy, p 3, Snowy Hydro, p 2.

this stage. The Commission considers that this approach would maintain a proportionate and flexible pathway for reform. It would avoid introducing a new operational procurement mechanism that does not yet have net benefits, given the modest and uncertain short-term gains and the material complexity of implementation.

2.3.3 The final determination recognises that existing arrangements encourage emissions reduction by supporting integration of emerging low-emissions technologies

The Commission considers that existing frameworks, including the updated system strength and inertia procurement arrangements, sufficiently support emissions reduction objectives in providing inertia. Recent reforms have enabled TNSPs to procure synthetic inertia, and AEMO's updated Inertia Requirements Methodology now incorporates the contribution of fast frequency response in determining minimum inertia needs.[33]

Given these developments, the Commission does not consider that implementing operational procurement for inertia at this time would result in material emissions benefits. While the current framework allows for the use of low-emission technologies, including synthetic inertia and grid forming inverters, confidence in these technologies is still evolving. Currently, AEMO's and TNSP's positions is that to meet minimum levels of system strength, only synchronous units can be used. TNSP's are actively exploring using these technologies to meet obligations above minimum levels, however. Further operational experience and demonstration will likely be needed before these technologies can be rolled out more broadly. Importantly, there are no regulatory impediments to their participation, and we expect to see increased uptake of these technologies as we continue to learn about how they can best contribute.

As the incremental emissions benefit from displacing contingency FCAS or enabling higher penetrations of inverter-based resources (IBRs) is expected to be limited, operational procurement of additional inertia is unlikely to improve emissions outcomes in the near term. This is due to the projected availability of inertia from assets already committed under existing frameworks and the relatively low emissions intensity of contingency FCAS providers under current system conditions.

As outlined in Chapters 3 and 4 of the draft determination, the Commission assessed whether introducing operational procurement of inertia at this time would better support the development and participation of technologies capable of providing synthetic or non-synchronous inertia. Several stakeholders submitted that operational procurement of inertia could, over time, provide stronger signals for investment and help unlock the value of grid-forming inverters and battery-based solutions.[34]

The Commission agrees that operational procurement of inertia has merit and could play an important role in supporting emissions reduction in the long term. This is because a well-designed market-based mechanism may allow greater volumes of IBR to operate securely by reducing the need for constraining synchronous units online to maintain system security. Over time, this could reduce reliance on higher-emission generators and increase the share of zero-emission generation in dispatch.

However, the Commission found that these emissions benefits are only likely to become material if system conditions change substantially, such as through higher minimum inertia requirements, earlier retirement than expected of synchronous generators, or a material increase in RoCoF-related constraints. Under current conditions, implementing operational procurement of inertia is

33 AEMO, Inertia Requirements Methodology (1 December 2024).

34 Submissions to the directions paper: Akaysha Energy, pp 5-6; EnergyAustralia, p 4; Tesla, p 5; Iberdrola p 2 and Snowy Hydro, p 4; Submissions to the draft determination: Delta, p 1, AGL, p 2.

not expected to meaningfully shift the generation mix or reduce emissions, given that inertia needs can be met through work underway to meet system strength obligations, and contingency FCAS providers are already relatively low emissions.

In the meantime, existing mechanisms, including long-term contracting by TNSPs and AEMO's ability to enter into Type 2 contracts to trial new applications of inertia-providing technologies, offer a credible pathway for supporting innovation and learning in lower-emissions sources of system security.

The Commission also considered stakeholder concerns that current procurement practices may favour established technologies and limit contestability. While acknowledging these concerns, we recognise that they relate to broader issues in the regulatory framework that those we are considering here (such as the network regulation framework and incentives for capital vs operating expenditure). The Commission considers there are opportunities to improve the application of existing frameworks that can help reduce barriers to participation by low-emission technologies, even in the absence of an operational procurement mechanism.

Overall, the Commission considers that retaining the current framework, while enhancing its application and supporting further technical development, will provide a proportionate and flexible pathway for enabling emissions reduction through innovation in inertia provision.

2.3.4 The final determination promotes market efficiency

The Commission considers that the final determination promotes market efficiency by maintaining a framework that enables efficient procurement decisions, while avoiding the costs and risks of implementing an operational procurement mechanism for inertia that does not have net benefits under current and expected system conditions.

Operational procurement of inertia has the potential to improve allocative and dynamic efficiency by introducing price signals, supporting co-optimisation, and broadening participation. The Commission acknowledges that these benefits may increase in the future, if system conditions change. However, as outlined in Chapter 3, the Commission found that the likely efficiency gains in the short to medium term are limited and uncertain, and do not outweigh the implementation costs at this stage.

The HoustonKemp modelling commissioned by the Commission found that while operational procurement could reduce system costs under certain conditions, the scale of potential savings is modest and highly sensitive to assumptions. Several stakeholders[35] questioned aspects of the modelling assumptions about the cost of inertia provision from different sources, with some raising that the cost of an inertia market should be compared against the cost of synchronous condenser procurement and TSNP RAB increases. Others supported HoustonKemp's analysis,[36] and considered that a more cautious approach was appropriate, in order to take the recent enhancements to the long-term procurement framework through the ISF rule change into account.[37] The Commission agrees that these points are important and has taken them into account in interpreting the modelling results and assessing the case for reform. A detailed discussion of these issues is provided in Chapter 3 of the draft determination.

The Commission considers that the current framework will continue to support efficient procurement outcomes where it is applied transparently and proportionately. While it may not

35 Submissions to the draft determination: Australian Energy Council, p 5; Snowy Hydro, pp 2-3, Delta, p 2.

36 Submissions to the draft determination: AEMO, p 1; ENA, p 1; TasNetworks, p 1; Transgrid.

37 Submissions to the directions paper: AEMO, pp 1-2; ENA, pp 1-2.

deliver the same level of price discovery as operational procurement, improved application of the existing frameworks, such as through clearer communication of procurement assumptions and better integration of emerging technologies can help ensure that inertia levels align with secure operating thresholds, while avoiding excessive investment that does not materially improve outcomes for consumers.

For example, a more transparent articulation of how fast frequency response (FFR) and IBRs are factored into procurement decisions can reduce the risk of TNSPs procuring more synchronous inertia than is needed or deferring efficient investment due to uncertainty. These refinements, while modest, can meaningfully improve the alignment of procurement outcomes with system needs and consumer interests. They may also support more effective stakeholder engagement and contribute to improved price transparency over time by increasing visibility into how procurement needs are determined and valued.

The Commission also notes that, based on current TNSP procurement plans, a significant portion of foreseeable inertia needs is expected to be met by solutions delivered to address system strength needs. While multiple technologies may be used to meet system strength needs, TNSPs are progressing work to meet system strength obligations, either by investing in synchronous condensers or contracting with others including grid forming inverters or synchronous generators equipped with clutches, which are likely to also provide inertia at a low incremental cost. This reduces the immediate need to establish separate operational procurement arrangements for inertia. While these plans are still evolving, the Commission considers this a relevant factor when assessing the relative efficiency of the current framework compared to operational procurement of inertia.

2.3.5 The final determination supports innovation and flexibility by preserving option value

The Commission recognises that operational procurement for inertia may have net benefits in future, but considers that preserving the current framework offers greater option value. Maintaining a flexible, low-regret approach enables the regulatory framework to adapt efficiently as technologies mature, system needs evolve, and the benefits of real-time procurement for inertia become clearer. The Commission considers that a decision not to make a rule at this time appropriately supports innovation and flexibility, as existing frameworks, including AEMO's ability to enter into Type 2 contracts, already provide a pathway for trialling new technologies in the provision of inertia. This approach also preserves the ability to implement operational procurement in the future if system conditions change.

Stakeholders, in response to the directions paper,[38] highlighted the importance of providing pathways for grid-forming inverters and other emerging technologies to demonstrate capability and build commercial readiness. While operational procurement of inertia was seen as a potential long-term enabler of innovation, stakeholders acknowledged that further technical work, operational tools and clear performance standards would be required before such a mechanism could be implemented effectively.

In response to the draft determination, AEC members considered that a revised governance framework is needed to address the limited incentive for AEMO to use the transitional services framework.[39] However, we note the recent ISF rule, which set up this framework and considered similar issues, is yet to be implemented in full, and we consider this should be implemented in full before changes are considered. AEMO has also confirmed that it is progressing work to address

38 Submissions to the directions paper: Tesla, p 2; Iberdrola, p 2; Akaysha Energy, p 4

39 Submissions to the draft determination: AEC, pp 8-9; CS Energy, p 2.

these concerns, and that consideration of inertia will be more substantive in the 2025 TPSS (see section 4.1.1 for more detail).[40]

The Commission considers that meaningful progress can still be made through continuing to refine and learn how best to use existing tools, particularly AEMO's use of Type 2 contracts to trial new applications of emerging technologies (see section 4.2), and the ongoing refinement of technical standards and modelling capabilities (see section 4.1).

As outlined in Chapters 3 and 4, the Commission found that operational procurement of inertia does not have net benefits under current assumptions, although we acknowledge this may change in future. Therefore, the final determination preserves the flexibility to implement operational procurement for inertia in the future, if and when its net benefits become more material. As discussed in section 3.8, the Commission intends to ask the Reliability Panel to monitor relevant indicators through the RASR, which many stakeholders support.[41] Some stakeholders raised that the Commission should provide prescriptive guidelines and quantitative metrics for the Reliability Panel, which would clearly define when a real-time inertia market will be beneficial.[42] However, the Commission does not consider that providing hard triggers or thresholds is appropriate, because it is not possible to distil all relevant factors into a set of specific triggers that would guarantee benefits for consumers (see section 3.8.1 for more detail).

Depending on the outcomes of the Reliability Panel's monitoring, the Commission would then consider revisiting operational procurement of inertia through a rule change if conditions warrant it. This approach supports innovation by enabling system learning and capability building while maintaining the existing inertia framework. It also maintains a flexible, low-regret pathway that can adapt to evolving technologies and market conditions.

2.3.6 The final determination takes into account implementation considerations

The Commission has considered implementation timing, technical readiness, and interactions with other reforms in reaching its final determination not to introduce an operational procurement mechanism for inertia at this stage. Given that there are no net benefits, implementing a new mechanism may complicate procurement coordination and introduce additional administrative burden, without delivering commensurate benefits.

As stated in the draft determination, valuable learning can be undertaken in parallel with the new ISF reforms playing out, through continuing to undertake technical work to support continuous improvement under the existing framework. This work will support readiness for the implementation of operational procurement (should benefits arise in the future).

The Commission also considered the power system's technical readiness to support operational procurement. As discussed in sections 3.2 and 4.2 of the directions paper, further knowledge and learning are needed in areas such as real-time inertia measurement, locational requirements, and dispatch integration into the NEM. AEMO and other stakeholders noted that progressing these technical capabilities would be a necessary precondition to implementing operational procurement effectively. Continuing to focus on improvements in these areas is a 'low regrets' system learning exercise that can inform future procurement reforms if and when they are pursued.

40 AEMO, submission to the draft determination, sections 3.1-3.2, p 3.

41 Submissions to the draft determination: AEMO, p 4; ENA, pp 1-2; TasNetworks, p 1; Origin, p 3.

42 Submissions to the draft determination: Australian Energy Council, p 6; EnergyAustralia, pp 4-5; ENGIE, p 3

Therefore, the decision not to implement operational procurement of inertia at this time does not mean that consumers miss out on near term benefits, as technical work that would facilitate implementation is already underway.

Consequently, the Commission considers that the final determination allows time for these related reforms and technical work programs to progress, and continually improve, while preserving flexibility to revisit operational procurement for inertia if conditions warrant it. This approach supports a more informed, coordinated and cost-effective implementation pathway in the future.

3 The Commission considers that there are no net benefits from an inertia market at this time

Box 1: Key points in this chapter

We do not consider that operational procurement of minimum inertia is currently suitable

- Consistent with our analysis in our directions paper and draft determination, we consider that minimum inertia does not currently exhibit the economic characteristics to support operational, real-time market-based procurement.
- Due to the criticality of minimum inertia for the secure operation of the power system, minimum inertia has a high cost of undersupply. It also requires a large amount of capital expenditure to enter the market and so requires a high degree of investment certainty.
- We consider that the high costs of undersupply combined with investment uncertainty makes minimum inertia unsuitable for operational procurement at this time.

The benefits of procuring additional inertia are outweighed by the costs

- Although additional inertia can result in efficiency gains and benefits for consumers, our modelling suggests that, under the most likely scenarios, these benefits would be very small (approximately $4 million in net present value terms, over the next eight years).
- The costs of establishing and operating a real-time inertia market were estimated at $30 million in net present value terms. This means that a real-time inertia market would not result in any net benefits for consumers at this time.

Expected inertia supply greatly exceeds minimum requirements over the foreseeable horizon

- Based on a conservative estimate of how system strength requirements would be met, as outlined by each TNSP's PACR, there is likely to be a significant excess of supply against minimum inertia requirements.

On the supply side, meeting system strength obligations is likely to deliver substantial inertia

- In meeting their system strength obligations, TNSPs must ensure that there is a sufficient amount of protection-quality fault current at each system strength node in their network.
- Currently, synchronous sources are the only credible options to supply fault current for minimum levels. TNSPs and AEMO have recognised that this may change in the future with more knowledge and experience. Other sources can be used to meet efficient levels above the minimum.
- Given this current engineering understanding, TNSP's are meeting minimum levels for system strength by procuring or contracting for synchronous condensers. These are expected to be installed with flywheels, as this assists in meeting a TNSP's inertia requirements simultaneously. This will provide substantial inertia, contributing to the excess supply that we currently forecast.

Credible contingencies are not likely to drive increases in minimum inertia requirements

- Although the size of non-credible contingency events may increase in the future, the size of **credible** contingency events is not likely to increase, because this would impose many other significant adverse effects on system security. Instead, control schemes are likely to be used to mitigate these risks. Procuring inertia would not resolve these adverse effects.

AEMO has the tools to meet any gaps due to capacity being offline

- AEMO will be able to manage any system security gaps that may arise at least cost to consumers through its new enablement process for system security contracts.
- Market participants and future connecting plant have the opportunity to be compensated for their security service provision through contracts with TNSPs to meet their ongoing inertia and system strength obligations. TNSPs are already procuring these options, following the conclusion of their RIT-T processes.

We do not miss out on benefits by waiting because technical work and system security reforms are still progressing

- Little to no time would be lost if work on a real-time inertia market were to commence now, versus waiting for the required technical work above that is already underway to progress further.
- We preserve the option value of waiting to determine the best enduring approach for providing inertia, so that we can better incorporate new power system knowledge technologies to make optimal market design choices.

The Commission will task the Reliability Panel to monitor system conditions that would warrant the reconsideration of a real-time market for inertia

- The Commission will amend the Terms of Reference of the Reliability and Security Report so that the Reliability Panel must report on inertia-related metrics and comment on their evolution and expectations.
- If the Panel considers that the Commission should reconsider operational procurement, then it may choose to submit a rule change request.

The Commission supports using real-time markets for system security services, where technically feasible and economically beneficial

- The right procurement approach for a security service should be tailored to the technical characteristics, function and costs of providing the service.

The Commission has concluded that, at this time, a new operational procurement mechanism for inertia would not have any net benefits to consumers. The Commission has conducted cost-benefit analyses, assessed the interactions between existing system security frameworks, and has considered a wide range of stakeholder feedback in making its decision.

3.1 We do not consider that operational procurement of minimum inertia is currently suitable

To analyse whether we should introduce operational procurement of inertia, we developed a two-step test:

1. In the first step, we, together with HoustonKemp Economists, analysed the economic characteristics of inertia. This focused on each of the following:
   - the nature of the service
   - the need for investment certainty
   - opportunities for efficiency gains
   - economic consequences of supply and demand imbalances
   - competitive factors.

2. In the second step, if the economic characteristics were found to be suitable for operational procurement, we identified and quantified the potential benefits of operational procurement.

We identified that different uses of inertia have significantly different economic characteristics, which we categorised into two types of inertia:

- **Minimum inertia,** which is the amount of inertia required for the secure operation of the power system. It must be appropriately distributed across the NEM. If the power system does not meet this minimum inertia demand (while considering the distribution of inertia), then the system would be operating in an insecure state.
- **Additional inertia** is any excess to the amount of inertia required for the secure operation of the power system. Additional inertia can help reduce other system requirements, such as the amount of primary frequency response, and can allow AEMO to dispatch a lower-cost generation.

3.1.1 Minimum inertia is not currently suitable for operational procurement

We found that minimum inertia is currently unsuitable for operational procurement. In our analysis of the economic characteristics of inertia, we found:

- Minimum inertia can be well-defined which is necessary to allow operational procurement
- For secure operation, the power system requires consistent availability of inertia. Currently, this requires investments in synchronous condensers or generators, converting existing synchronous generators to synchronous condensers, or ensuring that sufficient headroom is reserved from grid-forming batteries. At present, with TNSPs expected to undertake investments or enter into contracts to meet their system strength requirements, it is not clear that there is sufficient certainty to support investment. There are high risks to investors that investment in inertia would not be bankable.
- There may be opportunities for efficiency gains in the provision of minimum inertia. However, this is only likely if system strength is not provided by assets such as synchronous condensers that also produce inertia (see section 3.4).
- There are very high potential costs of an undersupply of minimum inertia. Insecure operation of the electricity system can lead to the high costs of load shedding or even large-scale blackouts. It is difficult to estimate the economic costs of large-scale blackouts, however one estimate put the cost of the 2016 South Australia-wide blackout at $367 million to businesses over its 8-hour duration.[43] Wider and longer duration outages could impose far greater costs on Australia.
- New technologies and innovations, including battery energy storage systems, adding clutches to gas turbines, improved real time measurement methods, and sufficient supply may, in time, create sufficient liquidity and competitive pressure for a workably competitive minimum inertia market. We note that these options are already being considered by TNSPs following the conclusion of their system strength RIT-Ts.

We consider that the very high potential costs of an undersupply combined with the need for investment uncertainty for minimum inertia sources makes minimum inertia unsuitable for operational procurement at this time.

Many stakeholder submissions to our directions paper, including those who supported operational procurement of additional inertia, also supported continuing to use long-term contracts for

43 Business SA, Blackout survey results.

minimum inertia in the near term.[44] Stakeholders generally supported the Commission's view that the long-term procurement framework is better suited to securing minimum system needs, given the high cost of under-procurement and limited opportunity for dynamic optimisation. In submissions to the draft determination, only some stakeholders supported the continued use of contracted procurement for minimum inertia.[45]

Origin's submission to the draft determination noted that FCAS is procured operationally, which is also essential for secure operation of the electricity system.[46] We consider that FCAS likely required less capital investment, as it was highly substitutable with wholesale electricity, scalable to system demand (i.e. certain assets can only provide 100% of its inertia) and it did not face the same expectation of future supply being affected by other investments needed for system security. In the future, with greater certainty that inertia supply will not be materially affected by other system security needs, there may be a stronger case for operational procurement of minimum inertia in the future.

More detailed analysis on minimum inertia is provided in section 7.1 of our directions paper.

3.2 The benefits of procuring additional inertia are outweighed by the costs

3.2.1 Additional inertia has characteristics that would allow operational procurement

Additional inertia has most of the economic characteristics that support operational procurement:

- Additional inertia can be well-defined which is necessary to allow operational procurement.
- Additional inertia does not need consistent availability, it is only useful when it is available at a lower cost than the services it is substituting for. Therefore, it is suitable for 'value stacking' and effectively has low marginal costs of investment.
- There are low costs of an undersupply of additional inertia, as it simply results in purchasing more FCAS or paying for the dispatch of a slightly more expensive generation portfolio.
- Competitive pressure and liquidity is likely to emerge given it is likely a smaller market with fewer technical restrictions on participation.
- Entry is likely low cost as most participants would use inertia for value stacking on top of wholesale market and frequency services market revenue.

