AEMC

AUSTRALIAN ENERGY MARKET COMMISSION

RULE

Directions Paper

National Electricity Amendment (Efficient provision of inertia) Rule 2025

Proponent

Australian Energy Council

12 December 2024

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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 all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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Summary

This Directions Paper progresses the Commission's consideration of operational procurement of inertia

1 The National Electricity Market (NEM) is at the forefront of the energy transition globally. It has one of the highest penetrations of inverter-based resources (such as wind, solar and batteries) worldwide, which are rapidly displacing synchronous generation (coal and gas). Historically, the NEM's system security was supported by inertia provided naturally by synchronous generators. As these generators retire, the NEM faces a steady decline in inertia, raising challenges for maintaining a secure and stable system operation.

2 As the power system continues to transition, we are gaining new insights into inertia, emerging technologies, and their roles in maintaining system security. Inertia is one of many interrelated services essential for system stability, closely linked with other system security needs such as frequency control and system strength. It is within this evolving and interconnected context that the Commission is considering this rule change, recognising the importance of a coordinated approach to support the NEM's transformation.

3 In response to these emerging challenges, the Australian Energy Council (AEC) submitted a rule change request to the Australian Energy Market Commission (AEMC or the Commission) to explore an inertia spot market. This proposal suggests a real-time market for inertia that could provide price signals, incentivising efficient provision of inertia alongside other system services and potentially lowering total system costs.

4 To assess this, the Commission published an initial consultation paper on the inertia rule change in March 2023. However, the Commission subsequently decided to prioritise the completion of the Improving Security Frameworks (ISF) rule change, which aimed to strengthen the inertia framework within the planning timeframe. The ISF rule change, completed in March 2024, introduced various enhancements to the inertia framework, such as the mainland inertia floor and alignment of investment frameworks with system strength.

5 The Commission's consideration of operational procurement options in this paper builds on the ISF rule change. The ISF rule change did not and does not preclude consideration of operational procurement (although it did consider how contracts procured in the planning timeframe could be enabled in real-time). Instead, it provided a foundation for further exploring real-time procurement mechanisms to complement long-term arrangements.

As a first step, the Commission is focusing on assessing the economic case for operational procurement of inertia

6 This Directions Paper focuses on assessing the economic case for operational procurement as a first step, recognising the need for further technical analysis to address unresolved questions about implementation and feasibility. We also recognise that there is a link between the operational and investment timeframes that needs to be considered as well.

7 A key reason for prioritising economic analysis is to evaluate whether operational procurement has sufficient potential benefits to justify further exploration of implementation and feasibility. This approach enables the Commission to ensure that its efforts are targeted and aligned with the National Electricity Objective (NEO). The economic analysis examines whether inertia possesses the characteristics necessary for operational procurement and considers potential cost savings and efficiency gains from such mechanisms.

8 The Commission acknowledges that additional technical work is required to resolve critical questions about operational procurement. AEMO, as the system operator, is best placed to undertake this work, given its expertise and ongoing role in managing system security.

9 AEMO has made progress in understanding the system's needs, including studies such as the Vysus Group analysis and collaboration with TasNetworks. It has also developed resources like the Voluntary Specification for Grid-Forming Inverters and has plans to conduct trials and stability studies.

10 However, more detailed analysis is needed to determine the locational versus global nature of inertia requirements, the integration of grid-forming technologies, and the operational challenges of dynamically co-optimising inertia with other system services. To some extent, the work required would also depend on the preferred procurement design for inertia.

11 The findings from this assessment, along with stakeholder feedback, will help determine whether further investigation into the technical feasibility and implementation of operational procurement is warranted as part of the next stage of the project.

12 In preparing this Directions Paper, the Commission engaged Houston Kemp to develop a two-stage economic test to evaluate operational procurement options. This test considers both the **minimum inertia** required to maintain system security and **additional inertia**, which could reduce reliance on fast-frequency response services and lower overall system costs. While the preliminary findings indicate potential benefits from operational procurement, the analysis highlights the importance of resolving technical uncertainties before any decisions can be made.

13 This Directions Paper seeks stakeholder feedback on the economic assessment methodology, the findings, and the implications for operational procurement. Stakeholder input will play a vital role in shaping the Commission's consideration of this rule change.

14 Written submissions to this Directions Paper must be lodged with the Commission by **5 pm, 5 February 2025**.

Inertia is a fundamental system need

15 Inertia inherently and instantaneously responds to frequency disturbances, limits the rate of change of frequency (RoCoF) following large disturbances, and stabilises oscillations between plants and sub-regions of the system. These functions are essential for keeping system frequency and voltage within secure limits during normal operation and following contingency events.

16 Inertia can be provided by synchronous generators and condensers, as well as grid-forming inverters capable of emulating inertial responses:

- Synchronous inertia, inherent to coal, gas, and hydro plants and synchronous condensers (syncons), depends on the rotating mass of these machines.
- Grid-forming inverters, in contrast, provide synthetic inertia by responding to frequency changes but require headroom or footroom in their operations to deliver effective inertial responses

17 The Commission distinguishes between **minimum inertia** requirements, which is the amount and distribution of inertia required for secure system operation, and **additional inertia** , which is any additional inertia above the minimum inertia requirements that reduces dispatch costs by decreasing FCAS requirements or alleviating binding constraints. Specifically,

- the minimum inertia requirement varies in real time, depending on system conditions and the size of credible contingencies.

- additional inertia depends on market participant bids and dispatch outcomes, and, in some instances, may be zero.

18 Currently, there is no mechanism to explicitly calculate or meet additional inertia demand, and determining its benefits is a key objective of this Directions Paper.

19 Under the current framework, AEMO annually determines and publishes 10-year minimum inertia requirements. These requirements specify system-wide levels for interconnected operation and satisfactory and secure levels for regions at risk of islanding. Transmission Network Service Providers (TNSPs) are obligated to ensure these requirements are met through investments in synchronous condensers or long-term contracts with generators and integrated resource providers. TNSPs may also reduce their obligations by contracting fast frequency response (FFR) services to offset some inertia needs.

20 AEMO will enable TNSP contracts in real time to ensure minimum inertia demand is met at the least cost. AEMO dynamically enables TNSP contracts as system conditions evolve. This involves identifying the optimal combination of available resources and activating contracts of up to 12 hours ahead of dispatch to address forecast shortfalls. TNSPs must provide AEMO with detailed information about their contracts, including technical specifications and cost structures, to support this optimisation process.

21 By 31 August 2025, AEMO is required to publish Security Enablement Procedures that detail how real-time minimum inertia requirements are determined and met. These procedures will specify adjustments for interconnected and islanded operation, enabling AEMO to dynamically coordinate contracts no more than 12 hours ahead of dispatch. TNSPs are required to provide AEMO with detailed contract information to facilitate the least-cost enablement of resources.

22 This framework ensures that minimum inertia demand is always met, assuming sufficient compliance by participants and no unplanned outages. However, contract enablement does not address additional inertia demand, which remains unmet under the current framework.

23 The Commission's work focuses on exploring options to meet additional inertia demand, which may offer opportunities to further optimise system efficiency and reduce costs.

To assess operational procurement of inertia, we analysed inertia supply and demand and used a two-stage economic test

24 The Commission engaged HoustonKemp to conduct a detailed analysis of inertia's supply and demand characteristics and to develop a two-stage economic test to assess whether operational procurement could deliver material benefits compared to the existing framework. The assessment also incorporated feedback from a Technical Working Group (TWG) formed for this project which includes AEMO, ensuring robustness in the methodology, assumptions, and practical considerations.

25 HoustonKemp's analysis relied on AEMO publications, inertia methodologies, and cost estimates for synchronous and asynchronous plant. The analysis considered various scenarios, including potential delays in synchronous condenser investments, to provide a comprehensive understanding of inertia supply and demand. This formed the basis for the two-stage economic test.

26 The first stage examined whether minimum and additional inertia exhibit characteristics that align with efficient operational procurement mechanisms, such as a spot market. Factors considered included:

- the stability of service attributes,
- the potential for efficiency gains,
- the economic impacts of imbalances,
- investment certainty requirements, and
- competition levels.

27 Minimum inertia was determined to be unsuitable for operational procurement due to its critical role in system security and high costs of undersupply. However, additional inertia was found to align better with operational procurement principles, warranting further analysis in Stage 2.

28 The second stage quantified the potential benefits of operational procurement for additional inertia, focusing on avoided costs within the existing framework. Key benefits included:

- reduced fast frequency response costs in the 1-second FCAS markets,
- lower costs by alleviating constraints on generators and interconnectors, and
- reduced reliance on AEMO's directions to synchronous generators during shortfalls.

29 These benefits were assessed alongside the costs of implementing a spot market for inertia, including design, administration, and participant costs. The estimates were expressed in 2024-dollar terms and discounted at 7%.

30 The Commission and HoustonKemp adopted simplifying assumptions reflecting a scenario to maximise the potential benefits of operational procurement. Simplifying assumptions, such as treating inertia as a global or regional requirement and focusing on marginal costs, were used to create an illustrative scenario for operational procurement for analysis. This approach aimed to determine whether operational procurement could demonstrate clear and significant benefits, providing a foundation for exploring market design options.

Inertia demand and supply characteristics underpin the economic analysis

31 The Commission has examined how the supply and demand for inertia in the NEM will evolve as the energy system continues to transition. Inertia is critical for maintaining system stability, and understanding future supply and demand dynamics is essential to developing effective procurement options.

32 We estimate that the demand for inertia will decline as in inverter based resources replace traditional synchronous generators, given their superior ability to withstand high RoCoF. However, future large-scale renewable projects, such as offshore wind farms or renewable energy zones, may increase inertia demand depending on how they connect to the network and the need to manage larger contingencies. These effects could be mitigated by special protection schemes or changes to contingency classifications. Using AEMO's inertia reports and the Integrated System Plan, we forecast minimum inertia demand to decline significantly as coal and gas generators retire, although these estimates are conservative and may overstate real-time demand.

33 The supply of inertia will also shift as synchronous generators retire. Synchronous condensers, including those equipped with flywheels, will play a growing role in meeting inertia requirements. Under the updated system strength and inertia frameworks, TNSPs are preparing to install approximately 36 new synchronous condensers over the next nine years to meet their obligations. These investments are expected to provide a stable source of inertia, although uncertainties remain around timelines, procurement choices, and the technical specifications of these condensers.

34 We also identify emerging technologies that could diversify inertia supply. Synthetic inertia from

inverter based resources, such as battery energy storage systems, offers significant potential, and due to advancements in storage technology, costs are projected to decrease substantially by 2030.

35 Load-side inertia, provided by industrial synchronous motors and distributed resources like household batteries, is another key opportunity. However, the future contribution of load-side inertia remains uncertain due to declining synchronous motor usage and challenges in measuring real-time inertia contributions from loads.

36 The Commission highlights the varying costs associated with different sources of inertia. Synchronous condensers with flywheels provide reliable inertia but require substantial upfront investment. Synthetic inertia from inverter based resources is becoming more competitive, with declining costs likely to increase its role in the NEM. Load-side inertia offers flexibility but is difficult to integrate into procurement models due to measurement challenges.

37 To support the assessment of effective operational procurement options, the Commission seeks stakeholder feedback on future supply and cost estimates for inertia. This includes input on the fixed and variable costs of emerging technologies, expected deployment timelines, and any additional insights to refine these projections.

The Commission's findings from the two-step economic analysis suggest there is an economic case for further considering operational procurement for additional inertia

38 The Commission applied a two-stage economic test to assess the suitability of operational procurement for both minimum and additional inertia in the NEM. The findings highlight the distinct economic characteristics of minimum and additional inertia, demonstrating that while long-term procurement remains the best approach for minimum inertia, additional inertia shows potential for operational procurement under certain conditions.

39 We determined that minimum inertia has some economic characteristics that align with operational procurement. However, the high risks and costs of undersupplying minimum inertia make it unsuitable for operational procurement as a primary mechanism. Minimum inertia is critical for system security, ensuring the NEM can withstand large disturbances without resorting to under-frequency load shedding or risking system-wide blackouts. For these reasons, we reaffirm that long-term procurement frameworks, which provide investment certainty, are currently the most appropriate mechanism to secure minimum inertia.

40 Our analysis shows that additional inertia has economic characteristics that make it more suitable for operational procurement. Unlike minimum inertia, an undersupply of additional inertia does not pose immediate system security risks. Instead, additional inertia provides benefits by reducing frequency management costs and improving dispatch efficiency. Operational procurement for additional inertia could co-optimise inertia with fast frequency response, reducing the costs of procuring these services.

41 HoustonKemp's modelling estimated potential benefits from these efficiencies ranging from up to $7.7 million in 2024 to between $0.9 and $30 million by 2033. In addition, operational procurement of additional inertia could alleviate inertia constraints in Tasmania and South Australia, enabling more efficient generation dispatch and reducing overall system costs.

42 HoustonKemp also identified potential benefits from using operational procurement to address shortfalls in minimum inertia in real-time. This approach could supplement long-term contracts, providing a cost-effective alternative to directing synchronous generators online to meet minimum

levels. To capture the illustrative scenario for operational procurement and ensure all potential benefits were accounted for, the analysis included avoided costs per direction, estimated at $1.8 million. Further, annual benefits from alleviating contingency constraints were estimated between $0.7 million and $7.2 million, demonstrating the potential value of operational procurement in reducing system costs.

43 While operational procurement is not recommended as a primary mechanism for minimum inertia, these findings suggest it could complement existing frameworks to reduce costs in specific circumstances.

44 The Commission notes that the suitability of operational procurement depends on system conditions and market dynamics. For additional inertia, the Commission's economic test showed that it could support dynamic optimisation of inertia and FCAS, leveraging market mechanisms to reduce overall system costs. However, further analysis is needed to refine implementation details and ensure the approach aligns with broader system objectives.

45 Stakeholder feedback is essential to guide the next steps. The Commission seeks insights on the findings of this analysis, including the practicalities of operational procurement for additional inertia and its potential to complement the long-term procurement framework.

There are important implementation considerations to operationally procuring inertia

46 The Commission has explored key implementation considerations for operational procurement of inertia in the NEM, including different procurement models, technical and policy design challenges, and the costs and timing of implementation.

47 The Commission considers there are broadly two operational procurement models (although there could be others):

- a standalone inertia spot market – this model would operate similarly to FCAS markets, with price-quantity bids submitted for each 5-minute dispatch interval.
- reforming existing 1-second Frequency Control Ancillary Services (FCAS) markets to include inertia valuation — this model would integrate inertia directly into the existing ancillary service framework, potentially reducing implementation costs while recognising the distinct characteristics of grid-forming inverters.

48 Both models aim to dynamically co-optimise inertia alongside other system services while leveraging the existing long-term procurement framework.