As such, we found that additional inertia has the appropriate economic characteristics. Therefore, we proceeded to test the likely costs and benefits of operational procurement of additional inertia.

3.2.2 The benefits of additional inertia are currently very low and are not expected to increase

Together with HoustonKemp, in our analysis for our directions paper we identified that additional inertia can:

1. Reduce system costs of frequency management by using additional inertia to reduce the required quantity of 1-second FCAS.
2. Reduce system costs of wholesale energy by using additional inertia to relieve rate of change of frequency constraints on renewables output in Tasmania and South Australia - allowing lower-cost energy to be dispatched.

44 Submissions to the directions paper: Iberdrola, p 3, Akaysha Energy, p 2, TasNetworks, p 1, SMA, p 1, AEMO, p 1, ENA, p 1 and Tesla, p 5.

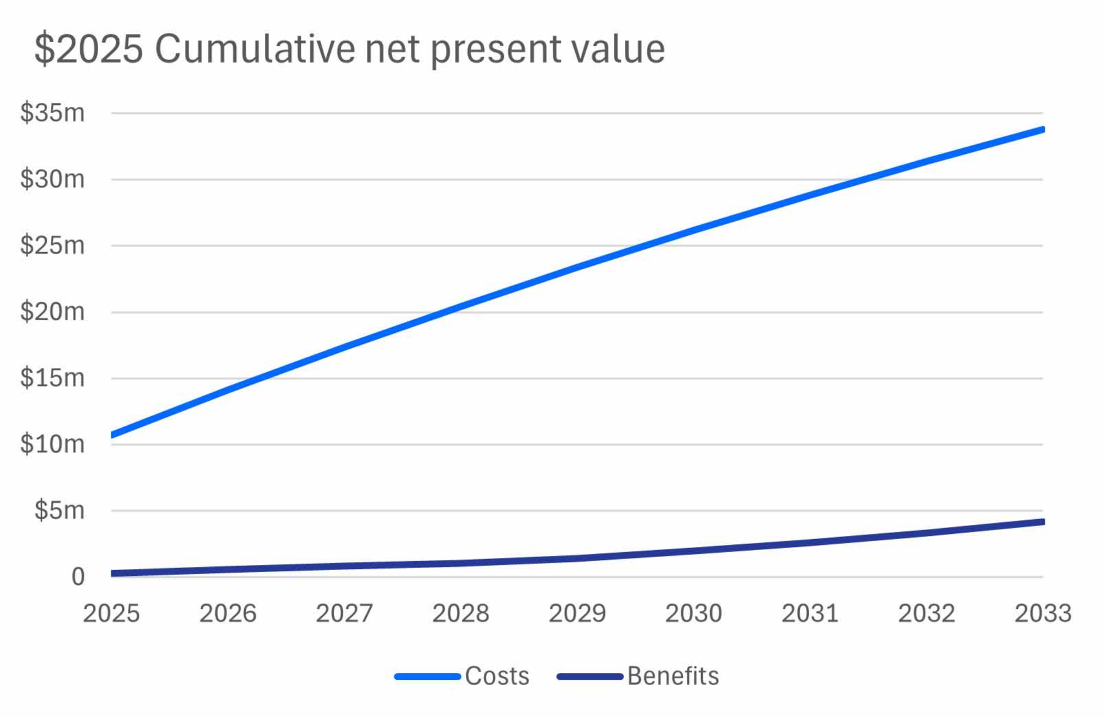
45 Submissions to the draft determination: AEMO, pp 1-2; ENA, p 1; Reactive Technologies, p 1; Transgrid, p 1; TasNetworks, p 1.

46 Origin, submission to the draft determination, p 2.

3. Reduce system costs of wholesale energy by enabling greater output from the largest generating units in the NEM - in other words, allow increased contingency sizes.

We found, in our modelling horizon (until 2033), that these benefits are insufficient to cover the expected costs of establishing and operating an inertia market. We estimated costs of about $30 million (with a lower bound estimate of $19 million) and benefits of about $4 million in net present value terms - see Figure 3.1 and Table 3.1.

Figure 3.1: AEMC analysis of likely costs and benefits from operationally procuring inertia



Source: AEMC

Table 3.1: Types of benefits from operationally procuring additional inertia

Benefit source/cost	Most likely scenario description	Benefits over modelled horizon
Substitution of inertia for fast frequency response	• We have used a scenario based on FCAS prices remaining flat or falling. This is the trend most aligned with Intelligent Energy System's forecast of inertia prices provided for the Integrating Price Responsive Resources rule change.[1] It is also consistent with observed 1-second contingency FCAS prices since market commencement - see Figure 3.2. • We have used HoustonKemp's average inertia cost of $0.44/MWs,	• Substitution of inertia for fast frequency response is the largest source of benefits in our modelling. We estimated benefits increasing from $0 per year in 2026 to just over $1 million per year by 2033. Over the modelling horizon substituting inertia for fast frequency response had a net present value of $2.3 million. • We estimate that under the most likely scenario, the benefits of substituting inertia for fast

Benefit source/cost	Most likely scenario description	Benefits over modelled horizon
	based on the estimated cost of synthetic inertia from inverter based resources in both 2024 and 2030.[2] • We assigned 5% of the capital cost of inverter-based resources to inertia (the lowest modelled), reflecting feedback from Tesla that existing assets would have no fixed cost and future assets would not need to reserve capacity.[3]	frequency response would need to increase at an average of just above 17% per year for the benefits in 2033 to exceed the costs over a 30-year period.
Relieving the South Australian RoCoF constraint	We included the benefits of relieving the South Australian RoCoF constraint until the scheduled completion of Project Energy Connect in 2027.[4]	We estimated benefits of around $50,000 per year in 2025 to 2027. Over the modelling horizon the benefits of relieving the South Australian RoCoF constraint had a net present value of around $145,000.
Relieving the Tasmanian RoCoF constraint	We included the benefits from relieving the Tasmanian RoCoF constraint indefinitely.[4]	We estimated benefits of around $20,000 per year. Over the modelling horizon the benefits of relieving the Tasmanian RoCoF constraint had a net present value of around $135,000.
Enabling larger contingencies	We assumed that AEMO could enable larger contingency sizes in 0.3% of intervals than currently,[5] noting that today AEMO does not co-optimise contingency size with inertia. Additionally, we reduced the benefits by two-thirds in response to AEMO's submission to the directions paper.[6]	Enabling larger contingencies is the second-largest source of benefits in our modelling. We estimated benefits of around $225,000 per year. Over the modelling horizon enabling larger contingencies had a net present value of $1.6 million.
Avoiding inertia directions	We understand all historic directions have been for system strength services. Therefore, we did not include any avoided directions benefits.	Not applicable.
Implementation and ongoing costs	We used the midpoint of HoustonKemp's estimated costs - an upfront cost of $7.5 million to develop the market and ongoing costs of $1.5 million per year for AEMO, and $300,000 per year for each of the estimated 7 or 8 participants.[7]	Over the modelling horizon we found the ongoing costs for AEMO had a net present value of $10.6 million, and the ongoing costs for participants of $16.0 million. This is additional to the upfront cost of $7.5 million.

Source: [1] Intelligent Energy Systems, *Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM (ERC0352)*, Final Report, 24 June 2024, p 61; [2] HoustonKemp, *Evaluating market designs for inertia services*, December 2024, p 60 ; [3] Submission to the directions paper Tesla, pp 3-4; [4] AEMC analysis of NEM data; [5] HoustonKemp, *Evaluating market designs for inertia services*, December 2024, pp 34-35, 40-41, based on analysis of how frequently the largest generators are constrained today; Submission to the directions paper AEMO, p 2; [7]HoustonKemp, *Evaluating market designs for inertia services*, December 2024, pp 42-44.

Figure 3.2: Daily average Very Fast contingency FCAS prices (October 2023 to April 2025)

Source: AEMO, Technical Review of the NEM Frequency Control Landscape, p 31.
Note: R1 = Raise 1-second market, L1 = Lower 1-second market

To generate higher benefits, we would need to see:

- An increase in the market price for 1-second FCAS and a separation between the additional inertia and 1-second FCAS prices. We expect this could only occur if the technologies providing inertia are unable to provide 1-second FCAS.
- AEMO updating NEMDE to co-optimise inertia and wholesale generation, allowing additional inertia to enable larger credible contingencies more regularly.[47]

At present, we are typically seeing very low 1-second FCAS prices (see Figure 3.4) and excess inertia above the minimum inertia requirement. This would likely lead to a market that clears at a zero price. We consider that this would not send a strong investment signal.

3.2.3 Stakeholder feedback to our cost-benefit analysis was mixed

We received a wide mix of feedback to our draft determination analysis of the likely costs and benefits of operational procurement of additional inertia.

AEMO, Energy Networks Australia and TasNetworks were supportive of the findings. They generally agreed that there are no net benefits in the modelling horizon.[48] AEMO confirmed that our estimate of $30 million net present value of costs to implement and operate an additional inertia market over 10-years was reasonable.[49]

Electricity generators that made submissions to our draft determination did not support our findings. We heard two main concerns raised by generators in submissions.

The Australian Energy Council and Snowy Hydro raised concerns that our draft determination implied that there are no costs to provide inertia. Furthermore, they interpreted our analysis as

47 Currently, during normal operation, AEMO does not co-optimise the size of the largest contingency together with FCAS procurement volumes and the wholesale energy market. If it did, there could be instances where procuring more inertia to cater for a larger contingency could reduce total dispatch costs. The AEMC has a received a rule change request on this topic, but has not yet initiated it. However, as explained in section 3.5, credible contingency sizes are not likely to increase beyond present-day values (approximately 750 MW) due to engineering risks.

48 Submissions to the draft determination: AEMO, p 1; ENA, p 1; TasNetworks, p 1.

49 AEMO, submission to the draft determination, p 3

meaning that we endorsed paying synchronous condensers more than synchronous generators.[50] We consider that it is sound to estimate the marginal cost of providing inertia as zero for:

- synchronous generators during intervals where they are dispatched for wholesale electricity
- synchronous condensers operating to provide system strength.

This is because in both cases, neither machine can increase (or decrease) its inertia output - even if paid to do so. Its inertia is a positive externality of providing wholesale electricity or other system security services.

Our cost estimates are not a reflection of what we believe or endorse different technologies should be paid - rather, they feed into an estimate of the overall costs to consumers from an efficiently functioning operational procurement mechanism, where prices are likely to converge to costs. Indeed, services can be equally efficiently procured with a single market price (as is the case in the FCAS and wholesale electricity markets) or with price discrimination (as allowed under contracted procurement).[51] We note that under the ISF framework, to meet their obligations, TNSPs can contract with a wide range of market participants to provide inertia services and negotiate a price for that service.

We also note that using synchronous generators as our proxy for this analysis should not be taken as endorsement for this technology over others, such as grid forming inverters. It simply represents the current best estimate of what will be procured to meet minimum system strength requirements. We are supportive of a future where grid forming inverters can be used to provide these services, but also recognise the current engineering limitations with this. We note that TNSPs are actively engaging in conversations with providers of these services as part of their process to consider how to meet their system strength obligations. The Commission continues to encourage learnings in this space.

Origin and CS Energy made submissions that they expect contingency sizes in the NEM to increase over time.[52] We did not model growing credible contingency sizes based on feedback from AEMO to the directions paper - see section 3.5 for more information.[53]

Delta argued that there is a real option value from implementing a market. Delta considers we underestimated the likelihood that future benefits will increase, citing rapidly rising contingency FCAS costs and emerging system constraints.[54] We agree that there is an option value in establishing a market now. However, based on our analysis above, we consider that this is an expensive option that is unlikely to pay off in the next 10 years.

Our final decision also has option value. The Reliability Panel will monitor the market, and should the right conditions emerge, it could choose to submit a rule change request so that the Commission can reconsider the operational procurement of inertia (see section 3.8). This avoids the costs of establishing and operating a market that is unlikely to cover its costs.

More detailed analysis of our cost-benefit analysis is provided in section 3.3 of our draft determination.[55]

50 Submissions to the draft determination: Australian Energy Council, p 5; Snowy Hydro, pp 2-3.

51 For a theoretical discussion of the underlying economic theory, see Hal R. Varian, "Price Discrimination and Social Welfare", American Economic Review, September 1985, Vol. 75, No. 4, pp 870-875.

52 Submissions to the Draft Determination by Origin, p 2; CS Energy, p 3

53 Submission to the directions paper by AEMO, p 3.

54 Submission to the Draft Determination by Delta, p 2.

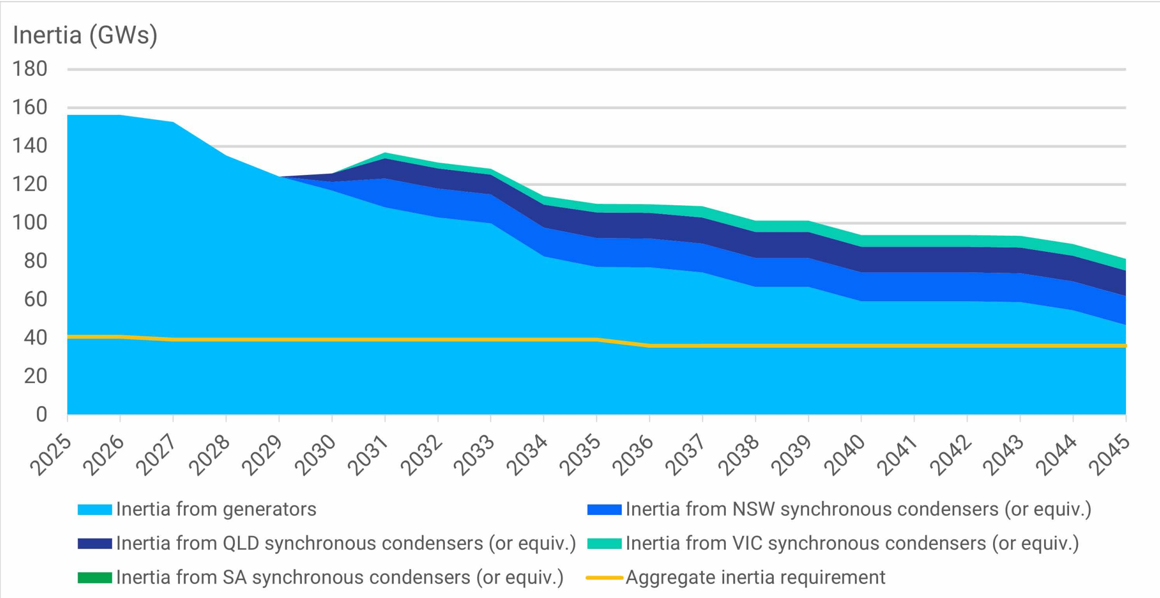
55 AEMC, draft determination, pp 26-31.

3.3 Expected inertia supply greatly exceeds minimum requirements over the foreseeable horizon

Through analysis performed for our directions paper and draft determination, the Commission has found that there will be significant inertia capacity from synchronous sources when compared to the sum of all binding minimum inertia requirements until 2045 (approximately 39 GWs), based on investment that is required for TNSPs to meet their system strength obligations (see section 3.4).

See Figure 3.3 for an updated estimate of inertia capacity from synchronous sources between now and 2045, and appendix D for a regional breakdown of inertia capacity and requirements.

Figure 3.3: Expected inertia capacity in the NEM mainland exceeds minimum needs to 2045



Source: AEMO, 2024 Inertia Report, 2024 ISP, Generating Unit Expected Closure Year April 2025, inertia provision amounts from MMS DSNAP constraint data. Powerlink, Addressing System Strength Requirements from Dec 2025 - PACR - June 2025; Transgrid, Meeting system strength requirements in NSW PACR; AEMO Vic Planning, Victorian System Strength Requirement RIT-T Project Assessment Conclusions Report; Electranet, Meeting System Strength Requirements in SA PADR; TasNetworks, Meeting the System Strength Standard in Tasmania from December 2025 onward PACR.

Note: For each TNSP PACR or PADR, if an investment was listed for a financial year (e.g. for 2027/28), then it was assumed that it would only be delivered in time for the next calendar year (e.g. 2029) - see section 3.4.1 for more information. That is, we have accounted for any delays that last between 6 and 18 months. The graph excludes any inertia that may be provided from future GFM BESS that are needed for stable voltage waveform requirements.

Note: The four existing synchronous condensers in South Australia are included in the 'inertia from generators' area. All future synchronous condensers are assumed to deliver about 1500 MWs of inertia (see Transgrid PACR, p 33), because we expect that TNSPs will install synchronous condensers with flywheels - see section 3.4.2 for more information.

Note: The aggregate requirement is equal to the binding inertia requirement in each region, which is either the inertia sub-network allocation or the secure operating level, depending on whether the region has a credible risk of islanding. See appendix D.1 for more detail on the binding requirements.

Note: For regional supply-demand graphs, see appendix D.

Under the new inertia framework implemented through the *Improving security frameworks* rule, from 1 December 2027, TNSPs must ensure that their region has sufficient inertia available to meet their binding inertia requirements, as determined by AEMO in the annual inertia report published three years prior.[56] This replaced the previous 'shortfall' framework, where TNSP procurement was only required if AEMO declared a shortfall through their annual reports. For a more detailed description of the current inertia framework, see section 4.4 of our directions paper.

56 NER, clause 5.20B.2 and 5.20B.4

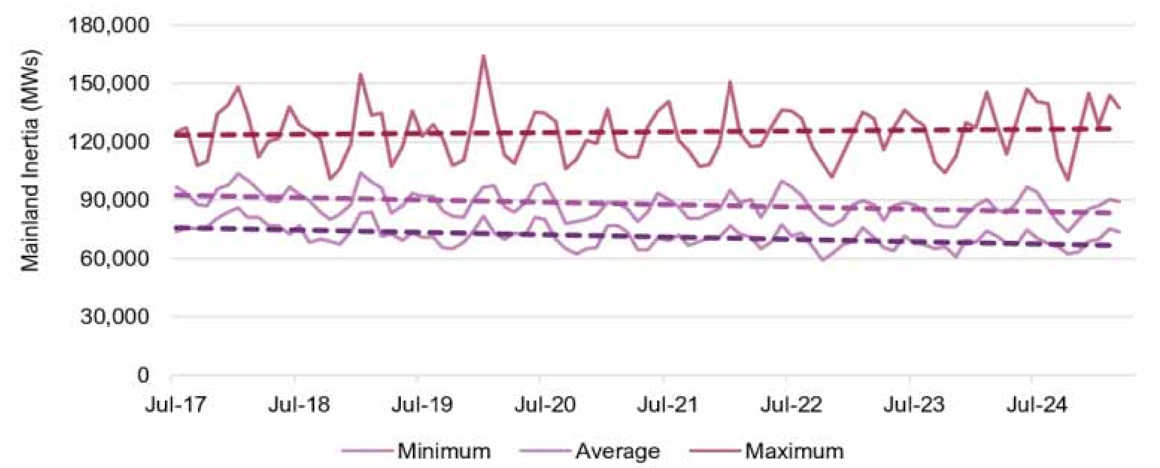
Through network investment and contracts with market participants to meet their system strength obligations, TNSPs are likely to simultaneously meet their inertia obligations without the need for additional synchronous condensers or non-network contracts. This is supported by AEMO's 2025 Inputs Assumptions and Scenarios Report, which states that:[57]

> AEMO's security assessments as part of the 2023 and 2024 NSCAS reports concluded that system strength would be the most onerous security requirement over the coming decades, and that delivering adequate services to meet those needs was likely to substantially resolve the need for additional inertia or voltage control investment. For example, technology solutions may include assets such as high-inertia synchronous condensers, or grid-forming technologies capable of providing both voltage stabilisation and synthetic inertia services. In the ISP, AEMO will validate that all modelled outcomes satisfy the latest inertia requirements as published on AEMO's website. The costs associated with meeting these requirements are assumed to be second order, and therefore captured as part of delivering adequate system strength solutions (e.g. by ensuring some synchronous condensers have flywheels).

The Commission acknowledges that, despite the capacity oversupply indicated by Figure 3.3, there may be dispatch intervals where normal energy market outcomes result in an insufficient amount of inertia being online. In those cases, we would expect that AEMO would use its new enablement procedures to select the least cost combination of system security contracts to meet the inertia gap, as close as practicable to real-time. See section 3.6 discussion on this point.

However, as shown in Figure 3.4, historical observed inertia levels have not dropped below 60,000 MWs in any dispatch interval up to July 2025. Although the future retirement of large synchronous generators (particularly if these occur earlier than expected) will cause the observed real-time inertia levels to decrease, this will be offset by the large amount of inertia that will be provided as a result of meeting minimum system strength requirements.

Figure 3.4: Monthly minimum, average and maximum mainland inertia, 2017 to 2025



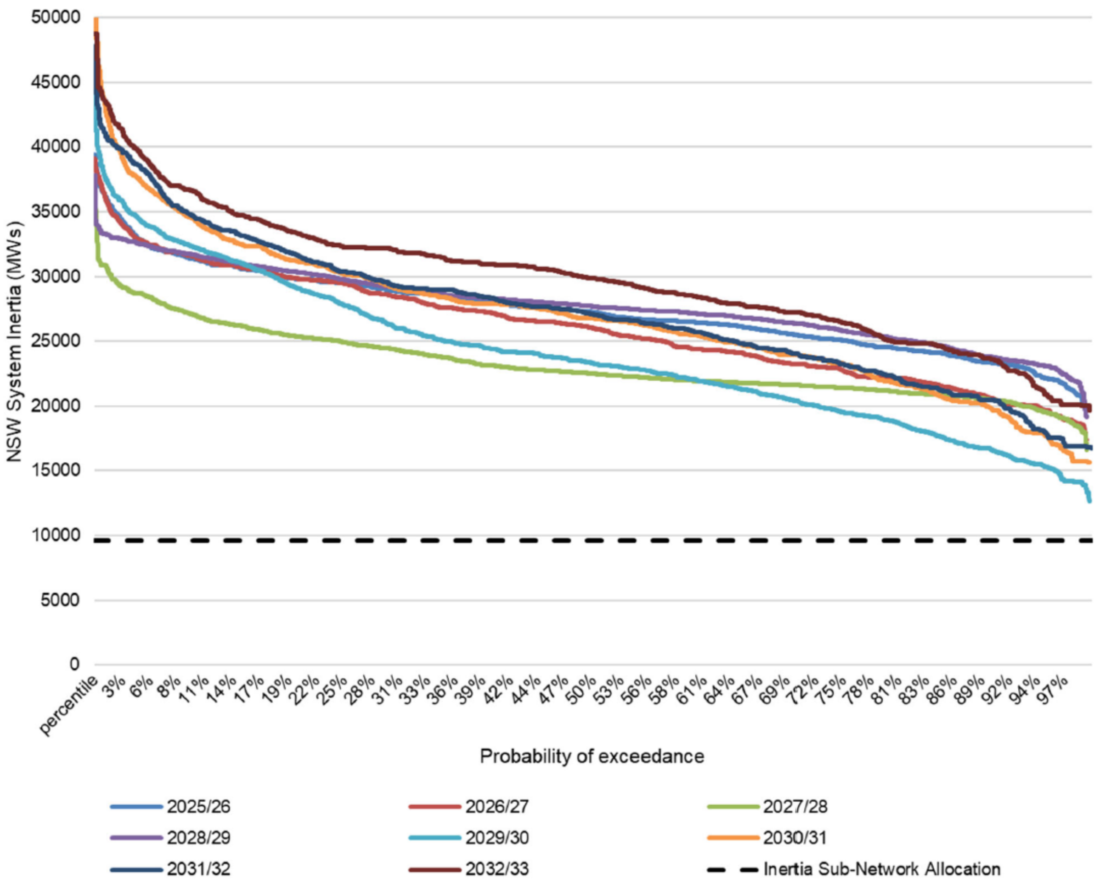
Source: AEMO, Technical Review of the NEM Frequency Control Landscape, p 19.
Source: AEMO notes that this is an estimate based on the known inertia constants of generating units online at any one time, and not a real-time 'true' measurement - see p 18 of its report above.

57 AEMO, 2025 Input Assumptions and Scenarios Report, p 202.

However, as Tesla noted in its submission to the draft determination (see page 3), synchronous condensers are susceptible to angle stability issues, which could become more prevalent throughout the transition. The Commission expects that networks, in fulfilling all of their NER obligations under Schedule 5.1 and Schedule 5.2, should ensure that the location of their synchronous condensers do not cause or exacerbate unstable or undamped oscillations (see clauses S5.1a.3 and S5.1.8); and that their synchronous condensers meet the technical requirements under Schedule 5.2, especially with respect to disturbance ride-through capability (S5.2.5.5 and S5.2.5.5A). The Commission also expects that, in the future, synchronous condensers may not be the only solution to meet minimum system strength requirements - see section 3.4.3 for more discussion on this point.

As part of its project assessment conclusions report (PACR), Transgrid performed modelling to determine whether addressing the more urgent system strength requirements would satisfactorily meet their inertia sub-network allocation, as per their obligations.[58] Under its preferred portfolio option (which has its first synchronous condenser commissioned by March 2029), the inertia supplied by its synchronous condensers for system strength will result in Transgrid fulfilling its foreseeable inertia obligations.

Figure 3.5: Forecast inertia levels in NSW under Transgrid's preferred portfolio option



Source: Transgrid, submission to the draft determination, pp 2-4; PACR, pp 70-71.
Note: The forecast assumes that synchronous generators are re-dispatched (or 'enabled') to meet system strength gaps (not inertia gaps) through AEMO's security enablement procedures.

58 Transgrid, submission to the draft determination, pp 2-4; PACR, pp 70-71.

3.4 On the supply side, meeting system strength requirements is likely to deliver substantial inertia

3.4.1 TNSPs have completed their system strength RIT-Ts which, on the basis of information known to us, will see approximately 23 new synchronous condensers commissioned in the NEM by 2037

Following the *Efficient management of system strength on the power system* rule in 2021, TNSPs have obligations to ensure that there are:

- sufficient three phase fault levels at each system strength node throughout their network (commonly referred to as **minimum system strength requirements** or **minimum fault current**)
- stable voltage waveforms for the level and type of inverter based resources as projected by AEMO (commonly referred to as **efficient levels of system strength** or **stable voltage waveform support**).[59]

Box 2: System strength service providers and inertia service providers are, at the time of writing, equivalent to TNSPs

Under the NER, the obligations outlined above are placed on System Strength Service Providers (SSSP). The SSSP for a region is:

1. the TNSP for the region; or
2. if there is more than one TNSP for a region, the jurisdictional planning body, as nominated by the relevant Minister; otherwise the Co-ordinating Network Service Provider.

Similarly, the obligations under the inertia framework are placed on Inertia Service Providers. The Inertia Service Provider for an inertia sub-network is:

1. the TNSP for the inertia sub-network; or
2. if there is more than one TNSP for the inertia sub-network, the jurisdictional planning body, as nominated by the relevant Minister.

For simplicity, throughout this determination, we refer to TNSPs when talking about both the system strength and inertia frameworks. This is because, at the time of writing, SSSPs and Inertia Service Providers are equivalent to TNSPs.

Source: NER, clause 5.20B.4(a) and 5.20C.3

TNSPs must also provide information in their Transmission Annual Planning Reports about how they plan to meet their obligations, as well as information about their modelling methodologies, assumptions and results used in their plans.[60] They are also generally required to apply the RIT-T to analyse the costs and benefits of potential system strength investments to maximise net economic benefits.[61]

Under the RIT-T process, TNSPs must also consider all credible options equally, which include both network and non-network options (see section 4.3 for more information). However, due to current technical feasibility, TNSPs have only considered synchronous sources as credible options to meet minimum levels for now (see section 3.4.3 for more information).

Almost all TNSPs have recently completed their first system strength RIT-Ts under the new framework described above. We recognise that these RIT-Ts are the first of their kind and have had to grapple with challenging issues, including how to value non-network security options. We

59 NER, clause S5.1.14.

60 NER, clause 5.20C.3.

61 AEMC, *Efficient management of system strength*, final determination, p 110. NER clause 5.16.3 includes conditions for an exemption from applying the RIT-T, while clause 5.15A.3 allows for system strength projects deemed as actionable ISP projects to undergo a shorter RIT-T process.

expect that insights gained from these completed RIT-Ts will be applied to future RIT-Ts, resulting in more effective and streamlined processes.

As a result of the technical and economic modelling performed by these TNSPs, in conjunction with the joint planning undertaken between TNSPs and AEMO,[62] TNSPs have begun procuring several synchronous condensers as well as contracting with non-network providers of system strength solutions (for example, non-network synchronous condensers as part of future or existing synchronous plant, or grid-forming BESS).

Currently, based on TNSPs' preferred options in their Project Assessment Conclusions Reports (PACRs) (and in the case of Electranet, its Project Assessment Draft Report (PADR)), approximately 23 new synchronous condensers are required for minimum system strength requirements throughout the transition. However, as noted in section 3.2.3, we have used TNSPs' preferred options as a proxy for the expected investments that will meet minimum system strength requirements. The Commission notes that other technologies, besides synchronous condensers, may be used to meet minimum system strength requirements in the future - see section 3.4.3.

In their submissions, various stakeholders noted their concern about the potential delays in procuring and commissioning synchronous condenser delays.[63] To account for this in our analysis, we have built our supply-side analysis based on a conservative scenario of synchronous condenser rollout timings, building in a 6 to 18 month buffer for the deployment of each synchronous condenser.

For Transgrid and AEMO Victorian Planning, investments that were listed as occurring in a particular financial year (e.g. for 2028/29) have been assumed that it would only be delivered in time for the next calendar year (e.g. 2030) for the purposes of the table above. For Powerlink, investments are listed as being delivered by March or June of a particular year (e.g. June 2030); these were assumed to be delivered in time for the next calendar year (e.g. 2031) for the purposes of the table above.

However, we note that Transgrid's preferred portfolio option in its PACR is slower than two other 'accelerated' portfolio options, both of which have higher net benefits according to its modelling. Under this scenario, the first synchronous condensers are expected to be commissioned by around May 2028, which is about ten months faster than its preferred credible option. Transgrid is engaging with relevant suppliers and stakeholders to maximise the chance that these accelerated options are realised.[64] However, to maintain the conservative scenario of our supply-side analysis, we have not brought these synchronous condensers forward, where they would also supply inertia earlier.

See Table 3.2 for a breakdown of the number and timing of these synchronous condensers, and Figure 3.6 for their approximate location.

62 NER, clause 5.14.4.

63 Submissions to the draft determination: AGL, p 2; AEC, p 4; EnergyAustralia, p 4; CS Energy, pp 1-2, 5; Tesla, p 2.

64 Transgrid, Meeting system strength requirements in NSW PACR, p 98.

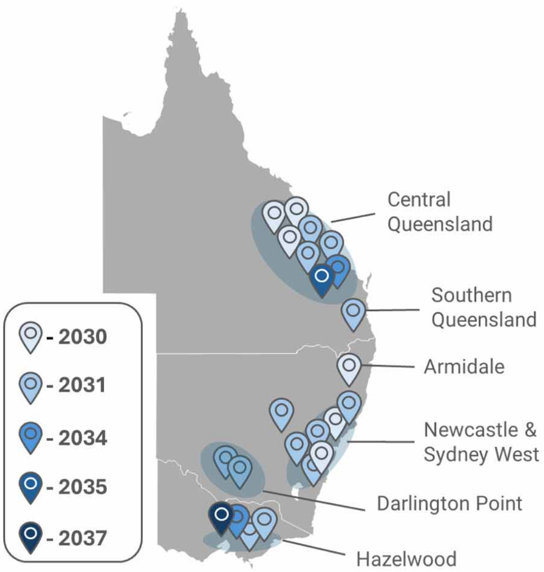
Table 3.2: Expected number of new synchronous condensers needed for minimum fault level requirements

TNSP	By 2030	By 2031	By 2034	By 2035	By 2037	Total
Powerlink (Qld)	3	4	1	1	0	**9**
Transgrid (NSW)	3	7	0	0	0	**10**
AEMO Victorian Planning (Vic)	0	2	1	0	1	**4**
Electranet (SA)	0	0	0	0	0	**0**
TasNetworks (Tas)	0	0	0	0	0	**0**
Total	**6**	**13**	**3**	**1**	**1**	**23**

Source: Based on the preferred portfolio options from TNSP PACRs and PADRs. See Powerlink, Addressing System Strength Requirements from Dec 2025 - PACR - June 2025; Transgrid, Meeting system strength requirements in NSW PACR; AEMO Vic Planning, Victorian System Strength Requirement RIT-T Project Assessment Conclusions Report; Electranet, Meeting System Strength Requirements in SA PADR; TasNetworks, Meeting the System Strength Standard in Tasmania from December 2025 onward PACR.

Note: The table above excludes four existing synchronous condensers in SA and one existing synchronous condenser in Vic, which will still be needed to meet minimum system strength requirements. It also excludes seven synchronous condensers that may be needed for the New England REZ, which may be delivered by EnergyCo instead of Transgrid and are predominantly needed for stable voltage waveform support.

Figure 3.6: Locations of expected synchronous condensers needed for minimum fault level requirements



Source: TNSP PACRs and PADRs (see sources in Table 3.2).

Note: Locations are not precise and are indicative only. The year that a synchronous condenser is assumed to be delivered by is consistent with Table 3.2 - see notes underneath Table 3.2. Electranet and TasNetworks do not expect that new network synchronous condensers are required for minimum fault level requirements, therefore South Australia and Tasmania are not depicted.

3.4.2 These synchronous condensers for minimum system strength will also provide inertia

Despite the fact that these synchronous condensers are being procured to meet system strength requirements, they will also provide inertia due to the rotational kinetic energy of the condenser's rotor.[65] Further, if these synchronous condensers are installed with flywheels (as was the case with the Davenport and Robertstown synchronous condensers in South Australia), they will provide substantial amounts of inertia (with the specific amount provided dependent on the size of the flywheel).

One of the changes introduced by the *Improving security frameworks* rule change was to align the regulatory and procurement timelines of the inertia framework with the system strength framework.[66] This allowed TNSPs to better coordinate solutions that provide both inertia and system strength over the same timeframes, ensuring that consumers do not unnecessarily incur costs twice. The changes to the inertia framework commenced on 1 December 2024, with TNSP inertia procurement obligations formally commencing on 1 December 2027, when TNSPs must continuously make available sufficient inertia to meet their binding inertia requirements.[67]

In the interim, the AER has provided guidance on how TNSPs can consider the provision of inertia by synchronous condensers. The AER has stated that it expects that, wherever a synchronous condenser forms part of a preferred option to meet system strength requirements, the incremental cost of a flywheel would be considered to be prudent and efficient expenditure.[68]

3.4.3 Currently, synchronous sources are the only credible options to supply minimum levels of fault current

In order to meet minimum system strength (fault current) requirements, predominantly driven by coal unit exit, TNSPs are currently relying on synchronous machines only. This reflects current industry understanding where protection-quality fault current provision from grid-forming inverters is yet to be demonstrated - see Box 3 for a discussion on this topic.

However, TNSPs have recognised that grid-forming BESS could provide protection-quality fault current in the future for minimum levels, as well as providing stable voltage waveform support for efficient levels above the minimum. This has been factored this into their RIT-T cost benefit analyses.

For example, in its modelling, Transgrid included grid-forming batteries contributing to meeting minimum system strength requirements from 2032/33. Powerlink included a credible option for modelling where grid-forming BESS provide fault current from 2028/29, as well as including a RIT-T reopening trigger in the event this becomes technically feasible.[69]

65 Synchronous condensers (without flywheels) are estimated to have inertia constants between 1.0 and 3.6 seconds - see our directions paper, p 13.

66 AEMC, *Improving security frameworks*, final determination, pp 25-26, 32-33.

67 NER, clause 5.20B.2(g) and 5.20B.4.

68 AER, Efficient management of system strength framework - Guidance Note - 16 December 2024, pp 31-32. In AEMO's 2025 Electricity Network Options Report, the cost of a flywheel is estimated at $9 million - see page 202.

69 Transgrid, Meeting system strength requirements in NSW PACR, p 44; Powerlink, Addressing System Strength Requirements from Dec 2025 - PACR - June 2025, Portfolio 1A, and pp 48-50.

Box 3: Protection-quality fault current is essential for the correct operation of network protection systems, voltage control devices and overall system stability

Under the system strength framework, minimum system strength requirements solely relates to three phase fault level, or three phase fault current. This fault current is required for the correct operation of the vast number of protection systems that exist throughout the power system, and which are critical to its safety and security. If protection systems do not operate as intended, then the risk of cascading outages due to small disturbances can be extremely large, due to the severely limited ability of the power system to quickly isolate or clear faults.

Additionally, the three phase fault level at a specific location is generally inversely proportional to the system impedance at that location. Because voltage control devices are tuned based on the range of system impedances they are likely to experience, ensuring adequate levels of fault level helps reduce and contain the maximum impedance (i.e. low system strength conditions) that plant may experience, improving power system stability.

In order to meet the obligations under S5.1.14, AEMO and TNSPs consider that, currently, the only credible sources of protection quality three phase fault current are synchronous machines. This is because:

- the design of many protection systems depend on the fault current responses from synchronous machines, especially legacy protection systems which were designed in an era where only synchronous generation existed.
- the fault current contribution from grid-forming inverters may not be sufficiently substantial (due to current limitations) or similar enough to synchronous fault current contributions to guarantee the correct operation of these protection systems.
- there is limited (but growing) experience with the utilisation of grid-forming inverters for supplying protection quality fault current, which is needed to test existing and new protection schemes.

In its 2024 TPSS, AEMO stated that there is a knowledge gap in international research in the capability of grid-forming inverters to provide protection quality fault level.[1] It also stated it is engaging with TNSPs to specify studies to increasing understanding of the ability for GFM inverters to provide protection quality fault current and to help guide inverter manufacturers on evolving product capabilities.

By TNSPs using grid-forming inverters to provide stable voltage waveform support, the operational experience and power system and protection studies that can be conducted will improve collective engineering understanding. This will pave the way for future demonstrations of grid-forming inverters providing protection quality fault current.

Source: AEMC, *Effiicient management of system strength on the power system*, draft determination; AEMO, May 2024 Update to the 2023 Electricity Statement of Opportunities, p 43; AEMO | Research Priorities, p 8; AEMO, 2024 Transition Plan for System Security, p 44; Transgrid, Meeting system strength requirements in NSW, pp 44, 125-127; Powerlink, Addressing System Strength Requirements from Dec 2025 - PACR - June 2025, p 49.

Note: [1] AEMO, 2024 Transition Plan for System Security, p 44.