49 The estimated annual benefits of procuring additional inertia range from modest to significant, depending on implementation costs and uncertainties in supply and demand.

50 Implementation costs are a key consideration, with HoustonKemp independently estimating the net present value of establishing a standalone spot market at $20 million to $50 million over ten years. These costs include setup expenses for AEMO, market participants, and necessary upgrades to market systems. However, additional costs could arise from technical and operational challenges, such as improving real-time inertia monitoring or adapting AEMO's dispatch engine to manage complex optimisation requirements. AEMO has not yet considered these costs in full and we are working with AEMO to get their thoughts on these costs.

51 The Commission highlights several technical and policy challenges that require further investigation. These include

- understanding the locational versus global nature of inertia requirements,

- integrating grid-forming inverters, and
- addressing operational challenges related to the long lead times of some synchronous units.

52 Market design decisions, such as bid structures, cost allocation mechanisms, and compliance arrangements, will influence the efficiency of operational procurement and the net benefits to consumers. Ensuring compatibility between operational and long-term procurement frameworks is another critical design consideration, particularly in managing interactions between AEMO's contract enablement process and operational markets.

53 Timing and staging are important considerations for implementation. The Commission notes that many benefits from operational procurement are projected to materialise in later years, when uncertainties around synchronous condenser deployment and grid-forming inverter uptake are expected to decline.

54 A staged implementation approach could help manage regulatory change, allowing additional inertia to be procured through contracts initially before transitioning to a more complex operational procurement model. This phased approach mirrors the evolution of FCAS markets in the NEM, providing time for stakeholders to adapt while refining technical and policy frameworks.

55 Stakeholder feedback is crucial to refining these implementation considerations. The Commission seeks input on the costs and benefits of different procurement models, the feasibility of technical solutions, and the balance between regulatory certainty and future flexibility.

Submissions are due by **Thursday, 5 February 2025** with other engagement opportunities to follow

56 There are multiple options to provide your feedback throughout the rule change process.

57 Written submissions responding to this consultation paper must be lodged with the Commission by **Thursday**, **5 February 2025** via the Commission's website, www.aemc.gov.au.

58 There are other opportunities for you to engage with us, such as one-on-one discussions. See the section of this paper below about "How to make a submission" for further instructions and contact details for the project leader.

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the solution by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and contributes to well-informed, high quality rule changes.

How to make a written submission

Due date: Written submissions responding to this Directions Paper must be lodged with Commission by Thursday 5 Feburary 2025.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the 'lodge a submission' function under the 'Contact Us' tab, and select the project reference code ERC0339.[1]

Tips for making submissions on rule change requests are available on our website.[2]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[3]

For more information, you can contact us

Please contact the project leader with questions or feedback at any stage.

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1 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission

2 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3

3 Further information about publication of submissions and our privacy policy can be found here: https://www.aemc.gov.au/contact-us/lodge-submission

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1.1 We are considering inertia in a broader context of a transitioning system

This directions paper sets out the Commission's current direction for its consideration of how inertia should be most efficiently provided in the NEM. We are considering this rule change within the context of the significant shift that is currently occurring in the NEM. The shift from a fossil fuel based, synchronous, power system to a renewables-dominated power system introduces new economic and technical challenges to ensuring secure and reliable operation at all times. The main reasons for this are:

- more active and diverse participants
- greater dependence on, and vulnerability to, weather
- the emergence of new technologies.

The ongoing evolution to a net zero energy system, and the emergence of new technologies, will necessitate an even greater focus on new security challenges, while also providing new opportunities to address these.

Relevant to this rule change is that as the energy transition progresses and the power system decarbonises, the historical sources of inertia are expected to retire at an increasing rate, leading to declining inertia provided by synchronous generation. The system's inertia needs are likely to evolve in the future, as are the technologies capable of providing it. The near-term decline in inertia and longer-term technology evolution give rise to questions about how to most efficiently meet the system's inertia needs. There are also interactions between any 'inertia' service and other system services required in the system, as well as how these are provided.

It is in this context that we are considering this rule change. We recognise that we are still building the knowledge and operational experience to understand the best methods to manage security in the longer-term. Our proposed directions set out in this paper are focused on what we think the most effective and efficient way to consider how we procure and value inertia given today's knowledge. As we build our system and the system continues to evolve, further changes to market design will likely be justified. We set out our views on how this may occur and our considerations on this throughout this paper.

1.2 The AEC has proposed an inertia spot market to provide a secure and efficient level of inertia

The AEC submitted a rule change request to the AEMC in December 2021, identifying a need to reconsider the existing inertia framework in the context of declining system inertia and the need to support the rapid energy transition and associated system needs. The AEC's rule change request can be found on the AEMC's project webpage: "Efficient provision of inertia".

In the rule change request, the AEC:

- **Proposes** an ancillary service spot market for inertia as a solution to address the problems identified in its rule change request and best meet the NEO. The AEC's proposed inertia spot market is envisioned as a real-time procurement mechanism that would support the secure operation of the power system by valuing and securing inertia in operational timeframes.

- **Suggests** that the key benefits of this solution would include providing a price signal and forecasting certainty to promote efficient investments in inertia sources and allowing inertia to be co-optimised with other NEM spot markets to reduce total dispatch costs, which would benefit consumers.
- **Recognises** that in considering this rule change request, further work is needed to understand the technical requirements of the system for inertia and the best approach to manage inertia in the future.

On 2 March 2023, the Commission published a consultation paper in response to the AEC rule change request. The consultation paper outlined the key challenges of managing inertia within the framework that existed at the time and which has subsequently been modified by the *Improving security frameworks for the energy transition Rule 2024 No.9 (ISF Rule)* . The consultation paper sought stakeholder feedback on the AEC's proposed spot market model and alternative approaches, aiming to explore options that ensure a secure and economically efficient NEM.

Following the March 2023 consultation paper, the Commission decided to prioritise finalising the ISF rule change to first streamline the inertia procurement framework in the planning timeframe. The final determination for the ISF Rule noted that the Commission would consider operational procurement of inertia through the Efficient provision of inertia rule change.

Therefore, this Directions Paper progresses the Commission's consideration of the efficient provision and valuation of inertia, focused on the operational timeframe given the context set out above.

1.3 The Commission is considering operational procurement options for inertia in this rule change

We focus in this paper on the operational procurement of inertia in the NEM, while recognising that of course there is a link between operational outcomes and the investment timeframe.

Operational procurement options are mechanisms that allow inertia to be procured in 'real time' (every 5 minutes) alongside the energy and frequency markets. Examples include an inertia spot market or reform of the existing frequency markets to allow the procurement of inertia to meet RoCoF needs — see chapter 8.

We recently progressed improvements to the long-term procurement arrangements for inertia through the ISF Rule. This approach allowed the AEMC to progress the simpler long-term procurement opportunities under the ISF first. We considered that was the most effective and efficient way to address the immediate and medium-term transitional issues in relation to inertia.

The ISF reforms did not and do not preclude the Commission's consideration of the options discussed in this paper. While the tools provided by that Rule change are focused on addressing the immediate and medium-term transitional issues, to meet the challenges of operating a transitioning system right now, we are still building the knowledge and operational experience to understand the best methods to manage security in the longer-term. As we build this knowledge and the system continues to evolve, further changes to market design may be justified.

The Commission still considers that the ultimate goal — if both technically feasible and economically justifiable — remains the independent procurement and valuing of security services. We recognise that this could provide investment and scarcity signals for participants to deliver these services at least cost to consumers.

1.4 This paper focuses on assessing the economic case for operational procurement, rather than detailed technical considerations

This Directions Paper invites stakeholder feedback on the Commission's economic assessment of introducing operational procurement of inertia in the NEM. This will inform the Commission's consideration of the AEC's rule change request.

In preparing this Directions Paper, the Commission has focused on evaluating the economic case for operational procurement of inertia. This analysis provides a high-level understanding of whether the benefits of a real-time procurement mechanism could justify its further detailed exploration.

To fully evaluate whether operational procurement of inertia should be introduced into the NEM, both economic and technical analyses are required.

AEMO is continuing to advance the work on better understanding the needs of a transitioning power system. It has undertaken valuable preliminary work that informs the current discussion. For instance, recent studies, such as the Vysus Group analysis and collaborative work with TasNetworks, offer insights into the evolving role of inertia in the NEM and potential operational needs. Further, AEMO has developed resources such as the Voluntary Specification for Grid-Forming Inverters and plans to design trials and conduct targeted stability studies in FY 2025, which are expected to contribute to the technical foundation for future considerations.

However, more work is still required to assess the technical feasibility of operational procurement of inertia in a definitive, conclusive manner. Key areas for further exploration include the locational versus global nature of inertia requirements, the technical integration and coordination of grid-forming inverters, and the practical challenges associated with dynamically co-optimising inertia alongside other system services. This includes assessing any limitations or mitigations that may be necessary for the market design and implementation.

To some extent, the work required would also depend on the preferred procurement design for inertia. AEMO has not included such work in its current technical priorities. We recognise that this body of work would require significant time and resources from AEMO and the significant program of technical priorities that it is currently progressing. The Commission considered engaging our own independent technical advice but decided not to as it would be difficult to conduct thorough, robust technical analysis without drawing on AEMO resources and expert knowledge as the system operator.

Recognising that more detailed technical work is needed, but is not yet possible at this time, the Commission has adopted a pragmatic approach for this Directions Paper, relying on simplifying assumptions to assess the economic case under an illustrative scenario. These assumptions include treating inertia requirements as global rather than locational, assuming an ideal integration of grid-forming technologies, and postponing consideration of certain implementation challenges to first focus on economic benefits. The findings from this assessment, along with stakeholder feedback, will help determine whether further investigation into the technical feasibility and implementation of operational procurement is warranted as part of the next stage of the project.

1.5 We are seeking your feedback on our economic assessment methodology, the findings, and the implications for operational procurement approaches

The Commission engaged Houston Kemp to provide economic advice and analysis to explore the economic case for the different options for operational procurement of inertia. This analysis examines both minimum levels of inertia to ensure security (‘minimum inertia requirement’, or ‘minimum inertia demand’) and additional levels of inertia above the minimum (‘additional inertia demand’). It recognises a range of potential system planning and investment scenarios within the NEM’s evolving power system.

The primary goal of this analysis was to assess whether inertia possesses the necessary economic characteristics to justify operational procurement of inertia, and if so, assess whether the expected benefits from operational procurement are substantial enough to support further exploration of detailed technical and implementation considerations.

The Commission’s key findings from this economic assessment are outlined in this Directions Paper for stakeholders’ consideration and feedback.

This consultation process is a crucial step in ensuring that any forward direction takes into account stakeholders’ perspectives and enables the identification of a solution that best contributes to the NEO.

Ultimately, this Directions Paper establishes a foundation for the Commission’s continued consideration of the best approach to address inertia requirements in the NEM. The insights gathered from stakeholders will be instrumental in shaping the Commission’s next steps on this rule change.

1.6 Submissions are due 5 February 2025

We are seeking feedback on the findings outlined in this Directions Paper.

Due date: written submissions to this Directions Paper must be lodged with the Commission by 5 pm, 5 February 2025.

How to make a submission: Go to the Commission’s website, www.aemc.gov.au, find the ‘lodge a submission’ function under the ‘Contact Us’ tab, and select the project reference code ERC0339.

Tips for making submissions on rule change requests are available on our website.

2 The Commission is responding to stakeholder feedback on the consultation paper

2.1 The Commission's consultation paper outlined the problem definition and possible solutions

The Commission's consultation paper[4] identified the challenge of maintaining power system security as the NEM transitions away from conventional synchronous generators, which inherently provide inertia.

The paper summarised the key challenges identified in the AEC's rule change that it sought a solution to. These included declining system inertia and associated risks to the power system, potential efficiency benefits of procuring inertia in real-time and the need to provide clear investment signals to meet long-term inertia needs.

To address these challenges, the consultation paper outlined a range of options across the potential spectrum of options for procurement and valuation (see section 1.3), including:

1. Inertia spot market: One option is a separate, spot market for inertia, allowing for real-time procurement of inertia. This market-based approach would enable the dynamic valuation and acquisition of inertia, co-optimising it with energy and other system services to respond to changing system needs in real-time.
2. RoCoF control service: Under this option, similar to the WEM, a RoCoF control service could focus directly on managing the rate of change of frequency in the NEM. This could potentially enable greater participation from inverter-based resources while directly addressing system stability requirements without relying solely on inertia.
3. Long-term procurement: This option proposed a planning timeframe framework where TNSP would be responsible for procuring inertia through structured, contract-based arrangements.

These represent just three possible options for how operational procurement and valuation could be undertaken. We are aware that this is not an exhaustive list of options, but consider these provide a useful spectrum to frame the discussion.

2.2 Stakeholder submissions broadly agreed with a need for an efficient and effective framework for inertia, but views varied on a preferred solution

Stakeholder submissions to the consultation paper broadly agreed on the need for an enduring framework to support the efficient provision of inertia. However, stakeholders expressed diverse views on the optimal framework:

- The AEC, its members and other industry stakeholders[5] expressed their preference for an inertia spot market, highlighting its potential for market efficiency and alignment with existing dispatch processes.
- Some stakeholders[6] supported the exploration of a RoCoF control service as an alternative market arrangement, noting it could be an effective, emissions-conscious solution aligned with evolving system needs.

4 AEMC, Efficient provision of inertia, Consultation paper, 2 March 2023.

5 Submissions to the consultation paper: AEC, AGL, Alinta Energy, CS Energy, Delta Electricity, Energy Australia, Origin, Shell Energy, Stanwell, Snowy Hydro and ZigerEnergy.

6 Submissions from Clean Energy Council (CEC), CS Energy, Iberdrola, Justice and Equity Centre (JEC, formerly PIAC) and Shell Energy

- On the other hand, AEMO, TNSPs and some other stakeholders[7] expressed a preference for enhancements to the structured procurement framework, citing stability and cost predictability as priorities.

2.3 Stakeholders agreed further work is needed to inform the enduring inertia framework

In their submissions, stakeholders broadly agreed that further work is required to decide on the most effective and enduring framework for managing inertia.

Several submissions[8] highlighted the need for more detailed technical understanding to accurately define inertia requirements. Stakeholders pointed to gaps in knowledge regarding the specific levels and characteristics of inertia necessary for system security, noting that further technical work would help refine the framework's design and implementation considerations. Some stakeholders suggested that further technical work should also consider the opportunities for the greater use of synthetic inertia.[9]

Stakeholders also called for further assessment of the interactions between inertia and other system services, such as system strength. They argued that aligning the framework for inertia with broader system security services would improve efficiency and ensure a cohesive approach to managing stability as the NEM transitions.[10]

2.4 The Commission is responding to stakeholder feedback by further considering the economic case for the operational procurement of inertia

Since the publication of the consultation paper, the Commission has enhanced the long-term procurement framework for inertia through the ISF Rule.