3.4.4 The cost or timing of meeting system strength obligations would not be avoided or offset by a real-time market for inertia

The Commission heard strong stakeholder concern that meeting minimum system strength requirements in the NEM is likely to result in significant capital expenditure in the NEM.[70] Other stakeholders raised concerns that the Commission did not consider the full benefits of a real-time market for minimum inertia. For example, Snowy Hydro submitted that we should compare the

70 Submissions to the draft determination: EnergyAustralia, p 4; Snowy Hydro, p 2; ENGIE, p 2.

costs of the inertia market to the costs of installing 20 new synchronous condensers, costing in excess of a billion dollars.[71]

We consider it inaccurate to attribute the costs of these synchronous condensers to the provision of inertia. This is because the timing and location of the synchronous condensers is being driven by minimum system strength requirements (and current engineering knowledge of what is acceptable to meet these levels), and not by inertia. HoustonKemp assessed both the incremental costs of adding a flywheel to a synchronous condenser to maximise the inertial response, and the potential costs of investing in a synchronous condenser purely to provide inertia (and not for system strength). The latter was not found to be cost-effective.[72]

Although decreased synchronous generation is likely to result in some dispatch intervals where there may be insufficient inertia, it is very unlikely that this would be unaccompanied by a simultaneous but more locational and urgent minimum system strength requirement.[73] This is due to the fact that the largest sources of both fault current and inertia are large thermal units, many of which are expected to retire throughout the transition.

Therefore, if a real-time market for minimum inertia were to exist now (and was substituted for the existing TNSP procurement and AEMO enablement framework introduced under ISF), it would not be able to satisfactorily resolve the system strength gaps that would arise alongside inertia gaps, because the more constraining requirement will almost always be minimum system strength. The investments outlined above in section 3.4.1 would still be required to meet minimum system strength requirements in this hypothetical scenario. If these synchronous condensers are delayed, then AEMO would likely have to consider alternative options to maintain system security, and may have to direct existing thermal plant more regularly - at least, until grid-forming batteries can satisfactorily provide protection-quality fault current.

Moreover, fault current and inertia are distinct services; while synchronous units can provide both services concurrently, the locational nature of fault current gaps would mean that only one or two specific incumbent synchronous units may be able to satisfactorily resolve these gaps. As such, a need to enable these units online in operational timeframes for fault level is required, and is fulfilled by AEMO's security enablement procedures - see section 3.6 for more information.

As such, the current planned timing, size and cost of the planned synchronous condensers would not be affected in a counterfactual scenario where minimum inertia was being procured in real-time. As explained in section 3.1, our cost-benefit analysis centred on exploring the benefits of procuring additional inertia, which was found to be too small to currently justify a need for a real-time inertia market.

However, it is possible that system strength requirements become less urgent than inertia in the future, where grid-forming inverters (and any other new technologies) could provide both inertia and minimum system strength (protection quality fault current), simultaneously.[74] This is one of the many metrics that the Reliability Panel could consider in its assessment of inertia conditions to monitor whether operational procurement of inertia becomes more beneficial - see section 3.8.

71 Submission to the Draft Determination by Snowy Hydro, p 2.

72 HoustonKemp Economists, *Evaluating market designs for inertia services,* December 2024, pp 16-17, 52-58.

73 For example, AEMO's 2024 Inertia report forecasts that, without any additional investment or operational intervention, in 2027-28, Queensland and Victoria may have a few dispatch intervals where there is insufficient inertia against minimum inertia requirements. However, the 2024 System Strength report forecasts fault level shortfalls for 2027-28 at several system strength nodes, which were driven by the expected retirement of Callide and Yallourn units.

74 Additionally, AEMO is progressing work to better quantify, understand and collaborate with inverter manufacturers on the capabilities of grid-forming inverters to supply protection quality fault current - see AEMO | Research Priorities, p 8; AEMO, 2024 Transition Plan for System Security, p 44.

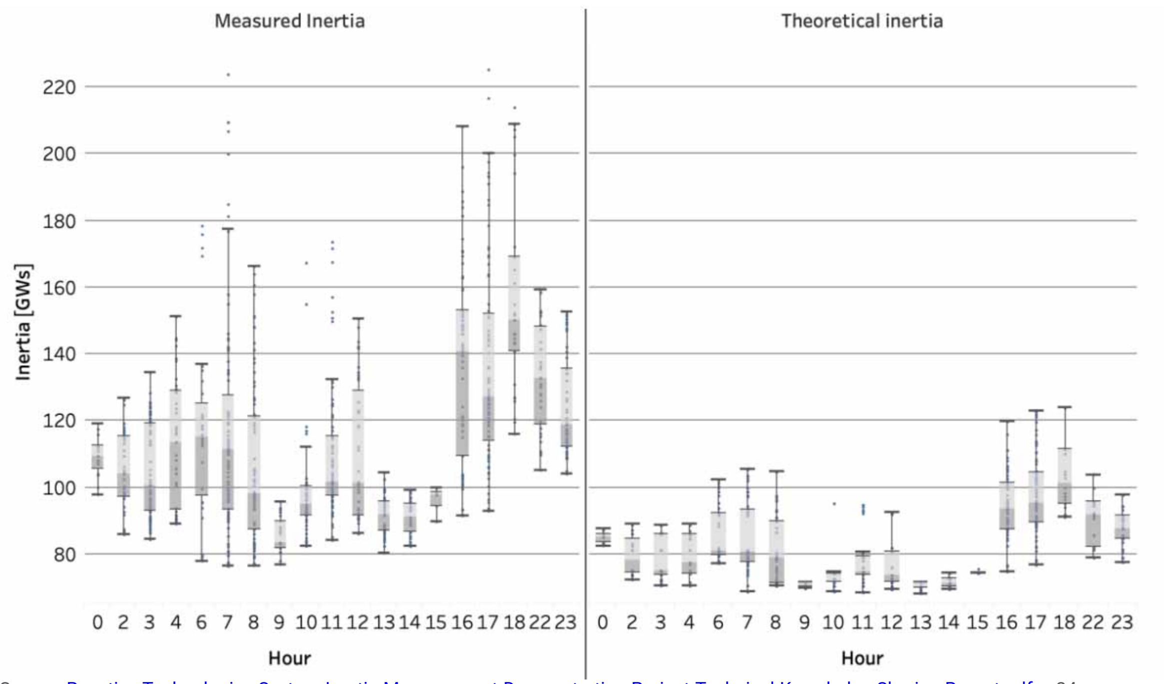
3.4.5 A significant supply of load side inertia may also be present in the NEM

In AEMO's market management system (MMS), there are currently monitoring constraints that estimate the level of real-time inertia that is present in each region in any dispatch interval, and that would be present over the pre-dispatch and seven-day horizon. However, the estimates are solely based on the known inertia constants of each online synchronous generator, and do not currently account for any sources of inertia that AEMO does not have visibility over (for example, large loads). Figure 3.4 is based on this theoretical estimate.

In 2023, a trial conducted by AEMO and Reactive Technologies sought to gather more accurate, real-time data about the amount of inertia that is available in the NEM in real-time. To measure real-time inertia, Reactive Technologies' equipment, along with participant inverter-based plant, injected small modulated signals into the power system and observed the frequency response of the overall power system. Based on the modulated signal and accompanying frequency response, the amount of inertia available can be calculated and more directly measured, without having to rely on estimates or knowledge about the inertia constants of synchronous generators, or whether those generators are currently synchronised.

Using this method, the real-time measurements yielded inertia values that were, on average, 38% higher than AEMO's normal estimates. See Figure 3.7 for a visual comparison of the distribution of inertia measured by Reactive Technologies' method against AEMO's theoretical estimate of the same dispatch intervals.

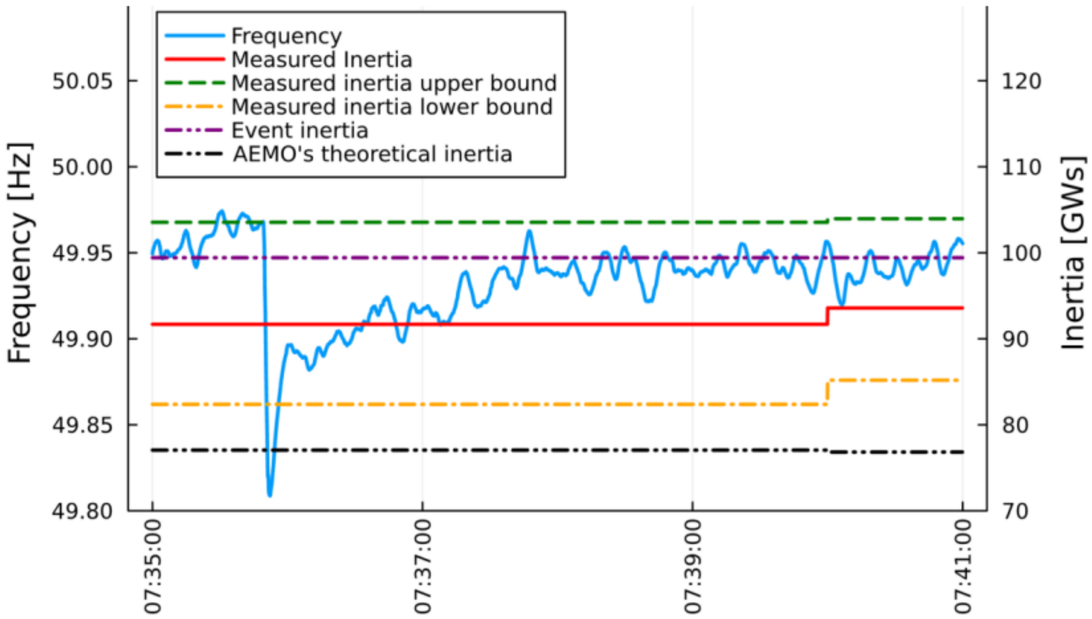
Figure 3.7: Distribution per hour of measured inertia and theoretical inertia in the NEM



Source: Reactive-Technologies-System-Inertia-Measurement-Demonstration-Project-Technical-Knowledge-Sharing-Report.pdf, p 24.

In addition, the real-time measurement trial was active during a contingency event on 26 September 2023, where Kogan Creek, operating at 517 MW, tripped. Frequency data from phasor measurement units allowed the comparison of Reactive Technologies' measurement method (red) and AEMO's estimate (black) against the 'true' amount of inertia (purple), present on the system - see Figure 3.8 below.

Figure 3.8: Frequency, measured inertia and calculated inertia during a trip of Kogan Creek on 26 September 2023



Source: Reactive-Technologies-System-Inertia-Measurement-Demonstration-Project-Technical-Knowledge-Sharing-Report, p 30.

This suggests that the real-time methodology that was trialled is more accurate than AEMO's theoretical estimate, based on known inertia constants. The higher levels of inertia, measured by the trial, also suggests that there is a significant amount of inertia that is 'hidden', or not accounted for, by AEMO in its estimates. This is conjectured to be load-side inertia provided by industrial motors, or other synchronous sources.

3.5 Credible contingencies are not likely to drive increases in minimum inertia requirements

In its submission to the draft determination, CS Energy considered that the future nature of contingency events may increase inertia demand, citing AEMO's recent 2025 GPSRR.[75] This suggests that minimum inertia requirements (in aggregate, about 39 GWs, as indicatively shown in Figure 3.3) may increase in the future, as larger credible contingencies eventuate on the NEM.

AEMO's GPSRR notes that the magnitude of **non-credible** contingencies may increase in the future due to large renewable energy zones (REZs) or other similar new network topologies, and discusses the associated challenges of these increasing contingency sizes.[76] Accordingly, one of its priority actions is to analyse and review the management of non-credible contingencies.

However, AEMO's annual determination of inertia requirements involves determining the minimum amount of inertia required to continuously operate the system in a *secure operating state*.[77] The definition of *secure operating state* is directly linked to ensuring that the system will remain in a satisfactory operating state after any **credible** contingency (but not a non-credible contingency).

75 CS Energy, submission to the draft determination, p 2.

76 AEMO, 2025 General Power System Risk Review, pp 37-43.

77 NER, clause 5.20B.2.

Therefore, the current inertia framework considers all credible contingencies, but not any possible non-credible contingency sizes, which could potentially be extremely large.

Accordingly, the Commission considers that the size of **credible** contingencies is not likely to increase. This is because designing a network topology with a larger credible contingency than present-day maximum sizes (approximately 750 MW) would impose many other significant adverse effects on system security, such as voltage and transient instability. Procuring extra inertia to cover such large contingencies would not resolve these other adverse effects, as described by AEMO:[78]

> Such future topologies are naturally highly speculative, and as the Paper notes, large contingencies may be rectified by protection schemes. Given this, it seems unlikely that a new topology could give rise to a very large credible contingency size that would not also have a corresponding contingency size rectification. A new topology that results in a very large credible contingency size would have many adverse impacts on the secure power system envelope, of which the resulting increase in inertia requirements would be a relatively minor concern.

Generally, good electricity industry practice dictates that the risk of such large contingencies should be covered through protection schemes, so that their effective contingency size is lowered.[79]

3.6 AEMO has the tools to meet any gaps due to capacity being offline

The Commission acknowledges that, despite the oversupply indicated by Figure 3.3, there may be dispatch intervals where normal energy market outcomes result in an insufficient amount of inertia being online. In those cases, we would expect that, from 2 December 2025, AEMO would use its new enablement procedures to select the least cost combination of system security contracts to meet any system security gaps, as close as practicable to real-time.

To ensure that system security contracts are efficiently enabled, the ISF rule gave AEMO a new enablement power that aims to optimise the enablement of all system security contracts to meet any gaps in minimum security requirements in operational timeframes.[80] AEMO has recently published its final Security Enablement Procedures which sets out:[81]

- the determination of real-time minimum inertia, system strength and NSCAS requirements, which will be available to all market participants through constraints in the market management system (MMS)
- the assumptions that will be used when determining gaps against minimum security requirements
- the form and content of enablement instructions to Registered Participants
- the minimum financial parameters that must be given to AEMO and how those parameters will be incorporated for its optimisation of contracts

78 AEMO, submission to the directions paper, p 3.

79 For example, in Tasmania, generator contingencies above 144 MW participate in emergency frequency control schemes, where they may exceed the 144 MW maximum contingency only if they procure load shedding equal to their generation in excess of 144 MW - see Reliability Panel, 2019, Review of the Frequency operating standard — stage two, pp 12-17.

80 *System security services* will be defined in the NER as a *system strength service, an inertia network service*, an *NSCAS* or a *transitional service*; see clause 4.4A.2 of Schedule 5 of the ISF rule. The *minimum system security requirements* will also be defined as the operational aggregate of the minimum inertia requirements, system strength requirements, any relevant NSCAS needs and any transitional services required for secure operation; see clause 4.4A.3 of the ISF rule.

81 See AEMO's Security Enablement Procedures.

- the automated procedure and timelines by which AEMO will determine an enablement schedule, based on pre-dispatch information, financial information from contracts, and technical limitations of plant (for example, minimum start-up times).

ENGIE, AGL and Snowy Hydro noted their concern that the Commission's draft decision does not allow existing generators to receive compensation for their inertia, while TNSPs would be remunerated for their investments.[82] The Commission does not consider this to accurate, as both existing and future synchronous generators, grid-forming batteries and any other technology capable of providing fault level, stable voltage waveform support or inertia can be compensated for their security provision under the existing security frameworks.

To meet their system strength and inertia obligations, TNSPs have begun contracting with both synchronous generators and grid-forming batteries for their fault current or stable voltage waveform contribution, respectively. See Table 3.3 for an overview of expected grid-forming BESS that will be contracted for stable voltage waveform support.

Table 3.3: Grid-forming BESS expected to be contracted for stable voltage waveform support

TNSP	Grid-forming BESS (MW)
Powerlink (Qld)	2,150
Transgrid (NSW)	4,950[A]
AEMO Victorian Planning (Vic)	1,250
Electranet (SA)	0
TasNetworks (Tas)	0

Source: Powerlink, Addressing System Strength Requirements from Dec 2025 - PACR - June 2025; Transgrid, Meeting system strength requirements in NSW PACR; AEMO Vic Planning, Victorian System Strength Requirement RIT-T Project Assessment Conclusions Report; Electranet, Meeting System Strength Requirements in SA PADR; TasNetworks, Meeting the System Strength Standard in Tasmania from December 2025 onward PACR.

Note: [A] Transgrid expects that 8,150 MW of BESS may need to be contracted for stable voltage waveform support by 2044/45.

If these batteries are capable of providing synthetic inertia, then they may also be enabled by AEMO to meet minimum inertia requirements. Similarly, synchronous plant that are contracted for system strength could also be enabled for their inertia provision, and be compensated through their contract with the TNSP.

Through these contracts, market participants and future connecting plant have the opportunity to be compensated for their security service provision. Daily and annual reporting and transparency obligations on AEMO will provide interested asset owners with information that can assist in the development of a competitive proposal to their respective TNSP.[83]

3.7 We do not miss out on benefits by waiting because technical work and system security reforms are still progressing

The Commission's analysis and consideration of all stakeholder feedback is that implementing a real-time inertia market at this time would not result in net benefits. However, an important aspect of this decision is that we do not lose the potential benefits that could arise from the operational procurement of inertia by deferring implementation. This is because:

82 Submissions to the draft determination: AGL, p 2; ENGIE, p 2; Snowy Hydro, p 2.

83 See Daily reporting for Improving Security Frameworks rule change (DRAFT for comment); AEMC, *Improving security frameworks,* final determination, section 6.3.6.

- technical work that would be necessary for a real time market is already progressing, and AEMO will gain experience in operationally managing inertia through ISF enablement
- we preserve the option value associated with determining the best approach and market design for operationally procuring inertia, especially with the rapid development of grid-forming inverters
- allowing time to embed the *Improving security frameworks* reforms will help ensure they are implemented effectively and at least cost to consumers.

3.7.1 AEMO is progressing technical work that would be necessary for operational procurement

There are several initiatives and work being conducted by AEMO that would improve AEMO's operational management of inertia, as well as system security more broadly. Much of this work would be preconditions and necessary to the implementation of a future real-time market for inertia. For example:

- **Real-time inertia measurement:** Building on a previous real-time inertia measurement trial together with Reactive Technologies and the University of Melbourne (see section 3.4.5), the Commission understands that AEMO is currently exploring future applications of real-time inertia measurement. We agree with Reactive Technologies' assessment that improving AEMO's visibility of the precise quantity of inertia that is available at any time is critical for an efficient operational procurement mechanism for inertia, as well as minimising the risk of over-procurement based on inaccurate estimates of inertia supply.[84]
- **Operational inertia constraints:** AEMO is currently developing operational inertia constraints that will be used for AEMO's enablement of system security services from 2 December 2025.[85] The development of these constraints and their operational impact on the technical envelope may provide AEMO with the experience and knowledge to be able to linearise system requirements for inertia, which would be necessary for real-time procurement within NEMDE.[86]
- **Analysis and quantification of synthetic inertia:** Although AEMO's existing inertia network service specification provides a quantification method for the inertial response of grid-forming batteries,[87] AEMO is progressing work to improve the quantification method, as well as considering whether similar quantification methods could be extended to system strength provision.[88]
- **Type 2 transitional services:** As stated in its submission, AEMO considers there are many potential applications of synthetic inertia yet to be demonstrated.[89] AEMO may utilise the transitional service framework to enter into any trials that will assist it in its real-time management of inertia, system strength or any other security services - which would be necessary for a new real-time procurement mechanism.

The work listed above will contribute to the speed of implementation of a future real-time market, if one is deemed to be beneficial in the future. In other words, little to no time would be lost if work on a real-time inertia market were to commence now, versus waiting for the required technical work above that is already underway to progress further.

For other examples of ongoing and related AEMO technical work, see section 4.1.

84 Reactive Technologies, submission to the draft determination, p 1.

85 AEMO, ISF and IPRR Consultation of Constraint Formulation Guidelines.

86 AEMO stated that it expects that progress will be made in the linearisation of system requirements for inertia, even without an operational procurement mechanism - see AEMO, submission to the draft determination, p 3.

87 See Inertia Requirements Methodology and Inertia Network Services Specification, section A.3.

88 AEMO, AEMO Research Priorities, March 2025, p 8.

89 AEMO, submission to the draft determination, p 5.

3.7.2 We preserve option value by waiting to determine the best enduring approach for providing inertia

There are two primary ways that the approach in this determination preserves option value in the long-term interest of consumers:

1. We preserve the option of implementing a new procurement mechanism for inertia if and when we are confident that it will deliver net benefits to consumers
2. We preserve the ability to make optimal market design choices that are likely to result in enduring consumer benefit, rather than implementing a sub-optimal procurement mechanism.

In relation to the first point, given that inertia is not currently the critical constraint driving security requirements, the Commission's decision to make no rule increases the likelihood that a future decision can maximise long-term consumer benefits, without any associated security risks due to waiting.

The *Improving security frameworks* reforms to the inertia framework, as well as the introduction of AEMO enablement of system security contracts, are yet to fully commence. For example, the new inertia obligations on TNSPs to make available a required amount of inertia (either their sub-network allocation or the secure level) will be binding from 1 December 2027, to meet the projected requirements in the December 2024 AEMO annual report.[90]

As TNSPs are currently in the process of procuring assets and contracting with system security providers and AEMO is developing its enablement tool, the Commission considers it important to maintain regulatory certainty by not amending the current long-term framework (as amended by the ISF rule) through this rule change process.

Significant changes to the inertia procurement framework or to AEMO system security enablement in this rule change process would not promote the NEO. This is because changes to either would likely increase system security contracting costs, may result in consumers incurring costs for tools that may not be used, and would leave industry with an unclear direction as to how to procure and provide inertia and system strength throughout the transition, risking system security.

In relation to the second benefit of preserving option value, there is a wide range of important considerations that would need to be addressed when designing a real-time market. These were discussed in more detail in our directions paper,[91] but some considerations include:

- mitigating potential distortions in the wholesale energy market due to out-of-merit order dispatch related to inertia
- how (and whether) to incorporate the ability of synthetic inertia providers to vary their inertial constants
- power system security concerns associated with constantly shifting distributions of inertia that may arise from real-time procurement.

Many market design choices would benefit from additional technical information, operational experience with synthetic inertia, and greater certainty about the expected mix of suppliers of inertia to inform technical design decisions (for example, the proportion of synchronous inertia providers vs synthetic inertia providers). An optimal market design for the current technical and economic 'state of play' is likely to not be an optimal design for the future. Considering the fast pace of development in inverter capability, and the significant power system effects associated

90 Similarly, the system strength obligations on TNSPs to ensure sufficient fault levels and stable voltage waveform support commences on 1 December 2025, to meet the projected requirements from the 2022 AEMO system strength support.

91 AEMC, directions paper, chapter 8.

with retiring thermal plant and synchronous condenser deployment, we are unlikely to know the right settings and make the right decision choices for a potential inertia market now.

Preserving the option value of determining the best enduring approach to procure inertia means that we can better incorporate new findings, new technologies and the future state of the power system.

3.8 The Commission will task the Reliability Panel to monitor system conditions that would warrant the reconsideration of a real-time market for inertia

Although the Commission considers that there are no net benefits from introducing operational procurement of inertia now, this assessment has come from an analysis of prevailing system and market conditions, and the Commission's reasonable expectation of the future state of those conditions. However, if these conditions evolve in an unexpected way throughout the transition, then the benefits of a real-time inertia market could grow, leading to net benefits for consumers.

Table 3.4 provides a summary of the main metrics that contributed to our final decision, as well as how the metric could change in the future to increase the economic benefit of operational procurement of inertia.

Table 3.4: Inertia-related metrics that could increase benefits of an operational procurement mechanism for inertia

Inertia-related metric	Our current view	How the metric changing would provide benefits
Minimum inertia requirements	Minimum inertia requirements are not likely to increase, because • credible contingency sizes are not likely to increase beyond present-day values (see section 3.5) • committed and future interconnectors will decrease the risk of islanding, reducing regional inertia requirements • Registered capacity in the 1-second FCAS markets is not likely to decrease	If minimum inertia requirements significantly increase contrary to the Commission's expectations and AEMO forecasts, then there could be economic benefits to consumers from using a combination of long-term and operational procurement to procure minimum inertia (for example, see section 7.1.4 of our directions paper).
Cost of long-term inertia procurement for minimum inertia	Foreseeable minimum inertia requirements are all likely to be met as a consequence of TNSPs meeting their system strength requirements (through synchronous condensers and flywheels required for system strength and contracts with market participants).	If the inertia provided by system strength investments was to be significantly less than expected, then there may be economic benefits to consumers from using a combination of long-term and operational procurement to procure minimum inertia.
1-second Contingency	One of the main benefits of procuring additional inertia is to substitute for 1-	If typical 1-second FCAS prices were to increase, then the benefits

Inertia-related metric	Our current view	How the metric changing would provide benefits
FCAS prices	second FCAS contingency responses, whenever it may be cheaper. However, future projections of the 1-second Raise and Lower FCAS prices indicate a decrease in typical market prices, significantly reducing the benefits of procuring additional inertia.	to consumers of procuring additional inertia would also increase.
Value of RoCoF-related constraints	Currently, there are only two RoCoF-related constraints that bind with significant frequency. The current marginal value of relieving these constraints is approximately $275,000 per year, which is very small.	If AEMO determines that the technical envelope of the power system requires more RoCoF constraints to be formulated, then the value to consumers of relieving those constraints through operational procurement of additional inertia could increase.

To closely monitor the evolution of these metrics and to ensure that we do not miss out on potential benefits, the Commission will task the Reliability Panel to monitor these matters through its Reliability and Security Report (RASR) by amending its Terms of Reference.[92]

In the annual RASR, the Commission intends to require the Reliability Panel to:

- publicly report on the metrics listed in Table 3.4, and any other metrics the Reliability Panel considers suitable
- comment on whether and how the metrics are changing, and compare any changes to current expectations
- optionally, comment on what broad influence (for example, magnitude and direction of influence) any changes could have on the net benefits of operational procurement of inertia.

In the RASR, we envision that the Reliability Panel will present both historic and expected future trends of the metrics in Table 3.4, along with any commentary that the Reliability Panel wishes to include. The Panel may come to a view, through this process, that the operational procurement of inertia should be reconsidered. In this case, it could choose to submit a rule change request. Importantly, any decision on implementing a new procurement mechanism in the NER would remain a decision for the Commission through a future rule change process, consistent with our functions.

CS Energy noted its concern that a long lead time for market formulation and investment could mean that, despite the Reliability Panel's formal monitoring role, a market may not be established in time to address potential future inertia shortfalls.[93] We consider that given the large amount of technical work already progressing that is reasonably necessary for the efficient operational procurement of inertia, significant time is not lost by preserving option value (see section 3.7).

92 As an example, see the Commission's Terms of Reference to the Reliability Panel for its Annual Market Performance Review for FY 2024.

93 CS Energy, submission to the draft determination, p 5.

3.8.1 We do not consider prescriptive triggers or methodologies for the Reliability Panel's monitoring of inertia conditions is appropriate

In response to the draft determination, stakeholders generally supported the Commission's proposal to formally task the Reliability Panel to monitor inertia-related system conditions in its RASR.[94] However, some stakeholders wanted the Commission to define 'triggers' to more clearly define when a real-time market would be beneficial, or to prescribe the Reliability Panel's assessment methodology,[95] or considered the metrics were too high-level or qualitative.[96]

We do not consider that specific 'triggers' should be prescribed for reconsidering operational procurement of inertia. The potential costs and benefits of a future real-time market depend on all relevant metrics. It is not possible to distil all factors into a small set of specific triggers that definitively describe when operational procurement would be in consumers' interests. Indeed, by doing so, it may result in unintended consequences where a key factor that should be taken into consideration is missed.

3.9 The Commission supports using real-time markets for system security services, where technically feasible and economically beneficial

A common theme throughout several submissions to the draft determination was the view that the Commission's draft decision does not sufficiently progress the 'unbundling' of system security services.[97] Generally, we have interpreted these stakeholder views as supporting the creation of real-time markets for separately defined security services.

As previously stated in other determinations and public submissions, the Commission considers that the ultimate goal is to independently procure and value security services, wherever technically feasible and economically justifiable.[98] There are many approaches to independently procure and value security services, ranging from regulated, mandated approaches, to decentralised real-time procurement. The right approach should be used for each security service, depending on its technical characteristics and function, and the costs and benefits of its provision.[99] This is also consistent with the Energy Security Board's advice to Energy Ministers in 2021, which stated that there are 'services that may be better suited to structured procurement where spot market arrangements may not be appropriate (either now or ever).'[100]

See Figure 3.9 for current NEM examples of different procurement approaches for different security services.

94 Submissions to the draft determination: AEMO, p 4; ENA, pp 1-2; TasNetworks, p 1; Origin, p 3.

95 Submissions to the draft determination: ENGIE, p 3; EnergyAustralia, pp 4-5.

96 Australian Energy Council, submission to the draft determination, p 6.

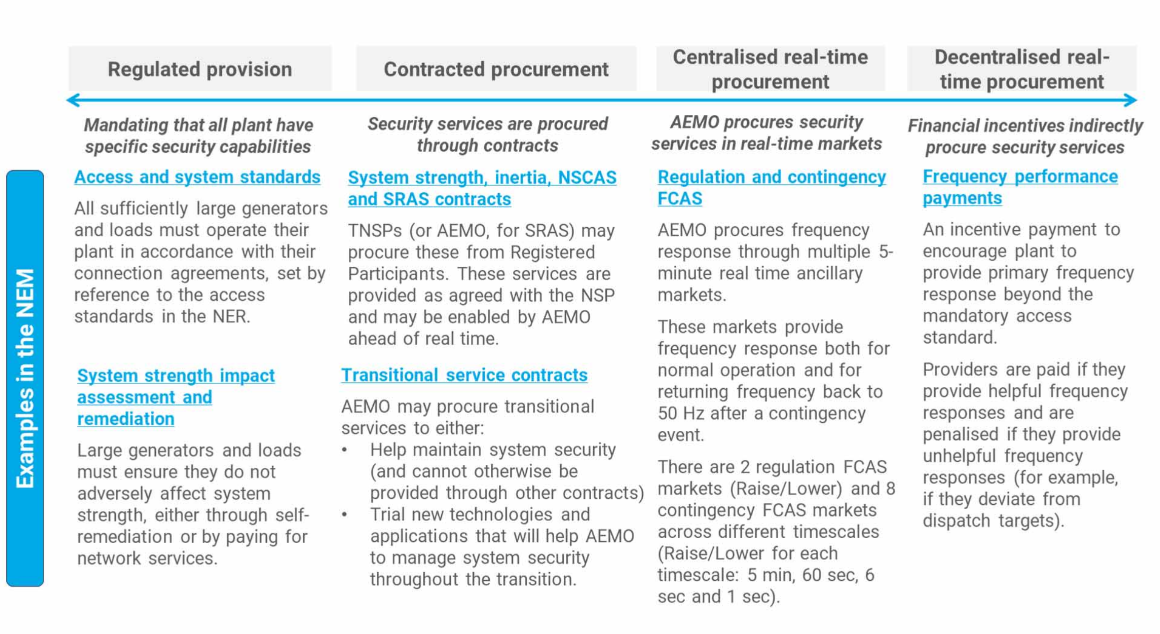
97 Australian Energy Council, p 9; Snowy Hydro, p 4; CEC and AEC, pp 2-4; CS Energy, p 6; EnergyAustralia, pp 1, 5; ENGIE, p 3.

98 AEMC, *Improving security frameworks* final determination, p 118.

99 AEMC, submission to the NEM wholesale market settings review, section 4.4.1, pp 32-34.

100 Energy Security Board, Post-2025 Market Design Final advice to Energy Ministers, Part A, p 28.

Figure 3.9: There are a variety of mechanisms for providing system security services



Source: AEMC
Note: The Commission considers that system strength and inertia are both being independently procured and valued through contracted procurement frameworks.

Although the Commission recognises and acknowledges the economic efficiency that real-time markets can bring (as demonstrated by the FCAS markets), real-time markets are not necessarily guaranteed to be more efficient than other procurement approaches. For example, it would be inappropriate and inefficient to have no mandatory requirements and only real-time procurement for frequency, voltage or fault ride-through capabilities, given that a minimum level of capability from all plant is critical for the safe and secure operation of the power system.[101]

All else being equal, the Commission generally prefers using real-time markets to procure security services, but only where real-time procurement is viable and practical. For example, fault current is highly locational, dependent upon the capabilities of many nearby plant, and requires non-trivial power system studies to plan and remedy insufficiencies. For these reasons, the Commission does not consider that fault current is a security service that would be suitable for real-time procurement for the foreseeable future. Equally, this does not mean that the current system strength framework should never be amended; it means that, when considering future security reforms, the Commission will consider all possible procurement approaches, and determine which approach best achieves the objective of independently procuring and valuing security services, and the NEO.

Our directions paper contemplated the likely market design choices we would have to make for a potential real-time inertia market, such as eligible providers, permitted bid structures, market power considerations and compliance arrangements.[102] These choices may also reasonably differ between different security services. For example, although regulation FCAS and primary frequency

101 NER, clauses S5.2.5.3 to S5.2.5.5A.

102 AEMC, directions paper, pp 50-54.

response are related security services, the real-time procurement mecahnisms for both are quite distinct (see Figure 3.9 above for a description of both mechanisms).

In submissions, some stakeholders considered that AEMO is not progressing enough work that would allow the creation of new real-time markets.[103] CS Energy suggested that an appropriate objective for future technical work could be to 'progress the unbundling of inertia from other security services', with the AEC and EnergyAustralia making similar comments.[104] These comments generally coincided with calls for a new governance framework to oversee AEMO's future security program, which would encourage the creation of real-time market mechanisms. See section 4.4 for more discussion on stakeholder comments for a new governance framework.

As discussed in section 3.7.1, we consider that the AEMO is progressing valuable technical work that would be necessary for the implementation of any future operational procurement mechanism for inertia. However, given that each security service differs in its technical and economic characteristics, it would not be appropriate to apply an objective on AEMO's technical work such that it must lead to the creation of real-time markets for security services. The Commission highlights that AEMO's technical work is absolutely critical to the energy transition (see section 4.1) - but the maintenance and improvement of system security is distinct to market creation or design.[105]

To support AEMO in its management of system security throughout the transition, the *Improving security frameworks* rule:

- explicitly recognised that synthetic inertia can contribute to meeting minimum inertia requirements so that all types of inertia responses (synchronous and synthetic) can be procured and valued
- required AEMO to enable system security services in operational timeframes, and that it must specify (through daily reporting and operational constraints) which security service(s) enablement was needed for
- allowed AEMO to procure Type 1 contracts for broad security services that may not be able to be procured under existing frameworks, but that it must report on how it intends to move away from such contracts through its Transition Plan and by using Type 2 contracts for technical trials.

103 Submissions to the draft determination: CEC and AEC, pp 2-4; ENGIE, p 3; CS Energy, pp 5-6; AEC, pp 8-9; EnergyAustralia, p 5.

104 Submissions to the draft determination: CS Energy, pp 5-6; AEC, pp 8-9; EnergyAustralia, p 5.

105 See AEMC, draft determination, pp 16-17, where we state 'The choice of procurement model for ancillary services or other system security services is separate from the technical envelop that is managed and defined by system operators and regulators.' See also the NEL, s 49(1) for AEMO's statutory functions, which include 'to maintain and improve power system security'.

4 Recent reforms and ongoing work will deliver benefits to consumers

Box 4: Key points in this chapter

There are opportunities to improve information-sharing on technical priorities and security planning

- We encourage AEMO to increase its visibility of its technical work program in its TPSS and how it intends to use its insights to manage system security, so that industry can pursue efficient investment in any new capabilities that may be required for the future power system. Our discussions with AEMO have demonstrated that they are committed to improving transparency on their work in relation to system security.
- Some stakeholders considered that there should be additional requirements relating to the content and development of the TPSS. We consider that the current Rules requirements are appropriate, noting that only one edition of the TPSS has been published.

The transitional services framework allows AEMO to manage system security in a constantly changing and complex energy transition

- Some stakeholders considered that there should be volume-based obligations for how AEMO must use Type 2 contracts. For example, some stakeholders considered that AEMO should be required to progress at least one Type 2 contract per year, or that the Reliability Panel could be tasked to set procurement targets.
- We understand that AEMO has needed time to build up its internal capability and resources required to utilise the framework. The Commission understands that AEMO intends to publish Statements of Needs for Type 2 contracts, prior to the publication of the December 2025 TPSS.
- We maintain our view that fixed obligations are inefficient and can lead to increased costs to consumers because they could incur unnecessary costs from any contracts that have been executed only to meet a regulatory requirement, and not for a beneficial power system trial. In addition, it could give potential transitional service providers excessive negotiating power, with the risks associated with such negotiations being borne by consumers.

TNSP assessment and procurement of non-network options should remain rigorous and clear throughout the transition

- The Commission encourages TNSPs to take opportunities to maximise the transparency of their analysis, modelling assumptions, technical understanding of non-network options, and rationale when selecting the preferred option in system security RIT-Ts.
- Many stakeholders raised concerns about unfair competition between non-network options and network assets, and proposed various amendments to those frameworks. However, the Commission does not consider that further amendments to the RIT-T process, or new obligations on TNSPs for non-network contracts, are in the interests of consumers at this time.
- The recent RIT-Ts were the first time that these issues were considered, and so as we continue to learn about how the RIT-T applies in these scenarios, we would expect that our understanding increases.

- However, we note that some stakeholder issues would likely be considered in a potential future network regulation review that the AEMC has begun work on, which could result in suitable recommendations for rule changes.

Existing frameworks and the Reliability Panel provide sufficient accountability for AEMO's work

- Various stakeholders considered that a new governance framework should be introduced to improve the accountability of AEMO's technical work program, oversee its Type 2 contracting priorities, or to place an objective for AEMO to develop or progress real-time markets.
- The Commission understands that AEMO intends to release Statements of Needs for Type 2 contracts, prior to the publication of its 2025 TPSS. We encourage AEMO to continue keeping stakeholders informed through its TPSS and through other publications.
- We consider that introducing a new governance framework would duplicate existing security frameworks and the existing role of the Reliability Panel, which already has several security-related functions. Over-prescription may also result in unintended consequences due to the additional administrative burden needed to meet regulatory requirements.
- In addition, we do not consider that the Reliability Panel should determine the inertia requirements methodology. This is because AEMO is the only party with the expertise and capability to determine the technical envelope and the set of all credible contingency events for the inertia requirements methodology, so that the Frequency Operating Standard is adhered to.