In relation to this rule change, the Commission has also made progress on its work on evaluating the economic case for operational procurement of inertia. As outlined in Section 1.3, this Directions Paper focuses on the economic assessment, which is intended to inform whether there is an economic case for further considering operational procurement in more detail.

However, the Commission also recognises the need for technical advice to inform our considerations of the operational timeframe procurement and valuation of inertia. The findings of this economic assessment and stakeholder feedback will help the Commission determine the nature and scope of further assessment required as part of the next stage of the project, the draft determination.

Based on stakeholder feedback on the Consultation Paper, the Commission has formed and sought input for this project from a Technical Working Group (TWG) in progressing the economic assessment as part of the Directions Paper.[11] This group consists of experts from various parts of the energy sector, including generators, TNSPs, consumer groups and market bodies.

7 Submissions from AEMO, AER, Energy Network Association (ENA), TransGrid, TasNetworks, NEOEN, Tilt Renewables and Energy Users Association of Australia (EUAA)

8 Submissions from AEC, AEMO, AGL CEC, Alinta Energy, CS Energy, Delta Eletricity, ENA, EnergyAustralia, EUAA, Goldwind Australia, Iberdrola, NEOEN, Origin, JEC, Shell Energy, Snowy Hydro, Stanwell, TasNetworks, Tesla, Tilt Renewables and Transgrid.

9 Submissions from AEMO, CEC, ENA, Goldwind Australia, Origin and JEC (former PIAC).

10 Submissions from AEMO, AER, ENA, Iberbrola, TasNeworks, Tilt Renewables and TransGrid

11 Several submissions recommended that the Commission establish a technical working group or engage independent economic and technical advisors to progress further analysis. These stakeholders considered that this would ensure that any framework ultimately adopted is based on a robust, transparent understanding of the technical, economic, and operational implications of inertia management.

This Directions Paper seeks feedback from stakeholders on the economic assessment framework and approach in response to what is set out in this paper.

3 Making our decision

3.1 Decision-making on this rule change will consider the National Electricity Objective

The Commission will make a decision in line with the NEO under the National Electricity Law (NEL). The Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO. This is the decision-making framework that the Commission must apply.

Since commencing the inertia rule change in March 2023, Energy Ministers approved amendments to the national energy laws to incorporate an emissions reduction objective into the NEO, National Energy Retail Objective, and National Gas Objective. These amendments commenced on 21 September 2023.

The NEO is:[12]

> 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, at minimum, in regard to the NEO.

When considering whether the final rule will or is likely to contribute to the achievement of the NEO, the Commission will consider the assessment principles outlined in section 3.2, as well as any other relevant factors.

3.2 The Commission is considering the case for operational procurement of inertia against the assessment criteria

The Commission has 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:

- **Safety, security, and reliability**: Inertia is crucial for system security, helping to maintain stable voltage and frequency. Although consumers don't demand inertia directly, they expect secure and reliable electricity. The assessment considers potential security improvements from the proposed rule change and their costs, noting that future technology advancements could enable consumers to provide inertia.
- **Emissions reduction**: System security measures should support Australia's emissions reduction targets. This criterion assesses whether market and regulatory arrangements contribute to reducing greenhouse gas emissions, aligning with governmental objectives.

12 Section 7 of the NEL.

- **Principles of market efficiency**: This criterion evaluates whether the proposed framework promotes efficiency across different timeframes. Considerations include efficient operation and allocation, short and long-term incentives, transparency and competition.
- **Implementation considerations**: In assessing this rule change, the Commission will consider the implementation costs relative to their benefits
- **Innovation and Flexibility**: Regulatory arrangements should be adaptable to changing market conditions and facilitate long-term security. Solutions should accommodate diverse jurisdictions, minimise compliance costs, and promote technological innovation by providing incentives for new technologies.

4 Inertia is a fundamental system need

Box 1: Key points in this chapter

- Inertia is a fundamental characteristic of the power system that is vital for system stability through:
  - instantaneously and inherently responding to frequency disturbances, both during normal system conditions and following contingency events
  - limiting the rate of change of frequency following large disturbances
  - damping oscillations between plant that may otherwise be unstable.
- Inertial responses can be provided by:
  - synchronous generators and load, such as coal, gas and hydro plant
  - synchronous condensers (with or without flywheels)
  - grid-forming inverter-based plant that are able to maintain a local stable voltage waveform.
- A minimum level of inertia is always needed for secure operation to ensure that system frequency and voltages stay within acceptable limits. This minimum inertia requirement must also be appropriately distributed throughout the NEM for secure operation.
  - **Minimum inertia** demand varies in real-time dispatch. This is because dispatch outcomes and system conditions change the set and nature of the contingency events that may result in the largest frequency disturbances - varying the real-time inertia needs.
- **Additional inertia** is any inertia above the minimum level that may reduce energy or FCAS dispatch costs. It may reduce costs by reducing FCAS requirements or relieving binding constraints with inertia terms.
  - The demand for additional inertia may sometimes be zero, and depends upon market participant bids and dispatch outcomes.
  - Currently, there is no mechanism by which additional inertia demand is explicitly calculated or met. Determining the high-level benefits of meeting additional inertia demand is one of the key objectives of this directions paper.
- Under the inertia framework introduced by the ISF Rule, AEMO determines and publishes inertia requirements over a 10-year horizon. These inertia requirements are published annually and include a system-wide inertia level (for interconnected operation), as well as minimum regional requirements (which depend on whether the region is at risk of islanding).
- TNSPs are obliged to make available this amount of inertia available through either network investment or long-term contracts. They may choose to use inertia support activities (such as contracted FFR) to reduce their binding requirements.
- From 2 December 2024, AEMO will be able to enable TNSP contracts to ensure that minimum inertia demand is always met in real-time.

4.1 Inertia is essential to the power system

In the context of an alternating current (AC) electrical power system like the NEM, inertia refers to the capability of the power system to instantaneously resist changes in frequency. Generally, a high-inertia system will experience slower changes in frequency (both during normal system conditions and after large disturbances) compared to a low-inertia system.

Inertia is essential to the power system as it helps maintain system frequency and voltages within secure and safe limits.[13] If the frequency rises or falls beyond acceptable limits due a contingency event, then plant or network equipment may trip. In the worst cases, if sufficiently widespread or large, these trips can cause their own large frequency disturbance, potentially leading to a cascading outage or black system event.

In the NEM, the Frequency Operating Standard (FOS) sets out various frequency bands and requirements.[14] For example, following a credible contingency event, AEMO must ensure that the rate of change of frequency does not exceed 1 Hz/s on the mainland, and 3 Hz/s in Tasmania.[15]

Although inertia is not the only characteristic of a power system that can help maintain system security, it plays a fundamental role by:

- providing an immediate and inherent response to any changes in frequency through active power exchanges that cannot be substituted by any other type of response
- limiting the rate of change of frequency (RoCoF)[16] following a large disturbance, providing enough time for other responses (for example, fast frequency response or emergency frequency control schemes) to act to return the frequency back to 50 Hz — see Figure 4.1
- damping oscillations that may occur between plant and sub-regions of the power system that may otherwise be unstable with less inertia — Figure 4.2.

It is important to note that the characteristics and performance of many connected plant, network equipment and facilities also contribute to frequency stability through their operation, despite not necessarily providing inertial responses. The access standards and system standards, as set out in Schedule 5 of the National Electricity Rules (NER), define stringent requirements for the capability of connected plant, with some access standards requiring plant to directly contribute to frequency stability following a fault and during normal operation.[17]

13 In the NEM, the nominal frequency is 50 Hz.

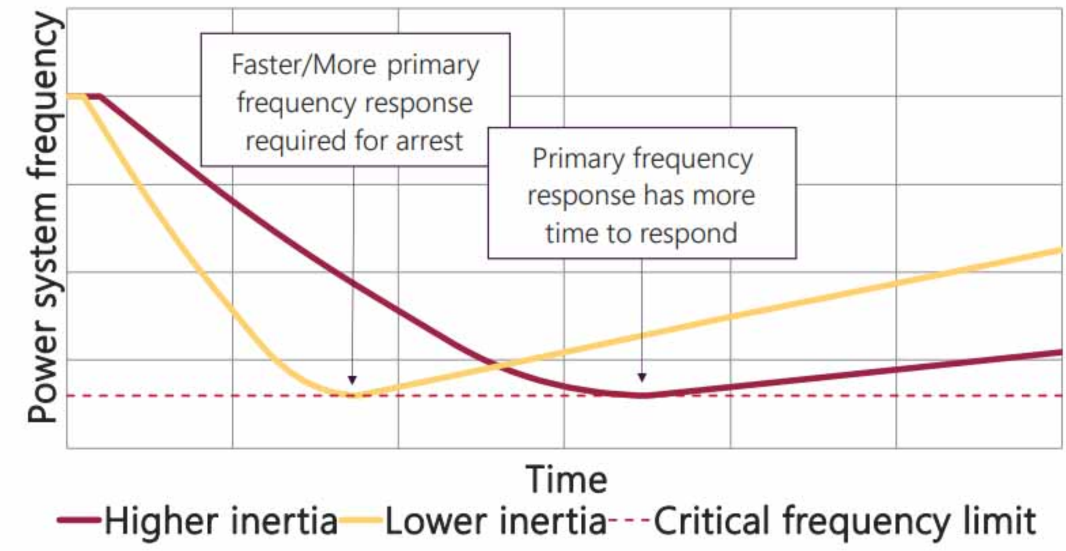
14 AEMC, Frequency Operating Standard (October 2023).

15 AEMC, Frequency Operating Standard, p 4. These requirements are measured over any 500 millisecond period. Rate of change of frequency limits were recently added in by the Reliability Panel's Review of the Frequency Operating Standard 2022.

16 Inertial responses are proportional to the **rate of change** of frequency. This is different to fast frequency response (FFR), where responses are droop-based — that is, proportional to the **change** in frequency from 50 Hz.

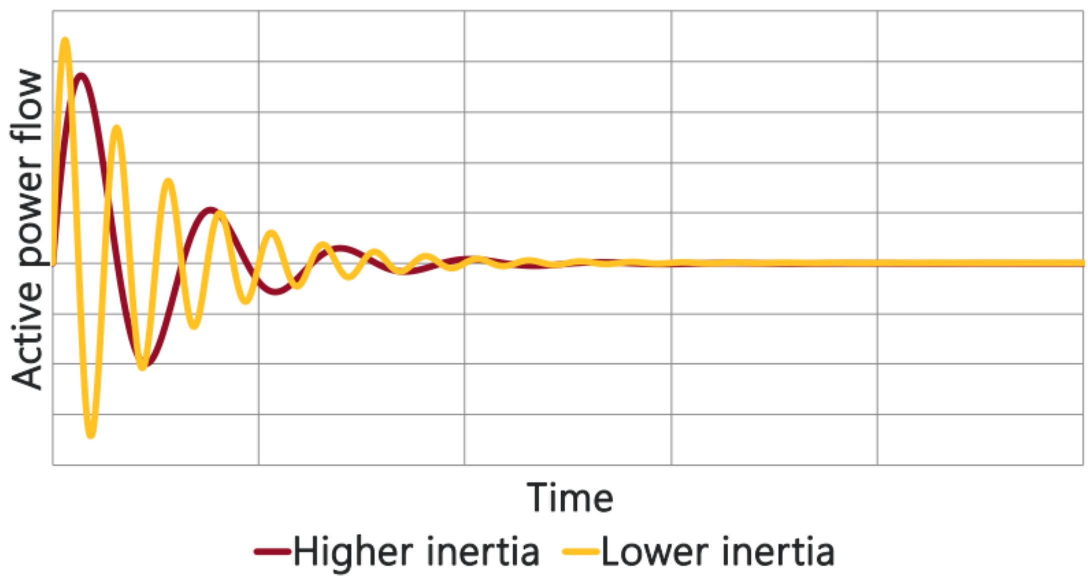
17 For example, NER clause S5.2.5.8 requires that all generating systems over 30 MW and bidirectional units over 5 MW must be capable of reducing their active power rapidly in the event of an over-frequency event, in order to return the system frequency back towards 50 Hz.

Figure 4.1: Inertia provides more time for fast frequency responses to respond



Source: AEMO, Inertia in the NEM explained, p 2.

Figure 4.2: Lower levels of inertia may increase damping requirements for plant and networks to ensure oscillations can be stabilised



Source: AEMO, Inertia in the NEM explained, p 3.

4.2 Inertial responses can be provided by synchronous machines or asynchronous plant

4.2.1 Synchronous inertia is inherently provided by synchronous generators and condensers

In the past, energy production in the NEM was primarily delivered by **synchronous** plant. A synchronous plant generally has a rotating turbine or rotor that, when operating, rotates at the same speed and frequency as the power system. This synchronisation between the plant and the power system gives rise to **synchronous inertia.**

Coal, gas and hydro plants are examples of synchronous plant that provide inertial responses and are called 'synchronous generators' or 'synchronous machines'. Synchronous condensers are a type of plant that does not produce active power, but are synchronously connected to the power system and also provide inertial responses.[18]

Synchronous inertia is the kinetic energy that is associated with the rotating mass of a synchronous plant. When power system frequency declines, the kinetic energy of the rotating mass is transferred to the grid as electrical energy, slowing down the turbine or rotor slightly. Conversely, when power system frequency increases, some electrical energy from the grid is transferred to the plant as kinetic energy, increasing the speed of the turbine or rotor.

This transfer of energy is inherent and instantaneous, as it is a consequence of electromagnetic phenomena and the conservation of energy. Therefore, a synchronous plant delivers the **same amount of inertia whenever it is synchronised to the grid**, which is independent of the plant's operating point or any other external influences.

Inertia is typically measured in megawatt-seconds (MWs), which refers to the amount of energy that can be transferred between the synchronous plant's rotating mass and the power system.[19] The amount of inertia provided by a synchronous plant generally depends upon its rotor's mass and shape.[20]

The inertia of a plant can also be described by an 'inertia constant', typically denoted by H, with a unit of seconds, with the following formula:

$$H\ (s) = \frac{inertia\ (MWs)}{maximum\ power\ rating\ of\ plant\ (MW)}$$

Typical inertia constants for synchronous plant in the NEM are in Table 4.1 below:

Table 4.1: Typical inertia constants for synchronous plant

Plant type	Range of inertia constant (seconds)
Coal	2.5 – 5.5
Gas (both open-cycle and combined-cycle gas turbines)	4.0 – 12.0
Hydro	2.4 – 6.5
Synchronous condenser[1] (without flywheel)	1.0 – 3.6 [2]

Source: AEMC, using AEMO MMS data.
Note: [1] For a synchronous condenser, the constant is calculated with reference to the condenser's apparent power rating in MVA.
[2] Based on Andritz, Synchronous Condensers - The Smart Solution for Modern Grids, *p 8.*

18 Some synchronous generators can undergo conversion to become synchronous condensers. For example, see DigSILENT's report on Repurposing existing generators as synchronous condensers (June 2023).

19 For example, a plant with 100 MWs of inertia can deliver energy at a rate of 50 MW for 2 seconds, or at a rate of 100 MW for 1 second.

20 Specifically, it depends upon a rotor's *moment of inertia*, calculated as $\int r^2\,dm$, where r is the distance of a small mass dm from the axis of rotation.

A flywheel can also be installed onto a synchronous condenser which provides it with more mass, and therefore more inertia. For example, ElectraNet has commissioned four synchronous condensers with flywheels, each providing about 1100 MWs of inertia[21] (with each unit having an approximate inertia constant of 8.8 seconds[22]).

4.2.2 Synthetic inertia can be provided by grid-forming inverters that emulate the inertial response of a synchronous plant

Inverter-based plant is connected to the power system through an inverter, which converts the direct current (DC) power generation from solar modules, wind turbines or batteries, to AC waveforms that can be safely transmitted through the network. Therefore, these inverters are not electromagnetically synchronised in the same way as synchronous plant and do not provide synchronous inertia.

However, some types of inverters are able to provide responses to frequency disturbances that are very similar to a synchronous plant. These **grid-forming inverters** are able to maintain a stable voltage waveform, with its magnitude and frequency set locally by the inverter (that is, it does not depend on any external frequency or voltage measurement).[23] After a frequency disturbance, a grid-forming inverter is able to instantaneously inject or absorb current (and consequently, active power) in a similar manner to a synchronous plant. This is known as **synthetic inertia.**

The amount of synthetic inertia that is provided by a grid-forming battery depends on various factors, unlike synchronous plant where inertia only depends on the plant's rotating mass and its shape. For example, the amount of synthetic inertia depends on the inverter's operating point[24] at the time of the frequency event (see Figure 4.3), and the contingency size that led to that frequency disturbance (see Figure 4.4).

This means that operators of grid-forming inverter-based plant may need to reserve headroom or footroom (that is, operate the plant below its maximum charge or discharge rate) in order to provide a significant amount of synthetic inertia.

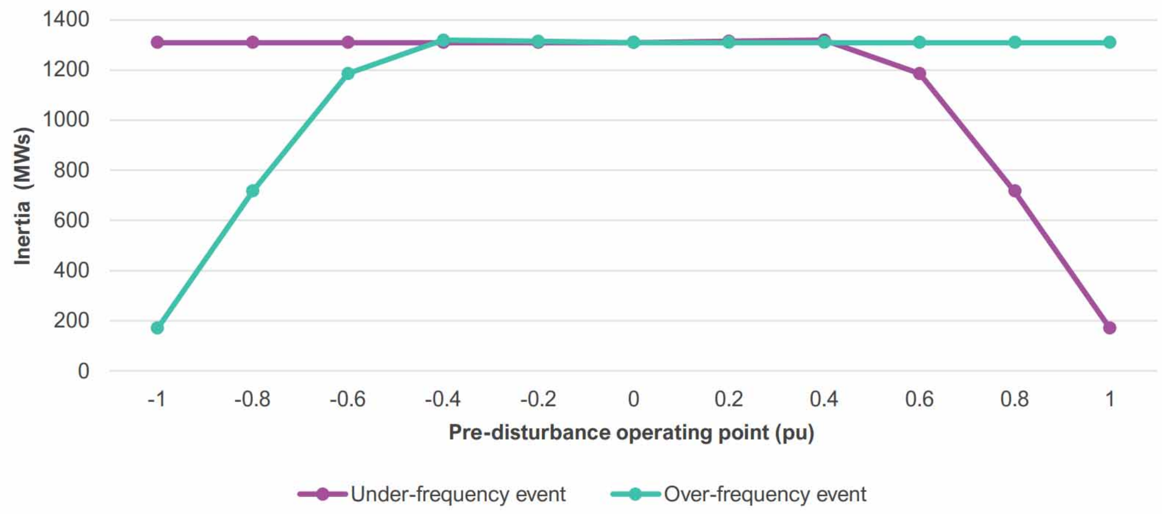
21 AER, Final Decision for ElectraNet Contingent Project Application (August 2019), p 7.

22 Assuming each installed synchronous condenser is rated at 125 MVA — see ElectraNet's System Strength PSCR (November 2023), p 4.

23 AEMO, Voluntary Specification for Grid-forming Inverters (May 2023), p 7.

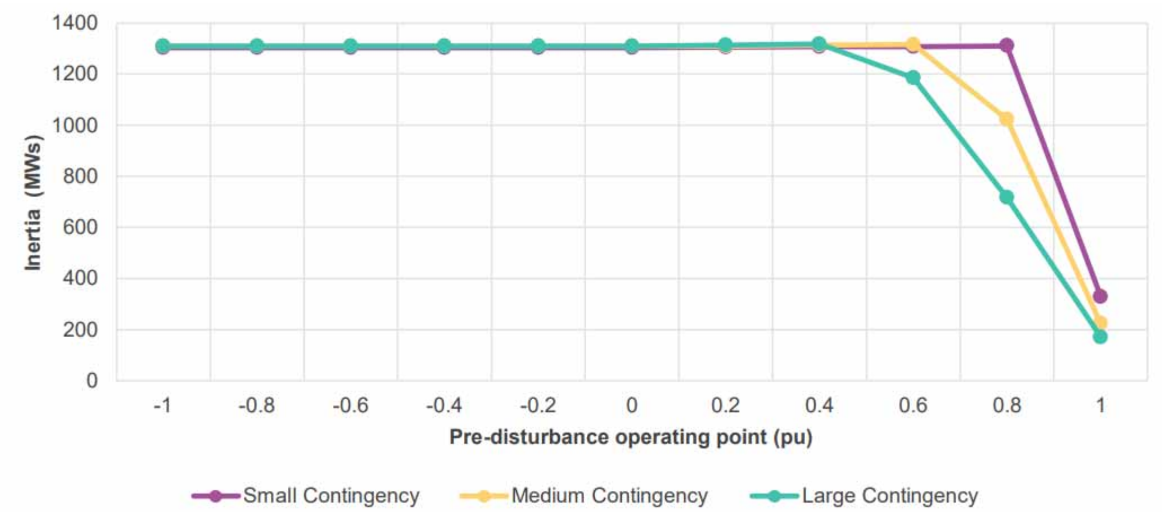
24 An inverter's operating point is its power when delivering or absorbing energy from the grid. For example, if an inverter's operating point is 100 MW, it is delivering 100 megajoules of electrical energy per second to the grid. If its operating point is 0 MW, it is neither charging nor discharging any electrical energy.

Figure 4.3: Synthetic inertia of a grid-forming inverter at different operating points for a fixed contingency size



Source: AEMO, Quantifying Synthetic Inertia from GFM BESS, p 14.

Figure 4.4: Impact of contingency size on synthetic inertia from a grid-forming inverter



Source: AEMO, Quantifying Synthetic Inertia from GFM BESS, p 15.

Because the voltage waveform (or phasor) is able to be set locally by the inverter, the inverter's settings can be tuned or adjusted to modify its response characteristics in any desired fashion. For example, the Hornsdale Power Reserve can provide about 2,070 MWs of inertia (an equivalent H constant of 11.02 s) but could vary its inverter response characteristics so that it can provide up to 3,000 MWs of inertia.[25]

However, due to current regulatory requirements, grid-forming inverters are not able to vary their inertia responses operationally.[26] If the operator of a grid-forming plant wishes to change their inverter's response characteristics, they must currently undergo a clause 5.3.9 process to alter the

25 Neoen, Hornsdale Power Reserve Expansion Final Report (August 2024), pp 10, 18.
26 Ibid., p 18.

relevant performance standards in their connection agreement, in accordance with the requirements of the NER.

Grid-forming inertial responses from inverters is an active area of electrical engineering research to better understand their interactions, especially in inverter-based resource dominated systems. AEMO has developed its inertia network services specification that sets out the technical requirements that synchronous and asynchronous plant must meet in order to provide inertia in a stable and safe manner.[27] Through its Engineering Framework, AEMO has also published other specifications and reports into how it expects synthetic inertia can substitute and complement synchronous inertia to meet power system needs.[28]

4.3 We consider that inertia demand can be separated into ‘minimum inertia demand’ and ‘additional inertia demand’

This section discusses how we conceptualise the system need for inertia — or inertia ‘demand’ — in operational timeframes.

4.3.1 Minimum inertia demand is inertia that is required for the secure operation of the power system

As described in section 4.1, inertia is essential for the stable and secure operation of the power system. It ensures that the power system:

- can withstand rapid and large changes to system frequency, caused by a contingency event or similar large disturbances.
- is not prone to instability through inadequate damping, which could otherwise lead to unstable frequency or voltage oscillations.

The largest frequency disturbances are generally caused by large contingency events, such as:

- the loss of a large generating unit
- the loss of a large load (such as an industrial load)
- separation events, where the loss of a transmission element results in a region or sub-region of the NEM being islanded.[29]

In real-time, changes in dispatch outcomes, network constraints, interconnector flows and other system conditions may also change the set of contingency events that can cause the largest frequency disturbances. To ensure that the system can remain in a secure operating state, there must be sufficient inertia across the NEM distributed in such a way that the system can be in a satisfactory operating state after experiencing any credible contingency event.[30] This inertia comes from all synchronous plant that are operating and synchronised to the power system, as well as any grid-forming inverters that are online and able to deliver synthetic inertia (that is, operating with sufficient headroom/footroom and enabled to deliver an inertial response).

Therefore, there is a **minimum level of inertia**[31] that is required for the secure operation of the power system at any point in time, which must also be **appropriately distributed** across the NEM. This inertia can be thought of as the **minimum inertia demand,** or **minimum inertia requirement,** of the power system. If the power system does not meet this minimum inertia demand (while

27 AEMO, Inertia Requirements Methodology, Appendix A.

28 AEMO: Quantifying Synthetic Inertia of a Grid-forming Battery Energy Storage System - Technical Note (September 2024), Voluntary Specification for Grid-forming Inverters: Core Requirements Test Framework (January 2024), Voluntary Specification for Grid-forming Inverters (May 2023).

29 AEMO, Draft Inertia Requirements Methodology, pp 17-18.

30 The power system is in a secure operating state if, after experiencing a credible contingency event or protected event, it would be in a satisfactory operating state (that is, a secure operating state is akin to operating at an ‘n-1’ contingency level). See NER clauses 4.2.2 and 4.2.4.

31 This is not to be confused with the *minimum threshold level of inertia*, as was defined in the NER at clause 5.20B.2 prior to 1 December 2024.

considering the distribution of inertia), then the system would be considered to be operating in an insecure state.[32]

If inertia is too concentrated in a particular region of the NEM, and a contingency event occurs in an electrically distant region, then the network may not be able to transfer the large amounts of energy required to limit the rate of change of frequency, or to prevent regions from islanding.[33] The distribution of inertia is likely to become increasingly important for the secure operation of the NEM as the aggregate level of inertia in the power system decreases in the near-term.[34]

Additionally, at low aggregate levels of synchronous inertia, the overall stability of the power system becomes more dependent upon the combined synthetic inertia responses from inverter-based plant. This may increase the likelihood of unintended and unstable interactions if stability phenomena at high levels of IBR-penetration are not completely understood.

4.3.2 Additional inertia demand is any inertia that could reduce energy or FCAS dispatch costs

If minimum inertia demand is exceeded at any point in time, there are generally no adverse effects on the power system. Instead, this excess inertia may sometimes help reduce other system requirements, such as the amount of primary frequency response needed in the system for secure operation. It can also allow for more low-cost generation to be dispatched if constraints with inertia terms would otherwise bind. In this directions paper, we have referred to this amount of inertia above the minimum level required for secure operation as '**additional inertia'.**

Currently, there is no mechanism by which additional inertia demand is explicitly calculated or met. **Investigating the potential benefits of meeting additional inertia demand is one of the key objectives of this directions paper.**

There are two primary ways that additional inertia may reduce dispatch costs:

- by reducing 1-second FCAS requirements, which is currently dependent upon the amount of synchronous inertia in the system (that is, if more inertia is present in the power system, then 1-second FCAS requirements are reduced, and vice-versa — see Figure 4.5 for the current relationship between inertia and 1-second FCAS requirements)[35]
- by relieving any binding constraints with inertia terms, which may allow for cheaper dispatch costs depending on constraint formulation and market bids.[36]

32 Conversely, if minimum inertia demand is met or exceeded (even by a large margin), the system is operating securely (assuming all other power system requirements are met).

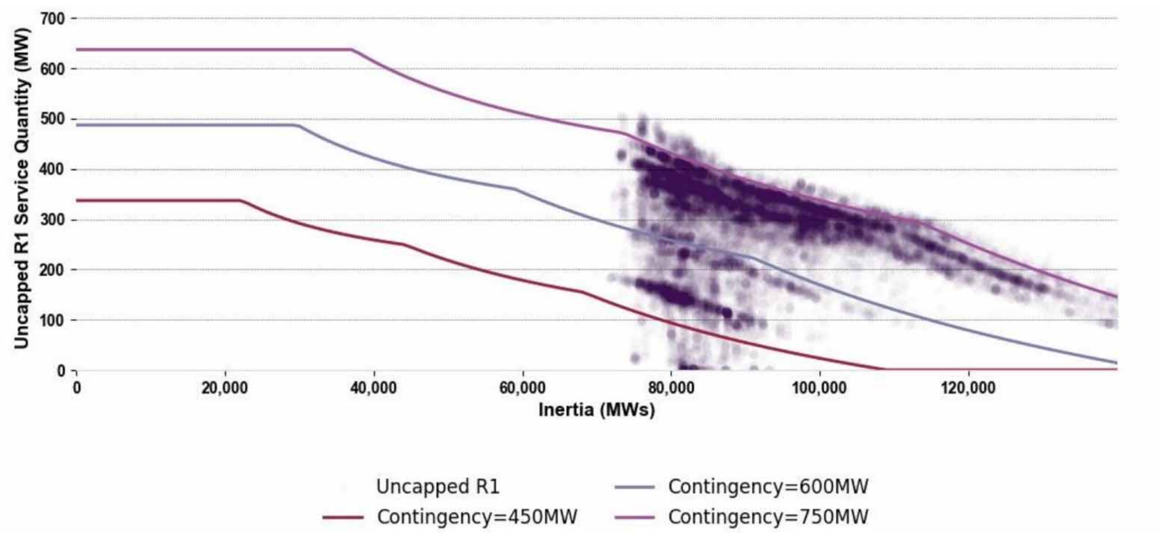
33 AEMO, Inertia in the NEM explained, p 3.