4.1 There are opportunities to improve information-sharing on technical priorities and security planning

4.1.1 AEMO's technical work and its Transition Plan for System Security are essential to supporting security through the transition

AEMO's technical work program and priorities are essential to supporting the operation of current system security frameworks and for proactively identifying challenges and opportunities for future system security management. It is also important that industry stakeholders are aware of AEMO's work and priorities, so that they can contribute where appropriate, and pursue efficient investment in any new capabilities that may be required for the future power system.[106]

As a result, the Commission introduced a requirement for AEMO to prepare an annual Transition Plan for System Security (TPSS).[107] In this report, AEMO must describe its plan to maintain power system security throughout the transition and its technical understanding of what is needed to achieve security, as well as the work to improve its understanding and any security services that will be required.[108] AEMO must also include information about how it intends to move away from using Type 1 contracts to manage system security, descriptions of known capabilities that could participate in managing system security, and information about the technical priorities it seeks to trial through the use of Type 2 contracts, among other required information.[109]

106 AEMC, *Improving security frameworks*, final determination, pp 117-118.

107 NER, clause 5.20.8.

108 NER, clause 5.20.8(b)(2).

109 NER, clause 5.20.8(c).

In our draft determination, the Commission concluded that ongoing and planned work by AEMO addressed many technical areas where stakeholders wanted greater information and clarity, such as locational inertia requirements and future operational management of inertia.[110]

However, we also considered that there were opportunities to enhance the visibility of AEMO's technical work through future editions of its TPSS.[111] Through its submission to the draft determination, AEMO confirmed that it is progressing a substantial body of work to address stakeholder concerns, and that its discussion of inertia in the 2025 TPSS will be more fulsome than the 2024 TPSS.[112]

There continues to be a significant body of AEMO work relating to inertia and broader system security provision and management in a future power system dominated by IBRs. Examples of such recent work include, but are not limited to:

- AEMO's commencement of its Grid-forming Technology Access Standards Technical Requirements review, which aims to codify the required range of performance standards from grid-forming inverters in the future power system, and builds upon previous AEMO reports and guidelines on grid-forming inverters.[113]
- AEMO's Technical Review of the NEM Frequency Control Landscape, which outlines a list of priority actions and recommendations for AEMO and the Reliability Panel to ensure frequency control remains adequate in the future.
- AEMO's ongoing refinement of its existing Inertia Requirements Methodology and Inertia Network Services Specification, which specifies the minimum technical requirements for grid-forming inverters to be able to provide synthetic inertia, by developing better quantification methods for the MWs equivalent response of BESS.[114]
- AEMO's publication of its security enablement procedures and development of its automated scheduling system, which will manage system strength, inertia, NSCAS and future applicable transitional services in operational timeframes. These will be managed through dynamic constraints that will be publicly available to view in AEMO's Market Management System (MMS).[115]
- AEMO's work on using frequency scanning to identify potential small-signal stability issues that can contribute to the design or retuning of control systems of new IBR connecting to the NEM.[116]
- AEMO's ongoing work to reduce the minimum amount of synchronous generators needed online at any time in South Australia - recently, the minimum number was reduced from two to one.[117]
- AEMO's identification of 29 priority actions for FY2026 in its most recent Engineering Roadmap report (see pp 37-41), which include analysing real world fault-current performance from grid-forming inverters.

110 AEMC, draft determination, section 4.2.2, pp 37-39.

111 Ibid., section 4.2.3.

112 AEMO, submission to the draft determination, sections 3.1-3.2, p 3.

113 AEMO, Voluntary Specification for Grid-forming inverters: Core Requirements Test Framework; see Engineering Roadmap Execution Reports for more related reports.

114 AEMO, Quantifying Synthetic Inertia of a Grid-forming Battery Energy Storage System - Technical Note. See also AEMO's 2024 Inertia Report and 2024 NSCAS report, which outlines regional inertia requirements in a technology-agnostic way and its projections over the next ten years.

115 See AEMO's Improving security frameworks for the Energy Transition page for more information and resources.

116 AEMO, Improving grid stability through frequency scanning and Analysis of Sub-synchronous Oscillations in West Murray Zone Power System in Australia.

117 AEMO, Reduction of Minimum Synchronous Generators in South Australia, August 2025; 2 to 1 minimum Synchronous Units for System Security, Public Industry Webinar.

- AEMO's five research priorities that will enable it to better understand future system needs and future security management, which include the analysis and quantification of grid-forming inverter capability to provide power system requirements such as inertia, system strength and black start capability.[118]

We encourage AEMO to include an overview of its technical work program and a description of how it plans to use the insights from its work in managing the future power system in the upcoming 2025 TPSS.

We note that AEMO uses public webinars to provide forums for interested stakeholders to ask questions, provide feedback and better understand AEMO's development processes for the TPSS.[119] We also encourage AEMO to consider publishing any written industry feedback or submissions to the TPSS, to the extent that this is reasonable and practical (noting there would likely be confidentiality and commercial issues to navigate). This would help promote greater transparency and industry understanding of the TPSS's content and development, as well as AEMO's technical view of managing the technical envelope throughout the transition.

4.1.2 We consider that the TPSS content and consultation requirements are appropriate

In submissions to the draft determination, several stakeholders considered that there should be stricter requirements on the TPSS's development and content. The Australian Energy Council and EnergyAustralia considered that the Reliability Panel should have a broader role in the development of the TPSS, with input into project commencement, a draft report and a final report preview - somewhat mirroring the consultation for the Integrated System Plan.[120] The Australian Energy Council considered that greater Reliability Panel input into the development of the TPSS would:[121]

> avoid the risk of AEMO determining the strategic pathway without sufficient oversight, remove any potential biases, recognise innovation and enable competitive delivery.

Iberdrola, the CEC and the AEC suggested that AEMO could be required to model specific future power system scenarios on how to operate the NEM without coal units, and publish the modelling information.[122] The Commission notes that NER clause 5.20.8(b) already specifies that the purpose of the TPSS is to outline AEMO's understanding of what is needed to achieve power system security in a low- or zero-emissions power system, and clause 5.20.8(c)(3) requires that the TPSS includes such a description. Codifying another layer of prescription in the rules would not be consistent with other AEMO reports, where the objective and content of the report, but not the specific methodology in generating the content, is prescribed in the rules.[123] We note that the Reliability Panel can provide comments on the TPSS, which could include suggesting specific analysis or modelling scenarios. AEMO must respond to all Reliability Panel commentary in its TPSS.[124] In its draft report of its Review of the System Restart Standard, the Panel has in fact recommended specific modelling scenarios that AEMO should include in its TPSS.[125]

118 AEMO, AEMO Research Priorities, p 8.

119 For example, see AEMO's 2024 Transition Plan for System Security Webinar.

120 Submissions to the draft determination: Australian Energy Council, p 10; EnergyAustralia, p 5.

121 Ibid.

122 Submissions to the draft determination: Iberdrola, pp 3-4; CEC and AEC, p 4.

123 For example, AEMO's methodology for its ISP modelling is largely guided by the Cost Benefit Analysis Guidelines and the Forecasting Best Practice Guidelines, which sit outside the rules and are administered by the AER (see clause 5.22.10(a)(1)-(2). Similarly, clause 5.20A.1 describes the content that must be included in AEMO's General power system risk review, but does not set out a specific assessment methodology for how AEMO must identify priority risks.

124 NER, clause 5.20.8(e).

125 Reliability Panel, Review of the System Restart Standard, draft determination, section 4.2, p 38.

We consider that the current consultation and content requirements for the TPSS are appropriate, and already require AEMO to provide substantial information on its plan to manage system security throughout the transition. Further, we note that only one TPSS has been published to date, so we consider it would be helpful to have more data and evidence as to how this process occurred before considering more fulsome changes.

The 2024 TPSS had a compressed timeline for its preparation and publication due to the completion of the *Improving security frameworks* rule in March 2024. For its upcoming 2025 TPSS, AEMO has signalled that it will consolidate the Engineering Roadmap and the annual system security reports into the upcoming 2025 TPSS,[126] and will provide more fulsome discussion and analysis.[127]

The *Improving security frameworks* rule included a requirement for the AEMC to review the transitional services framework and the TPSS by no later than 2031.[128] As part of this review, the Commission will assess the role of the Reliability Panel in providing commentary to AEMO, and whether the TPSS is achieving its purpose under the NER. The Commission considers that more information and editions of the TPSS would be required before considering implementing new, more prescriptive, rules requirements for the TPSS.

On a closely related matter, many submissions considered there is a need for a new governance framework that would provide strategic oversight and independent input into AEMO's future work program, including the TPSS.[129] The Commission's response to these suggestions are detailed in section 4.4.

4.2 The transitional services framework allows AEMO to manage system security in a constantly changing and complex energy transition

4.2.1 Stakeholders suggested that new obligations should be placed on AEMO's use of the transitional services framework

Through the *Improving security frameworks* rule, the Commission introduced the transitional services framework so that AEMO can:

- procure and manage system security services which are not captured through existing frameworks (referred to as Type 1 contracts)
- conduct trials of new technologies or applications of new technologies that allow AEMO to better manage and maintain power system security throughout and beyond the energy transition (referred to as Type 2 contracts).

Both Type 1 and Type 2 contracts mitigate the risk that current and future power system security issues are managed through market interventions or directions. The Commission agrees with stakeholder comments that it is important that AEMO performs the technical work necessary to ensure that it is able to manage and maintain power system security without relying on directions throughout the energy transition.[130] Reliance on directions is inefficient and costly to consumers due to a lack of certainty and transparency for market participants, wear and tear on plant and increased system security risks due to its 'last-time-to-act' nature.

126 AEMO, Engineering Roadmap FY 2026 Priority Actions, pp 19-20.

127 AEMO, submission to the draft determination, pp 4-5.

128 AEMC, *Improving security frameworks*, final determination, section 8.5, p 126; NER, clause 11.168.4 and 11.168.6.

129 Submissions to the draft determination: Australian Energy Council, pp 7-9; CS Energy, p 6; EnergyAustralia, p 2; Snowy Hydro, pp 4-5; Tesla, p 3.

130 Submissions to the draft determination: Australian Energy Council, p 8; CS Energy, p 6; ENA, p 3; Iberdrola, p 1.

In submissions to the draft determination, several stakeholders considered that more obligations should be placed on how AEMO must use the transitional services framework.[131] For example, the Australian Energy Council suggested that AEMO should be required to progress at least one Type 2 contract each year, while Iberdrola suggested that the Reliability Panel could be tasked to set targets for AEMO procurement of Type 2 contracts.[132]

The Commission notes and appreciates the strong stakeholder concern about the fact that AEMO is yet to enter into any Type 2 contracts (as of September 2025). However, the Commission understands that AEMO has gone through a preparatory phase to build up its internal capability and resources to support the prioritisation, procurement, delivery, settlement and cost recovery processes for these innovative commercial contracts.[133] The Commission also understands that AEMO intends to publish 'statements of needs' for Type 2 contracts in the near future, before the December 2025 Transition Plan is released.

We agree with stakeholders that AEMO should strive to make full use of the transitional services framework to increase its engineering knowledge. However, we maintain our view that fixed obligations on AEMO are inefficient and may lead to increased costs to consumers. As previously stated by the Commission:[134]

> We consider that having a fixed, rules-based obligation or target for type 2 contracts could result in inefficient procurement, by putting AEMO in a position where it is required to enter into trials even where they are not valuable to the industry, in order to comply with the rules. These costs would ultimately be borne by consumers.

Furthermore, obligations for AEMO to execute at least a certain number of contracts would give potential transitional service providers a very large amount of negotiating power, with the increased costs and risk associated with such negotiations being borne by consumers.

As part of the development of its TPSS, the Commission encourages AEMO to continue engaging with the Reliability Panel and with industry stakeholders transparently to proactively identify any future potential uses for Type 2 contracts.

4.2.2 Technical knowledge and operational experience from Type 2 trials can inform a real-time market

The Commission expects that Type 2 contracts can greatly assist in expanding AEMO's confidence and knowledge about how to plan, manage and maintain system security throughout the energy transition. In its submission, AEMO noted its support and intent to use Type 2 contracts to support innovation and further technical research, which the Commission welcomes.[135]

As stated in our draft determination, the Commission considers that trials using synthetic inertia in novel ways, or using phasor measurement units (or other plant) to more accurately measure inertia in real-time, would significantly contribute to the management of power system security.[136] Such trials would also provide a suitable foundation for any future design work for the operational procurement of inertia, if the benefits increase in the future.[137]

131 Submissions to the draft determination: Australian Energy Council, pp 7-8, 10; CEC, p 4; CS Energy, p 6; EnergyAustralia, p 5; Iberdrola, p 4.

132 Submissions to the draft determination: Australian Energy Council, pp 7-8; Iberdrola, p 4.

133 See also AEMO, 2024 Transition Plan for System Security, p 50; FY2026 Priority Actions Report, p 19.

134 AEMC, *Improving security frameworks*, final determination, p 70.

135 AEMO, submission to the draft determination, p 5.

136 AEMC, draft determination, p 43.

137 See section 3.8 for more information on the metrics that could indicate an increase in benefits of operational procurement.

In submissions to the draft determination, many stakeholders considered that new obligations, objectives or frameworks were required to ensure that AEMO progresses Type 2 contracts in a manner that would lead to the creation of new markets for system security services.[138] For example, the Australian Energy Council stated:[139]

> AEMO should start developing a systematic technical work program to progress market procurement by leveraging the ISF, especially Type 2 contracts. Accountability for this work program should be enhanced with oversight and progress reporting by the Reliability Panel through terms of reference issued by the AEMC.

As detailed in section 3.9, the Commission considers that system security services should be procured in the manner that is most suitable for the service and the intended security outcome, considering the technical, economic and practical realities of the NEM. Real-time markets are generally preferred, but only where real-time procurement is viable and practical.

The Commission agrees that AEMO should be as transparent as reasonably possible about its technical work program (especially through the Transition Plan for System Security), and that much of AEMO's technical work would improve the implementation of potential future real-time markets for system security services. For example, AEMO's work in developing operational inertia constraints for its enablement tool, as well as its refinement of the quantification method for synthetic inertia, are both vital for the potential future operational procurement of inertia.[140]

However, we do not agree that AEMO should be required to develop real-time market procurement of security services. This is consistent with the Commission's view in the Transitional services update paper and the final determination for the *Improving security frameworks* rule.[141]

As discussed in section 3.9, AEMO's role in managing the technical envelope of the power system is distinct and separate to the choice of procurement mechanism for security services. Any future decision about the creation of new market mechanisms for security services remains the Commission's responsibility.

4.3 TNSP assessment and procurement of non-network options should remain rigorous and clear throughout the transition

Throughout the energy transition, non-network security costs, particularly for system security, are expected to be significant. This is evident from the completed system strength RIT-T processes, but are also expected to play a role in meeting other network needs, such as increasing intra- and inter-regional transfer capacities (in lieu of building more transmission infrastructure), or providing protection schemes (such as the System Integrity Protection Scheme provided by the Waratah Super Battery).[142]

Given the important role that non-network options will play in the transition, the Commission considers that TNSPs should always strive to maximise the transparency of their cost-benefit analysis, modelling assumptions, technical understanding of non-network services, and the rationale for selected the preferred option - subject to commercial sensitivities and consideration of confidential information.[143]

138 Submissions to the draft determination: Australian Energy Council, pp 1, 7-8; CEC, pp 3-4; EnergyAustralia, p 5; CS Energy, pp 5-6.

139 Australian Energy Council, submission to the draft determination, p 8:

140 AEMO, ISF and IPRR Consultation of Constraint Formulation Guidelines; Security Enablement Procedures, p 9; AEMO Research Priorities, p 8.

141 AEMC, Improving security frameworks, transitional services update paper, pp 19-20, 23-24; final determination, pp 121-122, 125.

142 See Waratah Super Battery Enabling Works | Transgrid for more information.

143 AEMC, draft determination, section 4.5.2, pp 43-44.

Given that the *Improving security frameworks* rule improved various aspects of TNSP procurement for system security services, the Commission does not consider that further amendments to the RIT-T process, or new obligations on TNSPs for non-network contracts, is suitable. These improvements include:

- the alignment of the inertia framework with the system strength framework
- promoting more proactive procurement of inertia and the joint consideration of system security costs
- the introduction of an inertia network service specification, which provides minimum technical requirements for synthetic inertia to be approved by AEMO as an eligible inertia service provider
- a new cost recovery arrangement for TNSPs in relation to non-network security providers, to minimise volatility risks for consumers.

We address various stakeholder concerns and suggestions in the sections below, and explain why we do not consider such amendments would contribute to the achievement of the NEO through this rule change process.

4.3.1 Stakeholders raised concerns about unfair competition between non-network options and network assets

Market participants and generation asset owners strongly opposed our draft decision, and considered that relying upon the existing TNSP procurement framework for system strength and inertia would be unfair for non-network options, may not produce timely or cost effective outcomes, or would not be consistent with the NEO.[144] For example, in relation to the existing system strength framework, the Australian Energy Council stated:

> It places TNSPs in the privileged and somewhat conflicted position of having access to, and ultimately making recommendations between, third party system strength offerings and their own direct investments in network assets. These outcomes could be avoided through the creation of a market to procure system strength, rather than reliance on TNSP-led contracting.

The Commission acknowledges these stakeholder concerns, but note that the recently completed system strength RIT-Ts were the first of their kind. This is because they required more complex market and power system modelling to consider security options that have not been previously encountered in RIT-T processes. We expect that TNSPs and other bodies will apply the knowledge and experience gained from conducting and collaborating on the system strength RIT-Ts, when conducting future processes. This should result in a more effective and streamlined process when identifying preferred system security options from a suite of credible options.

However, we consider that the existing regulatory framework protects consumers against a potential bias against non-network options in numerous ways:

- When applying the RIT-T, TNSPs must consider all possible options it could reasonably classify as credible options that can address the identified need, and must take into account all commercially and technically feasible network and non-network options[145]

144 Submissions to the draft determination: AGL, pp 2-3; AEC, pp 1-4; CEC and AEC, p 2; ENGIE, p 2; CS Energy, pp 2, 4-5; Stanwell, p 2; Delta, p 1; EnergyAustralia, pp 2, 4; Origin, p 2; Snowy Hydro, p 4; Stanwell, p 4.

145 NER, clause 5.15.2(a)-(b); AER, RIT-T Application Guidelines, section 3.2, pp 15-21.

- TNSPs cannot consider that the absence of a proponent for a non-network option excludes the option from being considered a credible option; such credible options must be considered in the RIT-T.[146]
- In their project specification consultation reports (PSCRs), TNSPs must describe the technical characteristics of the identified need that a non-network option would be required to deliver,[147] as well as all known credible options that could address the identified need.[148]
- When applying the RIT-T, TNSPs must perform a thorough cost-benefit analysis for all credible options, with regard to at least ten different classes of market benefit.[149] Furthermore, TNSPs must adhere to the RIT-T Application Guidelines, which specifies a detailed methodology for how RIT-T proponents should assess the costs and benefits of each credible option.[150] The methodology must be applied consistently between all credible network and non-network options.[151]
- TNSPs must value the operating and maintenance cost over each credible option's operating life, regardless of whether it is a network or non-network option.[152]
- The RIT-T application guidelines provide several examples of how TNSPs should compare network and non-network costs and benefits against each other.[153]

Where parties consider that a TNSP has not applied the RIT-T in accordance with the NER or with the AER's binding guidance (for example, have not applied a consistent cost-benefit methodology between network and non-network options), then they may lodge a dispute with the AER.[154] If the AER agrees with the dispute, then it may direct the TNSP to amend its project assessment conclusions report (PACR) to comply with the RIT-T.[155]

In our draft determination, we encouraged TNSPs to consider how their existing reporting obligations, particularly through their project assessment draft reports (PADRs) and PACRs, could be used more effectively to explain:

- how the costs and benefits of different options are assessed on a like-for-like basis[156]
- the technical assumptions used to determine feasbility or capability[157]
- the rationale for selecting the preferred option based on system security and cost considerations.[158]

146 NER, clause 5.15.2(d).

147 NER, clause 5.16.4(b)(3); AER, RIT-T Application Guidelines, p 68.

148 NER, clause 5.16.4(b)(6)

149 NER, clause 5.15A.2(b).

150 NER, clause 5.16.2. See also Chapter 3 of the AER's RIT-T Application Guidelines for a comprehensive description of the cost-benefit analysis that TNSPs must undertake, and Chapter 4 for a description of the stakeholder engagement process that should be followed when conducting their RIT-Ts.

151 AER, RIT-T Application Guidelines, p 121. Both network and non-network options are classified as *credible options* in the NER and in the application guidelines, and there is no distinction between them on the application of the RIT-T.