34 See Vysus Groups' report for AEMO, The Role and Need For Inertia in a NEM-like System, which simulated a low-inertia NEM-like system using PSS/E software with different distributions of inertia.

35 AEMO, Frequency Monitoring Q4 2023, pp 12-13; Constraint Implementation Guidelines, p 28, 32. By reducing 1-second FCAS requirements, additional inertia may also result in preventing NEMDE from constraining down generators to reduce FCAS costs, allowing cheaper generation to be dispatched instead. **NB:** NEMDE does not currently constrain down generators to reduce dispatch costs on a regular basis — it only does constrains down generators when there is a scarcity of FCAS. See AEMO, Constraint Formulation Guidelines, pp 20-21.

36 For example, the T_ROCOF_3 constraint limits the sum of Tasmanian wind dispatch and Basslink import flows depending on how much synchronous inertia is present in Tasmania:
$Tas\_Wind_{MW} + Basslink\_Import_{MW} \leq 0.17 \times Tas\_Inertia_{MWs}$
Additional inertia may allow more Tasmanian wind or Victorian generation to be dispatched.

Figure 4.5: Relationship of uncapped 1-second FCAS raise to inertia in Q3 2024

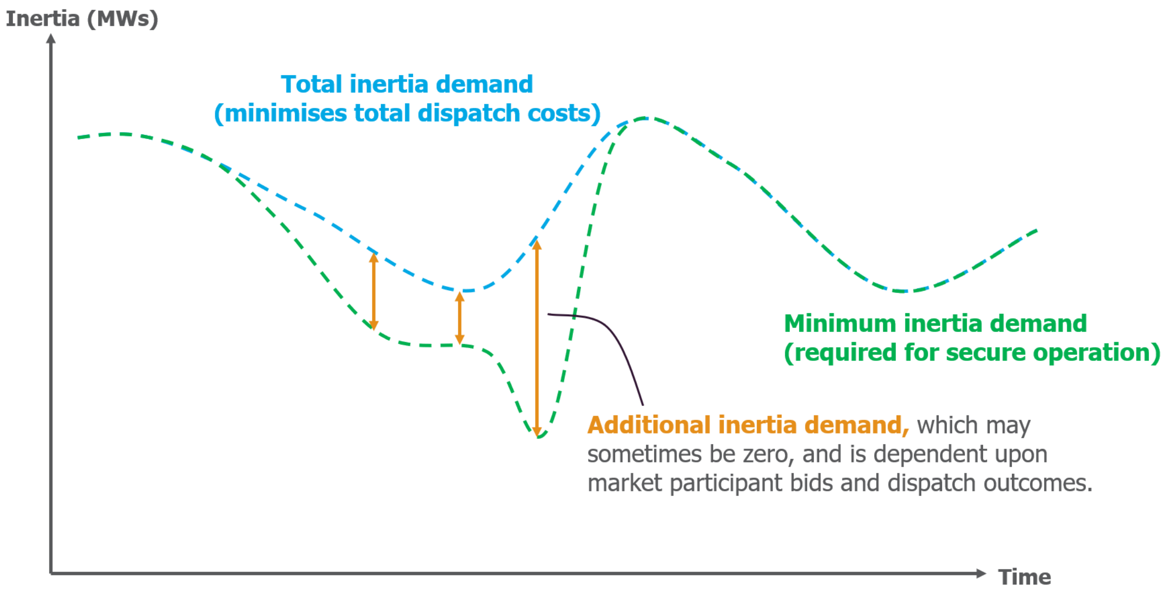


Source: AEMO, Frequency Monitoring Q3 2024, p 13.

Note that the ways in which additional inertia may reduce dispatch costs are dependent upon market participant bids in the energy or FCAS markets. Therefore, at a particular point in time, the amount of **additional inertia demand** may be zero. When additional inertia demand is zero, any excess inertia above the minimum level of inertia that is present in the power system does not affect the clearing prices of the FCAS or energy markets.

The **total inertia demand** during any dispatch interval can be thought of as the sum of the minimum inertia demand and additional inertia demand. See Figure 4.6 for a visual representation of minimum, additional and total inertia demand.

Figure 4.6: Relationship between minimum and additional inertia demand



Source: AEMC

Note: This diagram is for illustrative purposes only and does not represent any intra-day inertia demand projections or forecasts.

4.4 The current inertia framework uses long-term procurement to meet minimum inertia requirements

4.4.1 AEMO forecasts minimum inertia requirements over a 10-year horizon

As a consequence of the Commission's ISF Rule, there have been some recent changes to the inertia procurement framework.[37] Most of these changes commenced on 1 December 2024, and remaining aspects of the new framework commence on 2 December 2025. This section 4.4.1 describes the parts of the inertia framework that commenced on 1 December 2024.

Each year, on 1 December, AEMO must determine and publish the inertia requirements for the next ten years.[38] The inertia requirements are:[39]

- the system-wide inertia level — the minimum amount of inertia required to securely operate the power system when it is interconnected (that is, no mainland region is islanded)
- the inertia sub-network allocations for each region — the proportion of the system-wide level that each region requires for secure operation when interconnected
- the satisfactory inertia levels — the minimum amount of inertia required for each region to be in a satisfactory operating state if it is islanded
- the secure inertia levels — the minimum amount of inertia required for each region to be in a secure operating state if it is islanded
- whether each region is at a credible risk of islanding.

AEMO determines these levels using power system simulation studies, based on the set of all credible contingency events that are expected to occur in the power system over the following ten years.[40] It also models the response from distributed photovoltaic (DPV) systems and load, as well as IBR fault ride-through responses, that may affect the amount of inertia that is required for secure operation.[41]

In addition, AEMO determines inertia requirements as a function of fast frequency response (FFR). This is because contracted FFR and 1-second FCAS can be **inertia support activities,** in recognition of the fact that FFR and 1-second FCAS can help reduce inertia requirements (and vice-versa) (see section 4.3.2).[42]

TNSPs are obliged to make available, for each year, either:[43]

- the inertia sub-network allocation for their region, if AEMO determines that the region does not have a credible risk of islanding
- the secure inertia level for their region, if AEMO determines that the region has a credible risk of islanding.

TNSPs must make these levels available, at least cost, by:[44]

- contracting with generators or integrated resource providers to provide synchronous inertia (or synthetic inertia, subject to AEMO's approval)
- installing, commissioning and operating synchronous condensers.

37 AEMC, Improving security frameworks for the energy transition.

38 NER, clause 5.20B.2.

39 Ibid.

40 AEMO, Draft Inertia Requirements Methodology, pp 16-17.

41 Ibid., pp 17-20.

42 Ibid., pp 23-26, 36-41.

43 NER, clauses 5.20B.2(g) and 5.20B.4. TNSPs are only required to ensure that they make available the required amount of inertia as determined in the inertia report published three years prior — see clause 5.20B.2(g).

44 NER, clause 5.20B.4.

TNSPs may also choose to use **inertia support activities** to reduce their binding inertia levels. These activities could involve contracting with generators for their FFR, or to reduce their output under certain circumstances.[45]

Through AEMO's determination of these inertia requirements, it aims to ensure that minimum inertia demand, as defined in section 4.3.1, is always able to be met through the enablement of TNSP contracts with generators or integrated resource providers. The system-wide inertia level ensures that there is an adequate distribution of inertia throughout the NEM, while the secure inertia levels for each region at risk of islanding ensure that sufficient inertia is present if an islanding event were to occur.

Therefore, minimum inertia demand, which may vary from dispatch interval to dispatch interval, may sometimes be below the system-wide inertia level or secure operating levels that are determined by AEMO. This is because the most severe credible contingency events will not always be a present risk in all dispatch intervals.

4.4.2 AEMO will enable contracts to meet minimum inertia requirements in operational timeframes

AEMO's annual determination of inertia requirements reflect the amount of inertia that is required to operate the system securely under the largest credible contingencies. However, as noted at the end of section 4.4.1, the largest credible contingencies are not always present in real-time dispatch. Therefore, it is necessary to coordinate TNSP inertia contracts in order to meet real-time minimum inertia demand. The parts of the inertia framework introduced by the ISF Rule that facilitate real-time enablement of inertia contracts commence from 2 December 2025.

In its Security Enablement Procedures that must be published by 31 August 2025, AEMO must outline how it intends to determine minimum inertia requirements in real-time.[46] This includes how it will determine real-time inertia requirements for all regions, including for interconnected and islanded operation.[47] These real-time minimum inertia requirements do not need to be the same as the levels determined by AEMO in its annual inertia report as described in section 4.4.1, because these levels will dynamically vary.[48]

As close as practicable to real-time, but no more than 12 hours in advance, AEMO will enable system security contracts that are held by TNSPs to meet minimum system security requirements at least cost.[49] System security contracts include all inertia, system strength, NSCAS and transitional services contracts that are held by TNSPs (or AEMO, in the case of NSCAS or transitional services) with generators or integrated resource providers.

When enabled to provide inertia, the generator or integrated resource provider must provide inertia in accordance with AEMO's instructions. This may involve synchronous plant synchronising or remaining synchronised with the power system, or inverter-based plant reserving headroom or footroom to provide the required inertia.

In order for AEMO to determine the least cost combination of contracts to enable to meet minimum security requirements, TNSPs must provide AEMO with information about the

45 AEMO, Draft Inertia Requirements Methodology, p 10.

46 AEMO must also outline how it will determine minimum three phase fault levels for system strength, and any NSCAS or transitional service needs — see NER clause 4.4A.3.

47 NER, clause 4.4A.3(b)(1)-(3).

48 NER, clause 4.4A.3(c).

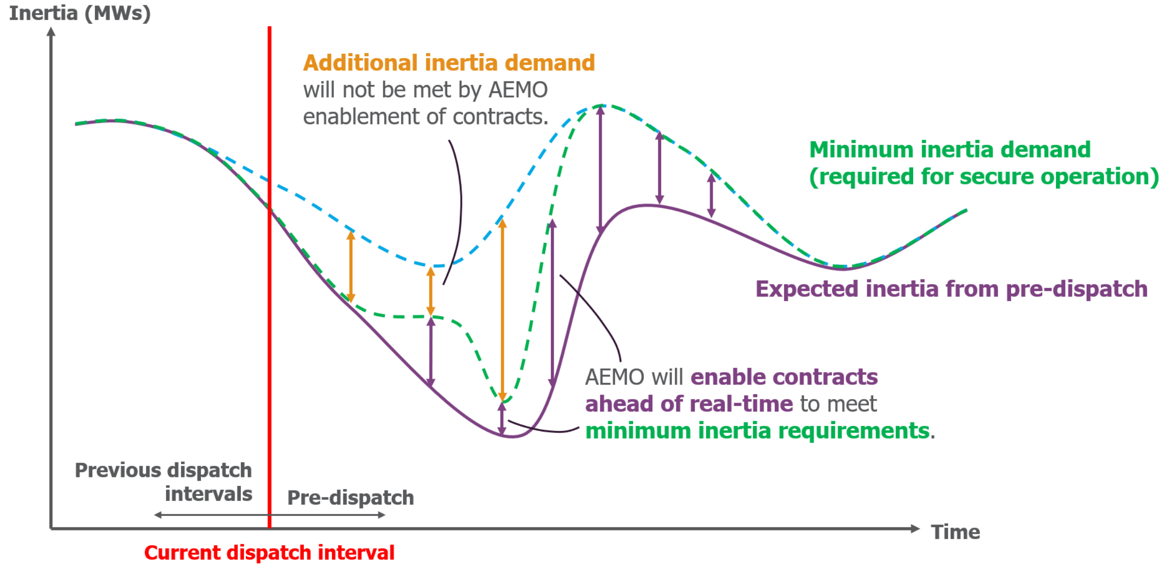
49 See clauses 4.4A.1 and 4.4A.4 in Schedule 5 of the ISF Rule.

parameters and financial structure of their contracts with generators and integrated resource providers.[50]

Through enablement of these contracts, and assuming that there are no unplanned outages or non-compliant behaviours, or under-estimation of actual requirements by AEMO, the minimum inertia requirements should always be met. This is because the TNSP obligations to make available required levels of inertia mean that there should be sufficient contracts with market participants and inertia available from synchronous condensers to meet minimum inertia requirements.

Figure 4.7 illustrates how AEMO enablement of contracts would meet minimum inertia requirements but would not meet any additional inertia demand.

Figure 4.7: Relationship between AEMO enablement and minimum inertia demand



Source: AEMC
Note: This diagram is for illustrative purposes only and does not represent any intra-day inertia demand projections or forecasts.

50 AEMO, Provisional Security Enablement Procedure (Improving Security Frameworks), pp 6-12.

5 To assess operational procurement of inertia, we analysed inertia supply and demand and used a two-stage economic test

Box 2: Key points in this chapter

- The Commission engaged HoustonKemp to provide advice on the economic characteristics of inertia, both for minimum and additional inertia demand.
- HoustonKemp estimated both the demand and supply of inertia using:
  - AEMO publications on inertia requirements and its methodologies
  - the availability of synchronous condensers, and different scenarios for their entry
  - cost assumptions on inertia provided by synchronous and asynchronous plant.
- It devised a two-stage economic test to assess operational procurement of inertia:
  - Stage 1 — determining the suitability of minimum or additional inertia for operational procurement
  - Stage 2 — quantifying the benefits of operationally procuring minimum or additional inertia.
- HoustonKemp used various simplifying assumptions to reflect the illustrative scenario for operational procurement for inertia, such as:
  - assuming that inertia requirements are global or regional
  - considering synchronous condenser investment and entry may be slower or later than anticipated
  - estimating the benefits of operational procurement based on marginal costs of providing inertia, which may be below market prices.

5.1 The Commission engaged an economic consultant and sought input from a Technical Working Group (TWG)

The Commission engaged HoustonKemp, an economic consultancy, to support the Commission's analysis of operational procurement for inertia.

HoustonKemp was tasked with evaluating the economic case for different market arrangements for inertia. This involved:

- assessing inertia supply and demand characteristics
- developing an economic framework and principles to assess the potential benefits of operational procurement of different levels of inertia.

To ensure the analysis was robust, the Commission and HoustonKemp sought input from the TWG at key stages of the economic assessment process. The TWG established for this rule change provided feedback on the methodology, assumptions, and inputs for the economic analysis.

Feedback from the TWG was used to refine the economic assessment approach, update inputs and address practical considerations raised by TWG members.

5.2 The Commission sought advice on the demand and supply characteristics of inertia

The Commission sought advice from HoustonKemp to analyse the underlying factors influencing inertia demand and supply, providing a foundation for evaluating potential market arrangements.

Assumptions about inertia demand were informed by AEMO's inertia requirements methodology and historical and anticipated system performance.[51]

In its assessment of the supply characteristics of inertia, HoustonKemp estimated:

- the availability of synchronous generators
- different scenarios for synchronous condenser entry
- the costs of a wide range of inertia-providing technologies, such as batteries and synchronous condensers.

HoustonKemp's findings, outlined in more detail in chapter 6 and chapter 7, underpinned the Commission's consideration of the suitability and potential economic benefits of the operational procurement of inertia as outlined in chapter 8.

5.3 The Commission considered the findings from a two-stage economic test

The Commission considered the findings of a two-stage economic test developed by HoustonKemp to evaluate the suitability and potential benefits of operational procurement for inertia.

This test was designed as a 'hurdle' test, providing a structured approach to assess whether operational procurement for inertia could deliver economic benefits compared to the existing long-term procurement framework.

5.3.1 Stage one — testing the economic characteristics of minimum and additional inertia for suitability for operational procurement

The test included two stages. In the first stage, HoustonKemp assessed whether minimum and additional inertia possess the economic characteristics that are suitable for efficient operational procurement mechanisms, such as a spot market. The analysis focused on the following key characteristics:

- **The nature of the service**: operational procurement is more effective for well-defined services that are unlikely to change over time. Services with stable and clearly defined technical attributes are better suited to spot market procurement.
- **Opportunities for efficiency gains**: operational procurement can enable the optimisation of service provision by selecting the optimal mix of technologies, driving cost reductions, and encouraging innovation in the delivery of services.
- **Economic consequences of supply and demand imbalances**: operational procurement works best for services that can be rationed. Services with high costs of oversupply or undersupply may face challenges in operational procurement.

51 This includes AEMO's Inertia Requirements Methodology from 2018, its 2023 Inertia Report, 2024 Inertia Report and its Draft Inertia Requirements Methodology for 2024.

- **The need for investment certainty**: operational procurement is more effective where investment certainty is less critical. Services with high capital requirements or long investment horizons may align better with long-term contracts than with spot markets.
- **Competitive factors**: operational procurement needs competition to drive efficiency.

If either minimum or additional inertia fails to pass the first stage, or 'hurdle,' this would mean that such a level of inertia is not suitable for operational procurement. Section 7.1 and section 7.2 outline the findings of the hurdle test for minimum inertia and additional inertia respectively.

The Commission considers that this test creates a reasonable 'hurdle' for deciding whether to further investigate whether minimum and additional inertia are suitable for operational procurement approaches.

5.3.2 Stage two — identifying and quantifying potential benefits of operational procurement

In the second stage (if the hurdle test is passed), the test estimates the maximum potential benefits of operational procurement of inertia, focusing on benefits relative to the existing inertia framework.

As outlined in section 5.3.1, the findings from HoustonKemp's first-stage 'hurdle' test applied to minimum inertia suggests that minimum inertia does not have suitable characteristics for efficient operational procurement.

Thus, HoustonKemp's benefits assessment framework for the second stage of the economic test was focused primarily on identifying potential benefit streams for additional inertia. These include:

- avoided costs of fast frequency response procured through the 1-second FCAS markets
- avoided costs of constraining down the output of the largest generating unit
- the cost benefits gained from relieving binding constraints with inertia terms, which may allow for cheaper generation or interconnector flows to be dispatched.

However, HoustonKemp also identified the opportunity to leverage an operational procurement mechanism introduced for additional inertia to address operational shortfalls in the minimum inertia requirements, which are represented by avoided costs of AEMO issuing directions to synchronous generators to address inertia shortfalls.[52]

The second stage also involved estimating the costs of implementing and operating a spot market for inertia. These include the upfront costs of designing and implementing the market, the annual costs of administration, and the costs incurred by market participants to participate.HoustonKemp quantified these costs in 2024-dollar terms, applying a seven percent discount rate to calculate net present value. The Commission discusses this estimate and our views on implementation costs in chapter 8. In summary, we note that these estimates were developed by HoustonKemp. We have asked AEMO to provide us with their views on implementation costs to incorporate into our future assessments.

5.4 The analysis adopted assumptions that reflect an illustrative scenario for operational procurement of inertia

In undertaking an economic assessment on operational procurement of inertia, the Commission adopted assumptions that reflected an illustrative scenario to determine whether there is an economic case for further exploring operational procurement options.

52 However, as described in section 4.4.2, if there are no unplanned outages, non-compliant behaviours or AEMO under-estimation of requirements, there should be no operational shortfall of minimum inertia requirements.

The assumptions adopted by the Commission and HoustonKemp were intended to capture all available benefits of operational procurement. These included:

- making simplifying assumptions about the role of inertia and its technical characteristics (for example, assuming inertia requirements are global or regional, rather than locational, by disregarding inertia's role in damping oscillations)
- considering various scenarios for synchronous condenser investment
- not necessarily requiring all the preferred characteristics of the hurdle test to be met to proceed to stage two of assessment
- estimating benefits of operational procurement based on the marginal costs of inertia which may be below market prices in many trading intervals.

The Commission recognised that these assumptions might not reflect the full complexity of operational procurement or the challenges associated with implementation. However, this is intended to test whether operational procurement, including a spot market, can demonstrate clear and material benefits under simplifying assumptions. If the economic case holds under these conditions, it provides a reasonable starting point for further considering what market design and implementation options are available and how they would affect the realisation of the estimated benefits.

6 Inertia demand and supply characteristics underpin the economic analysis

Box 3: Key points in this chapter

- The demand and supply of inertia will change as the NEM transitions to a consumer-focused net zero energy system.
- The retirement of large synchronous generators will decrease inertia supply in the NEM over time, but is also likely to decrease inertia demand. This is because inverter-based plant have a much higher ability to withstand high rates of change of frequency than synchronous generators.
- It is possible that larger contingencies are present in the future NEM, which could increase demand. This depends on how the projects are commissioned and connected to the network.
- Future supply of inertia depends on:
  - the rate of synchronous generator retirement
  - the entry of synchronous condensers
  - the entry of other technologies, such as batteries or conversions from synchronous generators to condensers.
- The number of synchronous condensers in the NEM is likely to increase in coming years, as TNSPs begin to meet their obligations under the new system strength framework and amended inertia framework. Many of these synchronous condensers are likely to be installed with flywheels to provide inertia.
- If actual synchronous condenser commissioning is aligned with the investment currently indicated in TNSP RIT-T documents, then these synchronous condensers may provide significant inertia in the NEM continuously. Along with average synchronous generator availability, inertia provided by synchronous condensers this may exceed our estimate of minimum inertia demand. However, exceeding minimum inertia demand is not certain because:
  - the investment in synchronous condensers is uncertain, and
  - synchronous generator inertia provision is based on average capacity factors. If synchronous generation is offline for maintenance or due to low prices, the mainland NEM could see lower inertia supply sooner
  - the provision of synthetic inertia by inverter-based plant is not certain
- The NEM also has a significant supply of inertia from load-side sources, with varying costs. The inertia provided by these sources is currently not reliably measured.

This chapter considers how system need for inertia (or 'minimum inertia demand') and supply of inertia from various sources is likely to change over time. These estimates and considerations underpin the analysis of procurement approaches in chapter 8.

6.1 The demand for inertia in the NEM will likely change

6.1.1 Minimum inertia demand can be estimated using AEMO's Inertia Report

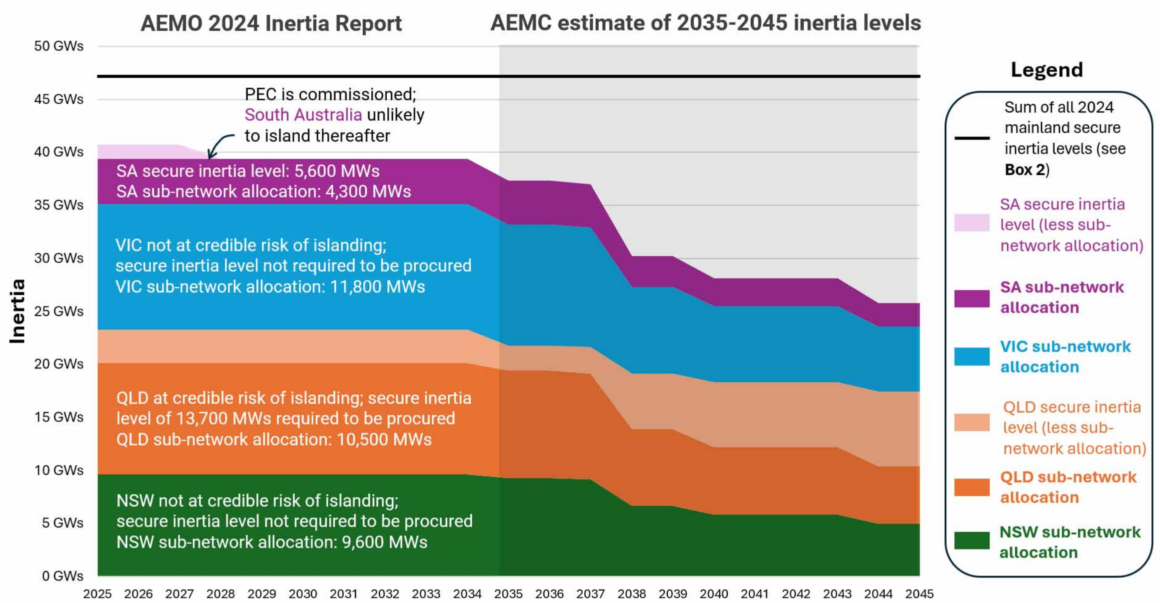
To estimate minimum demand for inertia in the NEM in planning timeframes, we can use AEMO's 2024 Inertia Report and consider how demand might change as the NEM transitions.

The AEMC has mapped AEMO's 2024 determination of minimum inertia requirements that must be procured by TNSPs for each NEM region, as shown in Figure 6.1. As explained in section 4.4, TNSPs must make available either the:

- regional sub-network allocation, for regions not at risk of islanding
- secure inertia level, for regions with a credible risk of islanding.

We have also estimated what these binding inertia requirements may be between 2035 and 2045 by using generator retirements based on the 2024 Integrated System Plan.

Figure 6.1: AEMC's estimate of binding inertia requirements based on AEMO's 2024 inertia report



Source: AEMC, using data from AEMO's 2024 Inertia Report.

Note: Our estimates are based on AEMO's forecast inertia demand to 2035. We extrapolated the inertia floors using the swing equation adjusted by the 2025-2035 estimates from AEMO.

The coloured areas in Figure 6.1 represent the binding inertia requirements for each mainland region until 2034, and then our estimates of the sub-network allocations for each region from 2035 to 2045. We have shown both the 'sub-network allocation' levels for each region (or their allocation of the inertia 'floor'), as well as the additional amounts that take a region up to its 'secure' level, where AEMO has determined that the region is at risk of islanding.

Our estimates of inertia requirements for 2035 to 2045 are based on the retirement dates of existing generators in AEMO's 2024 Integrated System Plan. The sub-network allocation estimates decrease from 2035, based on when the largest generating units retire as per the Integrated System Plan.

AEMO's determination of the binding minimum inertia requirements from 2027 to 2034 is **39,400 MWs**.[53] Our estimation of the minimum inertia requirements range from 37,350 MWs in 2035 to about 25,800 MWs in 2045.

We note that these are planning timeframe estimates that give an estimate of required inertia levels for a whole year. The real-time inertia demand will vary, depending on system conditions. We have only estimated the inertia requirements of the mainland NEM. Tasmania is not synchronised with the mainland, as it is connected only through high voltage direct current transmission.

Box 4: The binding inertia requirements are lower than the sum of all mainland secure levels, because not all regions are at risk of islanding

In Figure 6.1, we have included a horizontal line that represents the sum of all 2024 mainland secure inertia levels (equal to 47,200 MWs). This represents the total amount of inertia that would be needed across the mainland NEM if each region were required to be able to securely operate as an island.

However, as only Queensland and South Australia have a credible risk of islanding (and South Australia's risk only exists prior to the commissioning of Project Energy Connect (PEC)), AEMO's determination of binding inertia requirements for TNSPs until December 2034 is lower than the sum of secure inertia levels. This is because interconnected operation means that inertia can be shared and transferred between NEM regions.

The sum of the current secure inertia levels can be used as a conservative estimate of minimum demand for inertia, as a kind of 'upper bound' for minimum inertia demand in the future. If credible contingency sizes in 2035-2045 remain at present-day levels or slightly increase, then future binding inertia requirements on TNSPs are likely to be somewhere between the coloured area (that is, the sum of the current binding requirements) and the black line (the sum of the current secure levels) in Figure 6.1. See section 6.1.4 for more discussion on future contingency sizes.

6.1.2 Additional inertia demand depends on costs and trade-offs

As explained in section 4.3.2, we define additional inertia as any inertia above minimum inertia requirements that reduces overall system costs.

We have not estimated specific figures for additional inertia 'demand' because this depends on costs and benefits in operational timeframes. However, the findings in section 7.2 estimate the potential benefits of procuring this additional inertia.

6.1.3 It is highly likely that synchronous generator retirements will decrease inertia demand

A primary driver for minimum inertia demand is related to the needs of large generating units. Most of the largest generating units in the NEM are currently coal or gas power plants. These units have a lower ability to withstand high rates of changes in frequency, whereas inverter-based plant have a much higher withstand or ride-through capability to high rates of change of frequency. Between now and 2050, most of these large generating units will retire.

53 This is the sum of the sub-network allocation levels in NSW, Victoria & South Australia, and the secure inertia level in Queensland (see Figure 6.1). Prior to the commissioning of Project Energy Connect (PEC), South Australia has a credible risk of islanding, and so its secure level would be part of the minimum inertia requirements. Including South Australia's secure inertia level would bring the total minimum inertia requirement to 40,700 MWs. TNSPs are required to make available their required amount of inertia from 1 December 2027 — see NER, 5.20B.2(g).

If the rate of change of frequency limit for the mainland NEM is modified by the Reliability Panel in the future due to the higher withstand capability of the future generation mix, minimum inertia demand may significantly decrease.

6.1.4 It is possible that there will be larger contingencies in the future NEM that may increase minimum inertia demand

The NEM's minimum inertia requirements are heavily influenced by the size of the largest credible generation and load contingencies. Currently, the largest credible generation contingency in the NEM is Kogan Creek, at 744 MW.

It is possible that larger credible contingency sizes could arise in the NEM in the future. For example, large renewable energy zones or offshore wind farms may create large credible contingencies, depending on their connection to the transmission network.

However, these large projects may be commissioned with special protection schemes to lower their effective contingency size, or may not be classified as credible contingencies depending on the nature and topology of their connection with the network. 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. [54] It is possible that future large projects in the mainland could also use emergency frequency control schemes to reduce their effective contingency size.