152 RIT-T Application Guidelines, p 26. Where the operating life of a credible option is expected to be longer than the modelling period of the RIT-T, the TNSP must incorporate the operating and maintenance costs for the remaining years of the credible option into the calculation of its terminal value.

153 For example, see section 3.9 and Example 16 of the RIT-T Application Guidelines, pp 51-54.

154 NER, clause 5.16B.

155 NER, clause 5.16B(d)(3)(i) and 5.16B(f)-(g).

156 See sections 3.5 to 3.7 of the AER's RIT-T Application Guidelines for detailed information on how TNSPs should value the costs of each credible option and how they should calculate the classes of market benefits across all credible options.

157 See section 3.2.2 of the AER's RIT-T Application Guidelines for information on how TNSPs must identify all credible options.

158 See sections 3.8, 3.9 and 3.10 of the AER's RIT-T Application Guidelines for how TNSPs should account for reasonable future scenarios and sensitivities, uncertainty and risk, when selecting the preferred option. The preferred option is the credible option that maxmises the net economic benefit across the market, compared to all other credible options (see p 57).

Existing AER guidance states that TNSPs should communicate their assumptions, inputs and decisions as transparently as possible. For example, the AER states that for their PADRs and PSCRs, TNPS should publish:[159]

> Relevant documents that show detailed modelling, inputs and assumptions used for the RIT-T assessment. The RIT-T proponent should undertake best endeavours to address potential confidentiality concerns that might prevent it from making data or modelling information available. For example, the RIT-T proponent could explore whether it can aggregate, anonymise or redact that information, or share it with requesting parties on a confidential basis.

We note that throughout the recently completed system strength RIT-Ts, TNSPs engaged with a significant number of non-network providers to gather better information about credible non-network options that informed their cost-benefit analysis and their PACR.[160] RIT-T preferred portfolio options include a significant number of non-network options, with contractual negotiations with these non-network options having already commenced.

Additionally, to address complex issues associated with the system strength framework, the AER published a guidance note to help TNSPs understand their obligations in applying the RIT-T framework to meet their system strength obligations.[161]

The AER has also published its System Security Network Support Payments Guideline, which describes the factors it will consider when determining whether a forthcoming system security contract with a non-network provider is likely to result in prudent and efficient expenditures.[162] This helps level the playing field between network and non-network solution by improving the efficiency and ability of TNSPs to enter into non-network contracts for system security due to greater cost recovery certainty.[163]

Stakeholder suggestions for changes to the RIT-T or TNSP procurement process

In its submission, Origin suggested that there should be an obligation in the NER for TNSPs to publish key contractual terms and conditions in the early stages of the RIT-T process, to ensure participants have sufficient information to prepare comprehensive submissions to expressions of interest (EOI) processes happening in parallel.[164] The Australian Energy Council suggested that the AER should be required to approve standardised contractual terms for non-network options, with deviations from, or additions to, the standardised terms also being approved by the AER.[165] It also suggested a requirement for all contract templates to be published.[166]

In response to the Commission's call for greater transparency in the application of the RIT-T in our draft determination, the ENA noted that making sensitive information about commercial terms publicly available could risk causing a preferred deal with a non-network provider to fall through due to commercial sensitivities, prior to contract finalisation. TNSPs may then be forced to adopt a higher cost solution, which would not be in the interest of consumers.[167] Transgrid noted that the

159 AER, RIT-T Application Guidelines, pp 70, 72.

160 For example, Powerlink received around 50 confidential proposals from non-network proponents (see p 6 of Powerlink's June 2025 PACR), while Transgrid assessed over 60 non-network solutions from 30 different proponents (see p 36 of Transgrid's July 2025 PACR).

161 AER, Efficient management of system strength framework - Guidance Note - 16 December 2024.

162 AER, System Security Network Support Payment Guideline.

163 Ibid., p 2.

164 Origin, submission to the draft determination, pp 2-3.

165 Australian Energy Council, submission to the draft determination, p 10.

166 Ibid.

167 ENA, submission to the draft determination, p 4.

RIT-T process is separate to a TNSP's procurement process;[168] and the ENA suggested that the RIT-T process is not always the best vehicle to drive transparency in all cases.[169]

Relatedly, in its system strength guidance note, the AER noted that TNSPs should be transparent about the expected contract terms with non-network proponents, allowing them to incorporate this information to provide better information for the RIT-T process.[170]

The Commission generally supports increased transparency in all TNSP procurement processes, but only to the extent where this does not cause perverse outcomes, for example by jeopardising negotiations due to commercial sensitivities relating to plant capabilities or other business information. Generally, it is in a TNSP's best interests to promote competitive tension throughout its procurement process so that it is more likely that the AER will assess its actions as prudent and efficient.

We note that these contracts may need to differ for a wide variety of commercial and technical reasons, so standardisation may not be straightforward. As such, the benefits of potential AER standardisation may be outweighed by the administrative burden and associated costs of potential delays to essential security services that may occur if the AER needs to assess and approve a significant number of deviations to standard contract terms.

However, we do not consider this rule change process to be the appropriate vehicle to introduce new rules regarding broader TNSP procurement processes, or requiring the AER or another party to create standardised terms for system security contracts. We consider that these stakeholder suggestions are out of scope of the proponent's rule change request.

4.3.2 AEMO procedures and AER guidelines should promote consistency across jurisdictions over time

Over time, as TNSPs gain experience in contracting with non-network options for system strength, the Commission expects that procurement processes will become:

- more transparent, as TNSPs gain experience with contracting with a wide range of different non-network providers for system security
- more consistent across different TNSPs, due to AEMO's security enablement procedures mandating minimum requirements that must be included in contract information provided to AEMO for its scheduling function.

Chapter 4 of AEMO's security enablement procedure sets out minimum requirements with respect to:

- the general agreement structure between TNSPs and security service providers
- the fixed and variable service parameters that must be specified to AEMO, such as the minimum enablement duration (i.e. a minimum number of hours that a plant must run for technical or operational reasons), or the activation lead time (i.e. how many hours of notice a plant must receive before receiving an enablement instruction)
- the financial structure of agreements between TNSPs and security service providers, which must make provisions for usage payments, activation payments and energy revenue (however, any of these values may be specified as zero).

168 Transgrid, submission to the draft determination, p 5.

169 ENA, submission to the draft determination, p 4

170 AER, Efficient management of system strength framework - Guidance Note - 16 December 2024, p 24.

These minimum requirements are necessary to allow AEMO to enable contracts at least cost in operational timeframes - see section 6.3.7 of the *Improving security frameworks* final determination.

While TNSPs may develop their own cost structures or innovative commercial arrangements during negotiations with non-network providers, they must ensure that their executed contracts meet the minimum requirements specified by AEMO in its Security Enablement Procedures. This naturally limits the scope of potential cost arrangements that could be devised by TNSPs or providers. Over time, the Commission expects that contractual terms are likely to become more consistent between TNSPs.

4.3.3 These issues could be considered in a potential future network regulation review

We recognise that, despite the current regulatory obligations outlined in section 4.3.1, and the improvements made from recent rules such as the *Improving security frameworks* rule and the *Improving the cost recovery arrangements for Transmission non-network options* rule, many stakeholders consider that non-network options are not fairly considered in the RIT-T process or during procurement processes.

As outlined in our high-level work program for FY2025-26, the Commission has begun scoping and pre-work for a network regulation review. While the Commission is still determining the scope of the review, we expect that the balance of financial incentives between network options and non-network options is likely to be considered.

We consider that some of the stakeholder feedback to our inertia draft determination that relates to barriers to non-network options may be considered through this future review. We encourage stakeholders to engage in that review process so that the Commission may make suitable recommendations in the long-term interest of consumers.

4.4 Existing frameworks and the Reliability Panel provide sufficient accountability for AEMO's work for now

Some stakeholders who submitted to the draft determination considered that a new governance framework should be introduced to improve the accountability of AEMO's technical work program, oversee its Type 2 contracting priorities, and to progress the technical or economic 'unbundling' of system security services.[171] For example, EnergyAustralia considered that the status quo provides AEMO with 'unnecessarily broad, flexible and unvetted strategic and operational control over grid security is eroding industry confidence'.[172]

In addition, these stakeholders envisioned that the Reliability Panel's remit could be expanded to monitor, review or critique AEMO's progress and work. Stakeholders also considered that the Reliability Panel should have a more formal role in the development of AEMO's TPSS,[173] in setting Type 2 procurement targets or objectives,[174] or that the Panel should be required to determine the inertia requirements methodology instead of AEMO.[175]

In response to comments relating to oversight of AEMO's technical work program, the Commission notes that the AEMC, the AER, the Reliability Panel, and industry stakeholders

171 Submissions to the draft determination: AEC, pp 8-9; EnergyAustralia, pp 3-5; Tesla, p 3; CS Energy, p 6; CEC and AEC, p 4; Snowy Hydro, pp 4-5; Delta, p 2.

172 Ibid.

173 Ibid. See also section 4.1 and section 4.2 for discussion relevant to the TPSS or to the transitional services framework

174 Submissions to the draft determination: EnergyAustralia, p 5; AEC, pp 7-10.

175 CS Energy, submission to the draft determination, p 2.

regularly provide information, feedback and collaborate with AEMO through its many consultation processes, working and advisory groups, and other committees. Additionally, the NER already confers several formal security-related functions onto the Reliability Panel (see section 4.4.1 below).

We consider that these functions already provide a suitable level of accountability and oversight of AEMO's technical work. Coupled with the minimum consultation requirements that exist for many important AEMO reports (such as the ISP, the GPSRR, the TPSS, the Inertia and System Strength Requirements Methodology)[176] the Commission considers that there are suitable avenues where any stakeholder (or private individual) can provide their comments, feedback and questions to AEMO - and where AEMO's response must be made publicly available.

In response to stakeholder comments about progressing unbundling of security services, as discussed in section 3.9, we do not consider it is appropriate at the current time to place an obligation that requires AEMO to develop real-time markets ahead of a clear benefit for consumers eventuating, or for the Reliability Panel to ensure that such an objective is being adequately met through AEMO's work. The choice of procurement mechanism for a particular security service is separate to both the day-to-day and long-term management of system security - with the latter being one of AEMO's statutory functions.

Additionally, much of the technical work that AEMO is progressing would lay the foundation for a potential future real-time inertia market, if it becomes beneficial (see section 3.7.1).

4.4.1 The Reliability Panel has several security-related functions that could improve AEMO accountability

We do not agree that codifying a new strategic advisory function for system security for the Reliability Panel is necessary. This is because the Panel's purpose and role under the NEL is to:[177]

> monitor, review and report on, in accordance with the Rules, the safety, security and reliability of the national electricity system.

In addition, the NER already allows the Reliability Panel to perform a wide variety of security-related functions, such as:

- determine the *system restart standard*, on the advice of AEMO[178]
- determine the power system security standards, which are standards that AEMO must adhere to, such as (but not limited to) the *frequency operating standard*[179]
- develop and publish principles and guidelines that determine how AEMO should maintain power system security while taking into account the costs and benefits to the extent practicable[180]
- determine guidelines for AEMO's conduct of its annual GPSRR[181]
- determine guidelines governing the exercise of directions by AEMO[182]

176 For the ISP, the NER requires AEMO to publish a very detailed and lengthy consultation process, which involves the consultation on and publication of an *ISP timetable*, an *Inputs, Assumptions and Scenarios Report*, a draft ISP and a final ISP, as well as consultation with a Consumer Panel - see NER, clause 5.22. For the GPSRR, the NER requires AEMO to thoroughly consult with TNSPs and DNSPs, and prepare a draft and final GPSRR which includes AEMO's conclusions in response to any submissions received - see NER, clauses 5.20A.1 to 5.20A.3.

177 NEL, s 38(2)(a).

178 NER, clause 8.8.1(a)(1A).

179 NER, clause 8.8.1(a)(2).

180 NER, clause 8.8.1(a)(2A).

181 NER, clause 8.8.1(a)(2D).

182 NER, clause 8.8.1(a)(3).

- report to the AEMC and jurisdictions on the above matters (or on any other matters the Reliability Panel) considers necessary, and make recommendation on market changes or changes to the NER[183]
- monitor, review and publish reports on the system standards and access standards, and whether they should be amended or removed[184]
- upon request by a party, determine whether an existing Australian or international standard is to be adopted as an acceptable plant standard for a particular class of plant[185]
- as discussed in section 4.1.2, provide written commentary to AEMO on its TPSS.[186]

For a list of reviews, guidelines and standards published by the Reliability Panel, see Responsibilities and obligations | AEMC.

The Commission considers these existing Reliability Panel functions to be comprehensive and meaningful in providing adequate monitoring of AEMO's security functions. By virtue of the Panel's diverse membership and varied expertise, the Panel can synthesise industry advice to AEMO on its security functions, thereby providing accountability.

We consider that stakeholder suggestions to create new formal roles for the Reliability Panel are likely to be duplicative with the Panel's NER functions, and would not be likely to provide meaningful benefits to consumers.

4.4.2 We do not consider the Reliability Panel should determine the inertia requirements methodology

The Commission has considered the AEC's and CS Energy's suggestion that, potentially as part of a new governance framework, the Reliability Panel should determine the inertia requirements methodology, which sets out minimum inertia levels required for secure operation.[187]

We consider that the existing framework is appropriate, and reflects that under the NER, the Reliability Panel (on the advice of AEMO) determines power system security standards[188] while AEMO develops the detailed methodology for determining the secure technical envelope that adheres to those standards.[189]

In the case of inertia, the Reliability Panel determines the *frequency operating standard* (FOS), which sets out the maximum allowed RoCoF that the power system should experience following a contingency event (currently, 1 Hz/s on the mainland and 3 Hz/s for Tasmania).[190] The inertia requirements methodology then sets out AEMO's methodology for determining:

- the set of all relevant credible contingency events that will allow it to determine inertia levels
- each inertia level such that the *frequency operating standard* is adhered to
- related technical matters, such as the relationship between inertia and fast frequency response, and how AEMO determines whether regions are at credible risk of islanding.[191]

183 NER, clause 8.8.1(a)(5).
184 NER, clause 8.8.1(a)(6)-(7).
185 NER, clause 8.8.1(a)(3).
186 NER, clause 8.8.1(a)(10).
187 Submissions to the draft determination: AEC, p 7; CS Energy, pp 2, 5.
188 NER, clause 8.8.1(a)(2)).
189 NER clause 4.2.4, 4.2.5 and 4.2.6 requires AEMO to maintain a secure operating state and determine and use the technical envelope required for secure operation in accordance with any power system security standards or guidelines published by the Reliability Panel.
190 Reliability Panel, Frequency operating standard - in effect 9 October 2023, p 4.
191 See NER clause 5.20.4 for more information, as well as AEMO's current Inertia Requirements Methodology.

In developing or amending the methodology, AEMO must follow the rules consultation procedure.[192]

In the Commission's view, the methodology can only be determined by AEMO, as AEMO is the only party with the expertise to determine the technical envelope and the set of all contingency events needed to determine inertia requirements that adhere to the FOS. In managing the technical envelope, we understand that AEMO is also developing operational inertia constraints for the enablement of security contracts that should be publicly available to view in its market management system.[193]

As an analogy, while the FOS determines acceptable frequency bands (such as the normal operating frequency band), AEMO is the party that determines the methodology for how it registers FCAS providers and procures FCAS in real-time, to adhere to the FOS. It would also be inappropriate for a different party than AEMO to manage FCAS registration and constraint development.

For these reasons, the Commission has not adopted the suggestion for the Reliability Panel to determine the inertia requirements methodology.

192 NER, clause 5.20.4(c).

193 See section 3.6 for more information.

A Rule making process

A standard rule change request includes the following stages:

- A rule change request is submitted to the Commission by a proponent.
- The Commission initiates the rule change process by publishing a consultation paper and inviting submissions from stakeholders.
- Stakeholders provide feedback through submissions and other engagement with the AEMC project team.
- The Commission considers the issues raised and publishes a draft rule determination and draft rule (if applicable).
- Stakeholders have the opportunity to comment on the draft through a second round of consultation.
- The Commission publishes a final determination and final rule (if applicable), informed by stakeholder input and further analysis.

You can find more information on the rule change process on our website.[194]

A.1 The AEC proposed a rule to establish operational procurement of inertia

The Australian Energy Council (AEC) submitted a rule change request proposing the introduction of an ancillary service spot market for inertia in the NEM. The proposed rule aimed to establish inertia as a standalone market-based service, procured and dispatched in real time, to better support system security and efficiency as the generation mix transitions.

Under the AEC's proposal, a dedicated spot market would be created in which inertia could be offered, priced, and dispatched separately from other services. This market would operate with a common clearing price and a price floor of zero, and would enable AEMO to procure inertia from synchronous generators, including those operating at zero megawatt output, as well as grid-forming inverter-based resources assessed by AEMO as capable of providing inertia-like performance.

The proposed framework would provide real-time price signals to reflect system-wide inertia needs, supporting transparent valuation and enabling more efficient procurement. Inertia would also be co-optimised with existing FCAS markets in the NEM Dispatch Engine (NEMDE), allowing total system costs to be minimised across essential system services.

The AEC argued that the existing framework, which relies on long-term TNSP contracting and uncompensated provision from synchronous generators, may not remain sufficient under evolving system conditions. The proposal was intended to address concerns around inflexibility, lack of transparency, and over-contracted solutions by enabling more dynamic, technology-neutral, and cost-reflective procurement arrangements.

A.2 The process to date

On 2 March 2023, the Commission initiated the rule change request submitted by the Australian Energy Council (AEC) proposing a spot market for inertia. A consultation paper was published to

194 See our website for more information on the rule change process: https://www.aemc.gov.au/our-work/changing-energy-rules

seek stakeholder feedback on the proposal and related issues. Submissions closed on 31 March 2023, with 25 submissions received.

Following this consultation, the Commission prioritised finalising the *Improving System Security Frameworks* (ISF) rule change before progressing further on the operational procurement of inertia. The ISF final determination was published on 28 March 2024. These reforms introduced a NEM-wide minimum inertia requirement, enhanced procurement frameworks, and a framework for Type 2 system security contracts.

Building on the ISF reforms, the Commission published the ERC0339 Directions Paper on 12 December 2024. This paper set out preliminary views on the operational procurement of inertia and sought stakeholder feedback on whether a new mechanism should be implemented now or deferred in favour of improvements to existing frameworks. The Commission received 20 submissions in response to the Directions Paper.

On 26 June 2025, the Commission published a draft rule determination to make no rule. The Commission received 17 submissions on the draft rule determination. Issues raised in submissions are discussed and responded to throughout this final rule determination. A summary of other issues raised in submissions and the Commission's response to each issue is contained in appendix C.

B Legal requirements to make a rule

This appendix sets out the relevant legal requirements under the NEL for the Commission to make a final rule determination.

B.1 Final rule determination

In accordance with section 102 of the NEL, the Commission has not made a final rule in relation to the rule proposed by the Australian Energy Council.

The Commission's reasons for making this final rule determination are set out in chapters 3 and 4.

B.2 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the final determination
- the rule change request
- submissions received during first round consultation, and to our directions paper and draft determination
- the Commission's analysis as to the ways in which the final determination will or is likely to contribute to the achievement of the NEO

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[195]

195 Under s. 33 of the NEL and s. 73 of the NGL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy.

C Summary of other issues raised in submissions

Table C.1: Summary of other issues raised in submissions to the draft determination

Stakeholder	Issue	Response
CEC and AEC, p 1	Considers draft decision is inconsistent with AEMC's NEL market development function.	The Commission's rationale for not implementing a new real-time inertia market is explained in section 2.3 and throughout chapter 3.
CEC and AEC, p 2	Considers there is a lack of a technology-agnostic framework to assess and deliver system security services	The existing inertia framework allows both synchronous and asynchronous sources to contribute to meeting minimum requirements - see AEMO's Inertia Requirements Methodology, Appendix A.
CEC and AEC, p 2	Considers that an inertia framework should include Lack of Inertia 1 and 2 thresholds to provide market signals.	AEMO is developing operational inertia constraints to manage inertia in operational timeframes through enablement. These will be available for market participants to monitor through AEMO's MMS - see AEMO | ISF and IPRR Consultation of Constraint Formulation Guidelines.
CEC and AEC, p 3	Considers that AEMO should be required to develop and justify criteria to demonstrate where the lowest cost Type 1 or Type 2 tender was not in the best interest of the consumer.	AEMO's Transitional services guideline has detail on when AEMO may select services that are not lowest cost, in isolation - see pp 10-11 of its guideline.
AEC, p 10	Considers that the AEMC should articulate how it will undertake a review of the transitional services framework and assess progress.	The Commission has set out how it intends to review the transitional services framework in its final determination for the *Improving security frameworks* rule - see pp 126-127.
Iberdrola, p 4	Considers that AEMO should have an obligation to report in the Electricity Statement of Opportunities (ESOO) the volume of required security services.	The Commission considers that the obligations for the TPSS at NER clause 5.20.8(c)(1)-(8) already require AEMO to report on how it intends to manage system security throughout the transition. Required and expected volumes of security services, such as inertia, system strength and NSCAS, are outlined in their respective annual reports (which will be consolidated with the TPSS for 2025).

Stakeholder	Issue	Response
Iberdrola, p 4	Considers that TNSPs and AEMO should have an obligation to procure sufficient inertia to be capable of zero emissions electricity generation by 2030.	The Commission considers that inertia is not the only system security need that may prevent AEMO from being capable of dispatching zero emissions electricity generation, and so such an obligation would be unreasonable. As explained in section 3.4, we consider that minimum fault current is a more urgent requirement that could prevent zero emissions dispatch.

D Inertia requirements and regional inertia supply and demand graphs

D.1 The 2024 Inertia Report sets out the binding inertia requirements for each region

AEMO's most recent 2024 Inertia Report applied the new Inertia Requirements Methodology, which now includes the determination of a system-wide inertia level, as well as an inertia sub-network allocation for each mainland NEM region. AEMO has determined the following inertia requirements from 2 December 2024 to 1 December 2034 - see Table D.1 below.

Table D.1: Summary of mainland inertia requirements from 2 December 2024 to 1 December 2034

Region	Inertia sub-network allocation (MWs)	Secure inertia level (MWs)
New South Wales	**9,600**	12,500
Queensland	10,500	**13,700**[A]
Victoria	**11,800**	15,400
South Australia	**4,300**	5,600[B]

Source: Adapted from AEMO, 2024 Inertia Report, Table 1 on p 3.

Note: The amount of inertia that each TNSP must make available by 2 December 2027 is depicted in **bold**, and depends upon whether AEMO considers there is a credible risk of islanding for that region. See clause 5.20B.2 and 5.20B.4 of the NER.

Note: [A] AEMO considers Queensland is likely to island until both QNI Connect is commissioned and a control scheme exists to manage the non-credible loss of QNI and QNI Connect, which is only expected to be completed in 2033 or later. Therefore, Powerlink must ensure that the secure inertia level is available, pursuant to clause 5.20B.4(b) of the NER (in addition to its requirements under 5.20B.4(a1) and (a2) in respect of the inertia sub-network allocation).

Note: [B] AEMO does not consider that South Australia to be sufficiently likely to island following the expected commissioning of Project Energy Connect (PEC) Stage 2 and necessary protection schemes are in place to manage the non-credible loss of either PEC itself or the Heywood interconnector. As PEC Stage 2 is expected to be commissioned before 2 December 2027, ElectraNet must ensure that the inertia sub-network allocation level is available by that date, pursuant to clause 5.20B.4(a1) and (a2) of the NER.

For the purpose of determining an aggregate requirement for Figure 3.3, the sum of the 'binding' requirements (depicted in bold in Table D.1) was used, subject to the following assumptions:

- The aggregate requirement uses the secure inertia level for South Australia, but only until the beginning of 2028, when PEC Stage 2 is expected to be fully operational. Thereafter, the inertia sub-network allocation for South Australia is used.
- The aggregate requirement uses the secure inertia level for Queensland, but only until the beginning of 2036, by which point QNI Connect is expected to be commissioned. Although QNI Connect is expected to be commissioned by June 2033, we have assumed that the credible risk of islanding for Queensland does not change through the 10-year forecast in the 2024 Inertia Report (that is, until 1 December 2034).[196] This is a conservative estimate for when inertia requirements may decrease due to Queensland no longer having a credible risk of islanding, and provides leeway for delays to QNI Connect.

D.2 Regional inertia supply and demand graphs show that inertia shortfalls are not expected in the short- and medium-term

Figure 3.3 provides a summarised aggregate view of expected mainland NEM inertia requirements. However, it is important to recognise that there is no mainland-wide 'minimum inertia requirement' - instead, there are different regional inertia requirements that must be met by

196 Powerlink, Preparatory Activities - QNI Connect, p 16.

each applicable TNSP. Therefore, it is more useful to look at the expected inertia supply and demand at a regional level. These have been presented below at Figure D.1, Figure D.2, Figure D.3 and Figure D.4.

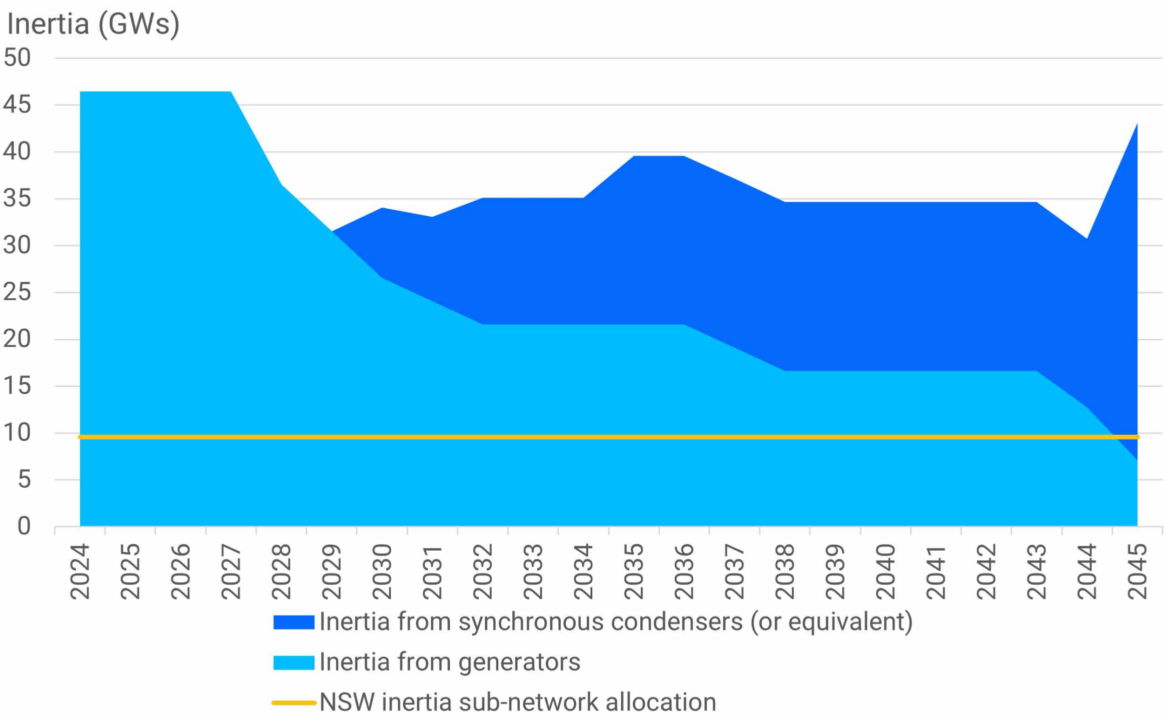
The following assumptions about inertia supply have been made:

- Future synchronous condensers are assumed to deliver about 1500 MWs (see Transgrid PACR, p 33), noting that it is expected that TNSPs will add flywheels to their synchronous condensers when meeting system strength obligations (see section 3.4.2).
- From each TNSP PACR (or PADR, in the case of ElectraNet), the preferred portfolio option was selected.
- Any inertia that may be provided from future GFM BESS that may be contracted to meet stable voltage waveform requirements was not included in order to present a more conservative view of future inertia supply.
- If an investment is listed to be commissioned for a particular financial year in each PACR (e.g. for 2027/28), then it was assumed that it would only be delivered in time for the next calendar year (e.g. 2029). That is, we have accounted for any delays that last between 6 and 18 months.
- In each graph, the 'inertia from generators' series was calculated by inspecting the relevant Generic Constraint Right Hand Side Equations used in pre-dispatch, and extracting the amount of inertia that is provided by each generating unit.[197] This means that it includes the inertia from already-installed synchronous condensers, such as the Davenport and Robertstown synchronous condensers in South Australia, or the synchronous condensers supporting the Murra Warra Wind Farm or the Kiamal Solar Farm in Victoria.
- The retirement dates for existing generators were taken from AEMO's 2024 ISP and its Generating Unit Expected Closure Year spreadsheet from April 2025.[198] Where retirement dates conflict, the earliest retirement date was chosen to reflect a 'worst-case' scenario for inertia supply. An exception to this is the closure date for the Osborne Power Station, which is now reasonably expected to close in 2027.

197 The Equation IDs that were referenced are: X-QLD_INERT_PD, X-NSW_INERT_PD, X-VIC_INERT_PD and X-SA_INERT_PD.

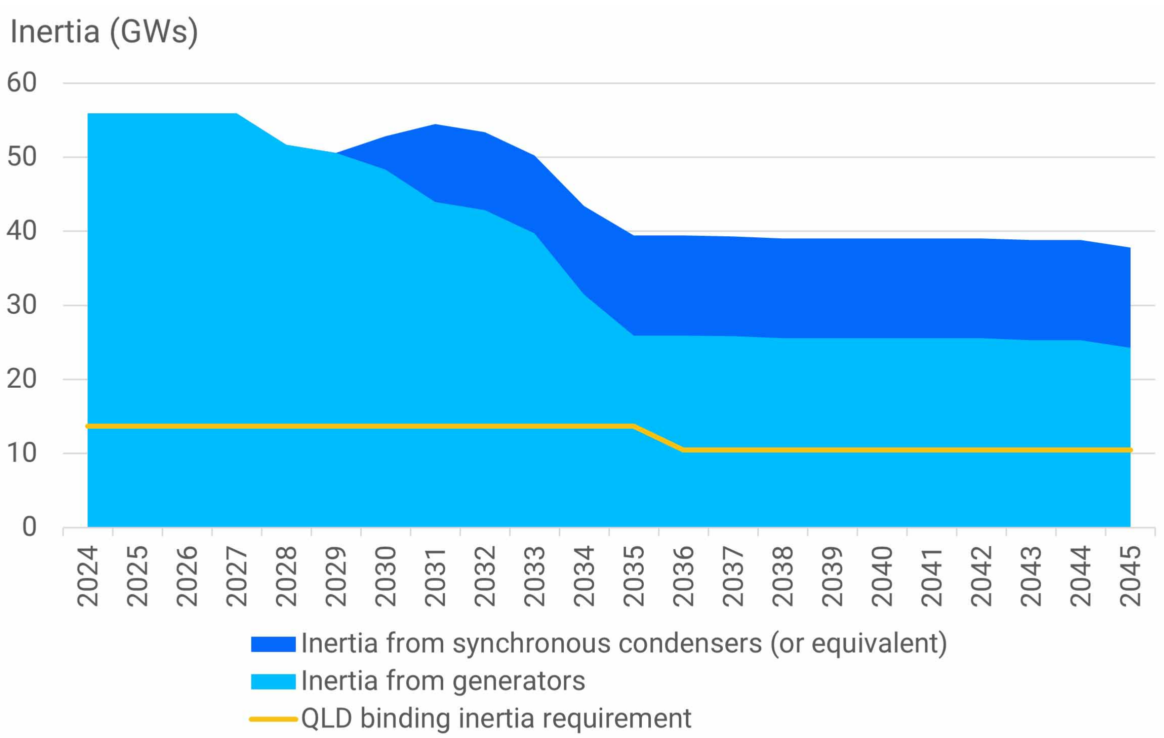
198 See AEMO's generation information page.

Figure D.1: Expected inertia supply in New South Wales



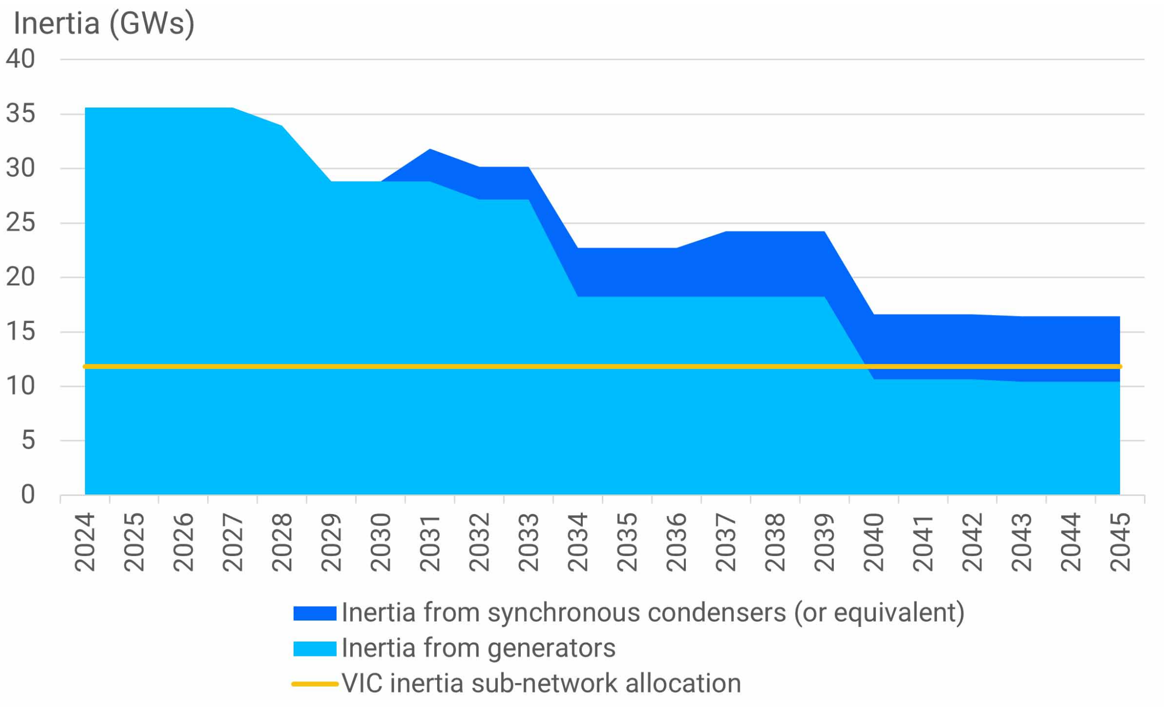
Source: Transgrid, Meeting system strength requirements in NSW PACR.

Figure D.2: Expected inertia supply in Queensland



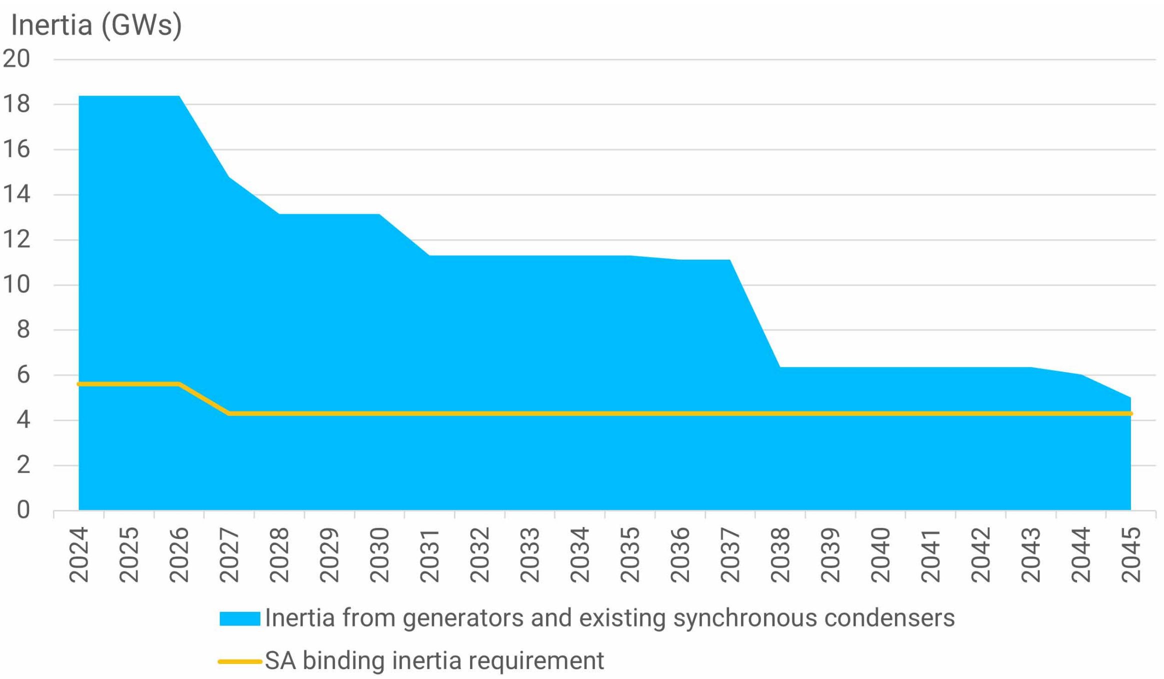
Source: Powerlink, Addressing System Strength Requirements from Dec 2025 - PACR - June 2025.

Figure D.3: Expected inertia supply in Victoria



Source: AEMO Vic Planning, [Victorian System Strength Requirement RIT-T Project Assessment Conclusions Report](#).

Figure D.4: Expected inertia supply in South Australia



Source: Electranet, [Meeting System Strength Requirements in SA PADR](#).

Note: ElectraNet considers that it will meet its system strength obligations without any new investments. However, it noted that it may consider adding clutches to new synchronous generators in the future, as insurance against having insufficient system strength, if system conditions change. Therefore, the graph above does not show any future synchronous condenser investment or equivalent.

Abbreviations and defined terms

AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
CEC	Clean Energy Council
Commission	See AEMC
ENA	Energy Networks Australia
FCAS	Frequency control ancillary service
FFR	Fast frequency response
GFM	Grid-forming
GPSRR	General power system risk review
Hz	Hertz - cycles per second
IBR	Inverter based resource
ISF	Improving security frameworks for the energy transition Rule 2024
ISP	Integrated System Plan
MMS	Market Management System
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NSCAS	Network support and control ancillary service
PACR	Project Assessment Conclusions Report (in relation to a RIT-T)
PADR	Project Assessment Draft Report (in relation to a RIT-T)
Panel	Reliability Panel
PEC	Project Energy Connect
PSCR	Project Specification Consultation Report (in relation to a RIT-T)
Proponent	The individual / organisation who submitted the rule change request to the Commission
QNI	Queensland-New South Wales Interconnector
RASR	Reliability and Security Report
REZ	Renewable Energy Zone
RIT-T	Regulatory investment test for transmission
RoCoF	Rate of change of frequency
SSSP	System strength service provider
TNSP	Transmission network service provider
TPSS	Transition Plan for System Security