On the other hand, it is also possible that there are future changes to how credible and non-credible contingencies are defined with the transitioning system, and that large events that were previously non-credible become credible.

> **Question 1: Future credible contingency size in the NEM**
>
> Do stakeholders expect that the NEM will have smaller or larger credible contingencies in the future? What will drive trends in contingency sizes?

6.2 The supply of inertia in the NEM is changing

6.2.1 Future supply of synchronous inertia depends on synchronous generator retirements, the entry of synchronous condensers and the uptake of grid forming inverters

Historically, the main source of inertia has been baseload synchronous generation. Inertia is a positive externality[55] of synchronous generation. When a synchronous generator is synchronised (that is, any time it is dispatched), it is producing its maximum possible inertia. This was, and still is, the main source of inertia in the NEM.

Synchronous generator retirements

As synchronous generation exits, both in specific operational periods and over time, we will see lower levels of synchronous inertia in the NEM — Figure 6.2 illustrates this. The light blue area shows the average inertia expected from synchronous generation in operational timeframes[56] (that is, adjusted for expected reduction in time synchronised with increasing inverter based

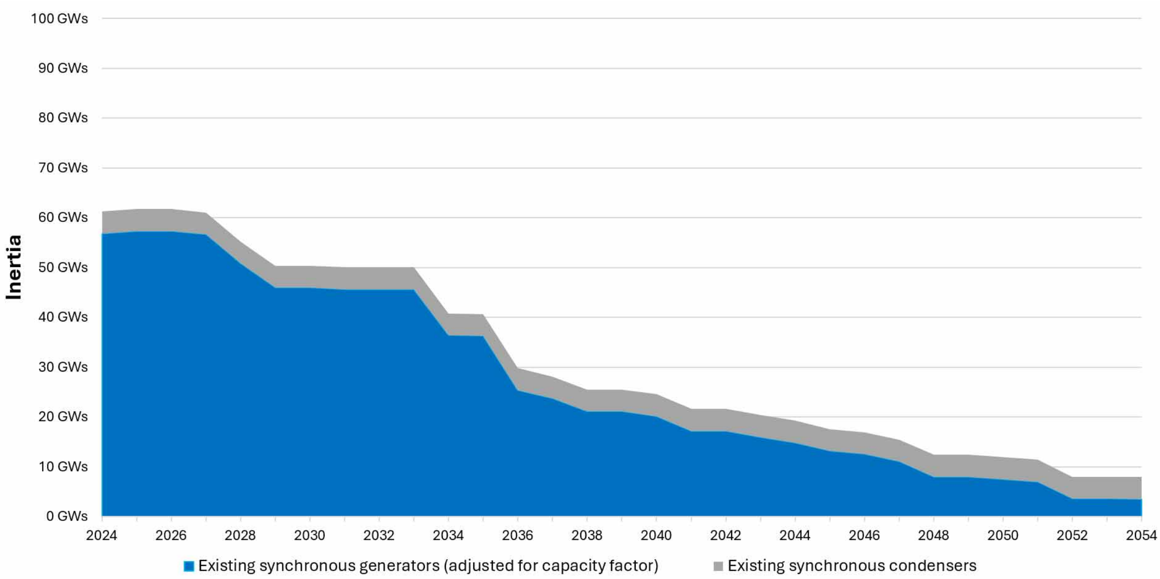
54 Reliability Panel, 2019, Review of the Frequency operating standard — stage two, pp 12-17. https://www.aemc.gov.au/sites/default/files/2019-12/Review%20of%20the%20Frequency%20operating%20standard%20-%20Stage%202%20Final%20determination%20-%20TYPO%20corrected%2019DEC2019.PDF

55 That is, an unavoidable byproduct that provides something of value.

56 The average inertia is calculated as the time-weighted average of inertia produced from synchronous generation over the year.

generation). In many intervals (for example on clear days in spring and autumn) the supply of inertia from synchronous generation will be below the average. The grey area shows the inertia provided by the four high-inertia synchronous condensers already active in South Australia.

Figure 6.2: Expected inertia from existing synchronous inertia sources



Source: HoustonKemp's analysis.

Entry of synchronous condensers

Synchronous condensers can also provide inertia, along with system strength. A synchronous condenser without a flywheel provides some inertia.[57] If a flywheel is attached, the synchronous condenser provides significantly more inertia.

There are already four high inertia synchronous condensers in the NEM, commissioned by ElectraNet. Each of these provide 1,100 MWs of inertia — this is shown as the grey area in Figure 6.2. Synchronous condensers are always 'on' (barring any forced outages or scheduled maintenance) and so would always supply a constant amount of inertia to the NEM.

The number of synchronous condensers in the NEM is likely to increase in coming years, as TNSPs begin to meet their obligations under the new system strength framework (obligations begin December 2025) and amended inertia framework put in place by the ISF (obligations begin December 2027). Under the ISF, TNSPs will co-optimise their investments in system strength and inertia. TNSPs have already started to identify preferred options for meeting these obligations in the initial years, with Transgrid and Powerlink recently releasing PADRs for system strength.[58]

Even though TNSPs have begun to identify investment options, the forecast future inertia from synchronous condensers is uncertain. TNSPs may:

- have difficulty procuring sufficient synchronous condensers on the timeline they currently forecast

57 Synchronous condensers without flywheels typically have an inertia constant of at least 1 second (see section 4.2.1). Therefore, a 125 MVA synchronous condenser would provide at least 125 MWs of inertia.

58 Transgrid, *Meeting system strength requirements in NSW*, RIT-T Project Assessment Draft Report, 17 June 2024; Powerlink Queensland, *Addressing System Strength Requirements in Queensland from December 2025*, Project Assessment Draft Report, November 2024.

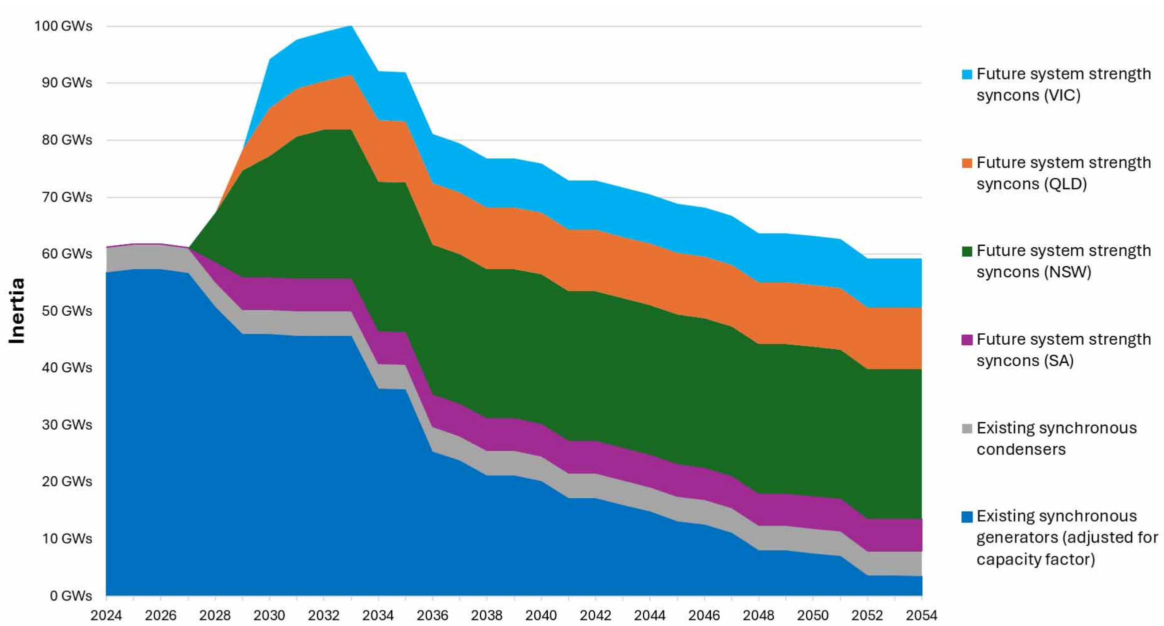
- decide to procure system strength services from other sources, such as from battery energy storage systems
- decide to install more synchronous condensers than indicated in these estimates as they develop their PADRs and incorporate the new inertia requirements from 2027
- install synchronous condensers for system strength that provide significantly less inertia (e.g. from not adding a flywheel to the synchronous condensers).

Nevertheless, it is useful to look at the range of inertia levels that could be provided by synchronous condensers — especially those that are in place within the next few years.

According to the most recent Transgrid PADR,[59] Powerlink PADR,[60] ElectraNet PSCR,[61] and AEMO's PSCR for Victoria[62], mainland TNSPs have identified that their preferred portfolios for system strength include 36 additional synchronous condensers over the next nine years. Figure 6.2 below shows the potential inertia provided if all of these synchronous condensers are built (this would be continuously provided, barring an outage), in addition to existing synchronous condensers (this is an average level of inertia over time, as described earlier in this section). Figure 6.2 also shows the average inertia from existing synchronous generation in the light blue area from Figure 6.2 above.

Together, these look to exceed both the binding minimum inertia requirements between 2027-2034, which total to 39,400 MWs, and the sum of all 2024 secure inertia levels of 47,200 MWs (both shown in Figure 6.1), for the forward period to 2054. We note that the synchronous generator availability will, at certain times, be below average (that is, more synchronous generation may be offline).

Figure 6.3: Potential inertia supply from synchronous condensers for system strength



Source: HoustonKemp analysis

59 Transgrid, *Meeting system strength requirements in NSW*, RIT-T Project Assessment Draft Report, 17 June 2024, p 5.

60 Powerlink Queensland, *Addressing System Strength Requirements in Queensland from December 2025*, Project Assessment Draft Report, November 2024, p 18.

61 ElectraNet, *System Strength Requirements in SA*, Project Specification Consultation Report, November 2023, p 57.

62 AEMO Victoria Planning, *Victorian System Strength Requirement*,Project Specification Consultation Report, July 2023, pp 17-19.

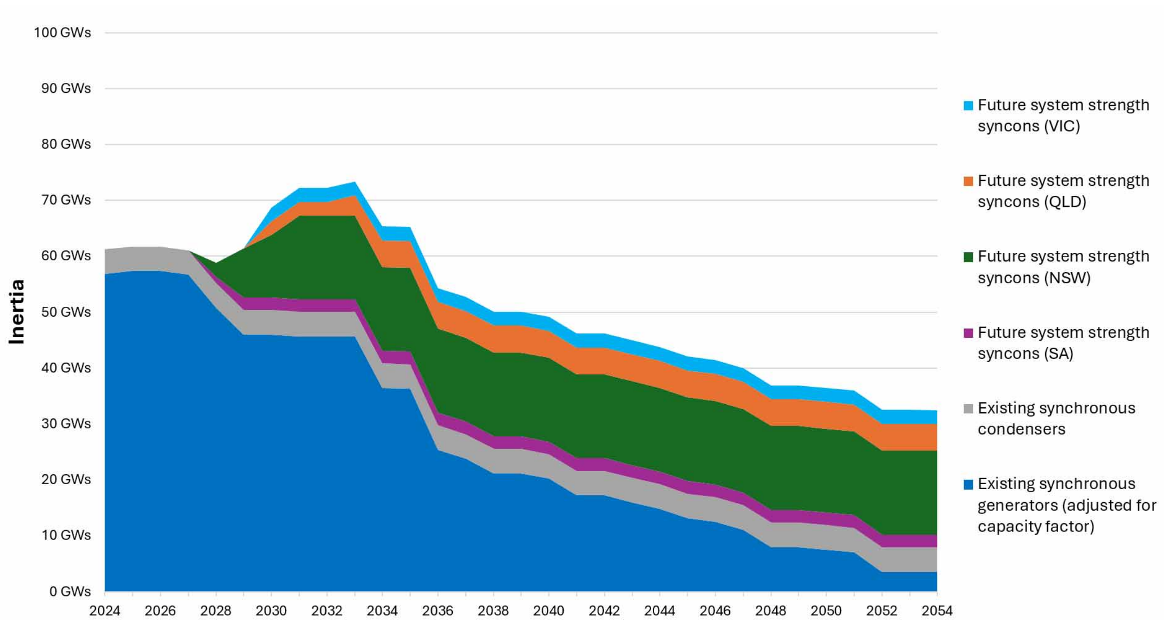
HoustonKemp also estimated inertia with minimal investment in synchronous condensers. This scenario is based on:

- the credible option in the TransGrid and Powerlink PADRs with the fewest synchronous condensers in NSW/ACT and Queensland, and
- two (additional) synchronous condensers for each Victoria, South Australia and the Central West Orana Renewable Energy Zones.

This scenario could occur due to the decreasing costs of battery energy storage systems, making them more competitive with synchronous condensers for system strength and other system services or AER decisions.

In this scenario, shown below in Figure 6.4, average inertia from synchronous sources would fall below the current aggregate secure inertia level of 47,200 MWs from about 2041 — noting that this is a conservative estimate of minimum inertia demand, as explained in Box 4. However, inertia levels would remain above AEMO's determination (and the AEMC's estimation) of binding inertia requirements shown in Figure 6.1 and described in section 6.1.1, which range from 39,400 MWs in 2034 to 25,800 MWs in 2045.

Figure 6.4: Average inertia available if only minimal TNSP procurement of synchronous condensers goes ahead



Source: HoustonKemp analysis

Question 2: Future estimates of synchronous condensers

Do stakeholders expect that synchronous condensers for system strength are likely to provide most of the NEM's minimum inertia needs? What would influence the uptake of synchronous condensers in the NEM?

Provision of inertia from grid-forming inverters

The provision of inertia in the NEM is evolving as the system transitions from traditional synchronous generation to renewable energy sources. Grid-forming inverters, which provide synthetic inertia through advanced control systems, are emerging as a promising alternative to synchronous sources of inertia. Unlike traditional sources, grid-forming inverters do not rely on physical rotating mass but can emulate inertial responses dynamically.

Currently, the role of grid-forming inverters in maintaining system security is limited and still evolving. However, advancements in control systems, measurement techniques, and operational experience are gradually expanding their role in maintaining system security. A notable advantage of these inverters is their flexibility, as they can provide synthetic inertia while charging, discharging, or idle. This capability enables them to co-optimise with other services, such as FFR and energy storage, further enhancing their value in the evolving energy landscape.

The future role of grid-forming inverters will depend on several factors, including cost trajectories, regulatory frameworks, and the pace of technological advancements. Recent studies project significant cost reductions in battery energy storage systems by 2030, which will likely enhance the economic viability of grid-forming inverters for inertia provision. These inverters are also being considered as part of system strength solutions by TNSPs, potentially expanding their deployment in the NEM.

However, key uncertainties remain, including the operational challenges of maintaining sufficient headroom or footroom for effective inertial responses and integrating these resources into real-time market and dispatch systems. Stakeholder feedback will be critical in refining approaches to incorporating grid-forming inverters into the NEM's inertia framework and ensuring their contributions align with system security needs.

Question 3: Future role of grid-forming inverters

What do stakeholders consider to be the potential role of grid-forming inverters in future inertia provision ? We would be interested in thoughts on technical and economic challenges, opportunities for co-optimisation with other system services, and the conditions necessary for scaling their deployment effectively.

6.2.2 Inertia can be supplied by diverse technologies which have different cost structures

As discussed in section 4.2, there are four main sources of inertia:

- Synchronous generation — like coal, gas and hydroelectric power plants
- Synchronous condensers — both with and without flywheels
- Inverter based resources — like battery energy storage systems
- Synchronous loads — such as industrial loads.

HoustonKemp provided the AEMC with estimates of the costs of different (non-load) sources of inertia (see Table 6.1 below). These were informed by AEMO's 2024 ISP Inputs and Assumptions for synchronous generation, and research from the Australian Renewable Energy Agency, TNSP PADRs and PSCRs, and the CSIRO GenCost Report. More detailed information on how HoustonKemp developed these estimates is presented in Appendix 2.2 of their Report.

Table 6.1: Estimated costs of inertia supply

<table>
<tr><th colspan="2">Inertia source</th><th>Fixed cost ($/MWs/year)</th><th>Variable cost ($/MWs/hour)</th><th>Emissions cost ($/MWs/hour)</th></tr>
<tr><td colspan="5">Synchronous generation</td></tr>
<tr><td colspan="2">Existing synchronised generation</td><td>$0</td><td>$0</td><td>$0</td></tr>
<tr><td colspan="2">Earlier or prolonged dispatch of existing synchronised generation</td><td>$0</td><td>$0.30 — $1.10</td><td>$1 — $9</td></tr>
<tr><td colspan="2">Delay shutdown of existing synchronised generation (current, expected to increase)</td><td>$700 — $9,000</td><td>$0.30 — $1.10</td><td>$1 — $9</td></tr>
<tr><td colspan="5">Synchronous condensers</td></tr>
<tr><td colspan="2">Add flywheel to system strength syncon during construction</td><td>$170</td><td>Very low incremental</td><td>Very low</td></tr>
<tr><td colspan="2">Retrofit flywheel to existing syncon (new or repurposed generator)</td><td>Uncertain, significantly higher than $170</td><td>Very low incremental</td><td>Very low</td></tr>
<tr><td rowspan="2">Build syncon for inertia, with a flywheel</td><td>New</td><td>$7,600</td><td rowspan="2">$0.20 — $0.50
(assuming electricity consumption equal to 1.5% of syncon rating)</td><td>Low</td></tr>
<tr><td>Repurposed</td><td>$1,900 - $4,900</td><td>Low</td></tr>
<tr><td colspan="5">Synthetic inertia</td></tr>
<tr><td rowspan="2">Synthetic inertia from IBRs</td><td>1hr, 2024</td><td>$0 — $806</td><td>$0 — $6 (avg: $0.02)</td><td>$0</td></tr>
<tr><td>1hr, 2030</td><td>$0 — $488</td><td>$0 — $6 (avg: $0.02)</td><td>$0</td></tr>
</table>

Source: HoustonKemp analysis

As shown in Table 6.1 above, we expect the costs of providing synthetic inertia to fall in the future. This reflects expectations that the costs of battery energy storage systems will fall in the coming decades. The most recent CSIRO 'GenCost' report expects significant decreases in the capital costs of 2-hour batteries from around $700/kWh to between $300/kWh and $400/kWh by 2030.[63] The United States National Renewable Energy Laboratory similarly forecasts 18% to 50% reduction in 4-hour battery capital costs by 2030.[64]

63 CSIRO, *GenCost 2023-24*, Final report, May 2024, pp 57-58.

64 National Renewable Energy Laboratory, *Cost Projections for Utility-Scale Battery Storage: 2023 Update*, June 2023, p iv.

6.2.3 Load-side inertia is a key uncertainty in supply

Synchronous loads are another, potentially substantial, source of inertia. The Australian Renewable Energy Agency commissioned Reactive Technologies, partnering with the University of Melbourne and AEMO to measure inertia in real time. They found that on average there was a range of 14 GWs to 52 GWs of inertia more than the theoretical inertia from generation sources.[65] Most of this comes from load.[66] The future trajectory of load-side inertia is unclear with two countervailing trends:

1. decreasing use of synchronous motors will reduce load-side inertia, and
2. increasing demand for electricity and more distribution connected inverter based resources, including household batteries, which could supply load-side inertia.

We note that traditional load-side inertia, such as from synchronous motors, is similar to synchronous generation in that inertia is a positive externality of customers' consumption of electricity.

AEMO does not currently measure inertia in real time, and cannot currently estimate the inertial contribution from individual (non-scheduled) customers. Both of these factors make it difficult for load-side inertia to participate in existing inertia procurement or any future inertia procurement model or market. Under the ISF, TNSPs may procure inertia from scheduled loads.[67]

We consider that load-side inertia is an important source of inertia supply and should factor into inertia procurement decisions.

Question 4: Future inertia supply and costs

Do stakeholders have any further information about the fixed and variable cost estimates of future inertia supply?

65 Evaluation of Reactive Technologies Inertia Measurement and Techno-economic Modelling, The University of Melbourne (Report prepared for Reactive Technologies, System Inertia Measurement Demonstration Project), p 26.

66 In the study, Reactive Technology assumes that it is all load side inertia, but notes it could in part be due to inaccurate data from online generators and synchronous condensers, incorrect inertia constants for generators or other reasons.

67 TNSPs can only procure inertia from registered market participants — see NER, clause 5.20B.4(d)-(e).

7 The findings of the two-stage economic analysis

Box 5: Key points in this chapter

- To assess operational procurement of inertia, we applied the two-stage economic test described in chapter 5 to both minimum and additional inertia.
- We found that minimum inertia may have some of the economic characteristics that would support operational procurement. However, there are very high costs of undersupply of minimum inertia, given that this can lead to an insecure system.
- Therefore, we consider that long-term procurement is currently the best procurement mechanism to ensure that minimum inertia needs are met in the NEM.
- Additional inertia does not have the same risks of undersupply. We found that additional inertia has, or is likely to have, the economic characteristics to support operational procurement.
- HoustonKemp modelled the potential benefits of procuring additional inertia. It found that, as an upper estimate, there may be:
  - benefits of $7.7 million in 2024 to $30 million in 2033 due to co-optimising inertia and fast frequency response
  - benefits ranging from $2 to $20 per MWs of additional inertia in South Australia, and from $5 to $355 per MWs of additional inertia in Tasmania during low inertia periods due to alleviating RoCoF constraints.
- Given these estimated benefits, the Commission considers there is a case to further look into models for operational procurement of additional inertia. We consider that further investigation of the benefits, costs and implementation considerations (discussed in chapter 8) is necessary before we deliver our draft determination.
- HoustonKemp also modelled potential benefits from using operational procurement to 'top-up' inertia to minimum levels:
  - benefits ranging from $0.7 million to $7.2 million per year due to alleviating constraints on contingency size; and
  - benefits averaging $1.8 million per direction avoided, where directions would otherwise be used to meet minimum levels of inertia for security.
- Given these benefits estimates, we consider that if operational procurement for additional inertia is implemented, it should be an option available to AEMO to help meet minimum inertia needs in operational timeframes in cases where this can reduce system costs.

7.1 Long-term procurement is the best method for procuring minimum inertia today

7.1.1 Minimum inertia has some, but not all, of the economic characteristics that support operational procurement

Applying the first stage of the hurdle test to minimum inertia levels, we have found that minimum inertia may have some of the economic characteristics that would support operational procurement (Table 7.1 below shows the results of the Commission's assessment against the economic factors in the hurdle test. This draws from HoustonKemp's findings in Chapter 4 of its report). However, we consider that in the near term, the main impediment to operational procurement of minimum inertia is the high costs and risks of undersupply.

Table 7.1: Stage-one (the hurdle test) assessment for minimum levels of inertia

What economic characteristic support spot markets?	Do minimum levels of inertia have this characteristic?
The good/service can be well-defined.	**Yes:** Inertia is capable of being well defined and is sufficiently homogeneous that different inertia sources can be substituted. There may be some challenges in defining aspects of inertia other than rate of change of frequency service, but we consider that these are manageable.
There are either low upfront costs or mechanisms to manage investment risks.	**Unlikely:** The capital expenditure required to enter the market to supply minimum levels of inertia are likely high. The electricity system must always meet minimum inertia quantities. This requires assets to always be available to provide inertia. This will likely require investment dedicated to inertia, such as synchronous condensers with flywheels or reserving head- and foot-room in a battery energy storage system. However, we note that this is not definitive. Historically with high levels of synchronous generation there has been no need to invest specifically for inertia and in the future, falling costs and growing capacity of battery energy storage systems or innovations in converting synchronous generators to synchronous condensers may meaningfully reduce costs of entry. We note there are currently no secondary markets to help entrants mange the costs of entry. We note that these markets could develop in the future.
There are opportunities for efficiencies	**Maybe:** The opportunities for operational procurement to identify the least cost mixture of sources for minimum inertia are highly dependent on future system strength investments or other demand for complementary system services. • If all currently proposed synchronous condensers with flywheels are installed in the coming years, they could meet all the NEM's minimum inertia need at nearly no additional cost above only providing complementary system strength and other services. • If TNSPs do not build the proposed synchronous condensers with flywheels, we are likely to need a mixture of technologies to meet inertia needs, creating greater opportunities for operational procurement to minimise cost and incentivise innovation.
There are low costs of undersupply and high costs of oversupply.	**No:** The costs of undersupply of inertia are very high because if there is not sufficient inertia in the power system then the security of the system is at risk, which could lead to customers bearing the high costs associated with load shedding or even, at an extreme, large scale blackouts.

What economic characteristic support spot markets?	Do minimum levels of inertia have this characteristic?
	Over-procuring inertia through long-term contracting imposes increased costs on all consumers, by • over-investing in TNSP capital or operating expenditure, • increasing emissions from extending the life of synchronous generators, and/or • increasing wholesale prices from reserving unused headroom in battery energy storage systems. However, we consider that the potential costs of undersupply of minimum inertia are significantly higher (in relative terms) than the potential costs of oversupply. In other words, the costs and risks are not symmetrical — a relatively small undersupply could have the very large costs of an insecure system, whereas the same level of oversupply does not threaten security and has the relatively smaller costs of procuring more than needed. Of course, the relativities depend on the exact level of oversupply — a significant oversupply would have more significant costs.
There is likely to be liquidity/competitive pressure.	**Maybe:** We consider that there is a risk of substantial market power with operational procurement of inertia. The high investment costs and inability for some synchronous inertia sources to enter quickly, may create opportunities for participants to use market power to increase prices. This may be mitigated by competitive constraints created from resources, such as battery energy storage systems, participating in operational procurement of inertia alongside wholesale and ancillary services.

Source: AEMC, based on HoustonKemp analysis.

7.1.2 We consider that operational procurement is not currently suitable as the primary mechanism for meeting minimum inertia levels

Minimum inertia is needed for system security. If the NEM loses a large enough generation source and there is insufficient inertia, the frequency losses may not be recoverable. This could lead to:

- under-frequency load shedding, and
- system-wide or region-wide blackouts.

In 2016, we saw a South Australia-wide black out, with most electricity restored within 8 hours. It is difficult to estimate the economic costs of large-scale blackouts, however one estimate put the cost at $367 million to businesses alone.[68] Wider and longer duration outages could impose far greater costs on Australia.

Due to the high costs and significant risks of undersupply, HoustonKemp concluded that operational procurement is not currently suitable as the primary mechanism for meeting minimum inertia requirements and did not move to the second stage of the economic assessment for the minimum level of inertia (which estimates the benefits of operational procurement of inertia). The Commission agrees with this conclusion.

68 Business SA, Blackout survey results.

7.1.3 Long-term procurement frameworks are currently better suited to minimum inertia as they minimise undersupply risks

To minimise these undersupply risks, the Commission considers that long-term procurement frameworks are currently the most suitable procurement mechanism for minimum inertia levels. In general, long-term procurement frameworks work as follows:

- a required level of inertia for procurement is set by AEMO.
- a party (currently TNSPs) is required to ensure availability of this required level of inertia in operational timeframes through a combination of investment and long-term contracts
- if necessary, AEMO enables the contracted inertia in real time to meet minimum inertia levels.

The level of inertia that TNSPs must procure through long-term arrangements and the real-time minimum inertia requirements are not the same. As noted in section 4.3.1 the real-time minimum inertia requirement depends on system conditions and dispatch outcomes in any given interval.

Given the costs of both over- and under-procurement, it is important to set the required procurement level at a level which appropriately balances risks and costs. If the level is conservatively high, consumers will pay for inertia that is not needed. If it is very low, consumers may pay for the results of an insecure system.

AEMO is currently required to publish its methodology for determining inertia requirements and an inertia report each year determining its forecast of those requirements for each NEM region.[69] The inertia framework, and AEMO's inertia requirements methodology, set some parameters for how risks are currently taken into account when AEMO sets the required inertia levels:

- the definition of a 'satisfactory' and 'secure' system (which draw in the concept of contingencies) underpin the determination of minimum levels
- the frequency operating standard and any other factors AEMO considers relevant help determine minimum inertia requirements for interconnected mainland NEM operation
- the risk of a region 'islanding' determines whether higher inertia procurement requirements apply.

It is also important that real-time enablement of inertia to meet the minimum level balances risks with incurring unnecessary costs through over-enablement. The more accurately AEMO can determine real-time requirements, and the closer enablement can occur, the better the risks and costs can be managed. AEMO will be required to detail how it determines enablement in the Security Enablement Procedures. These procedures were introduced by the ISF Rule and are due to be in place by 31 August 2025.[70]

To keep costs for consumers as low as practicable, it also is important that the procurer (TNSP) faces strong incentives to maximise efficiency by ensuring it:

- secures the least-cost portfolio of supply, and
- allows for flexibility as technology changes (e.g. not locking investments into a TNSP's regulated asset base for decades).

This requires TNSPs to compare the cost of options over the right timeframe, to allow for changing least-cost portfolios. The AER's oversight is critical to ensuring TNSPs make prudent and efficient investments for the supply of system security services, including inertia.

69 AEMO, Inertia requirements methodology.

70 NER, clause 11.168.2.

We note that our conclusion relates to the risks of inertia undersupply given the current NEM composition and current technical understanding. With increasing knowledge about how to operate the transitioning system and the capabilities of inverter based resources, and with increased supply of synthetic inertia in the NEM, AEMO may become more confident about relying on operational procurement to meet minimum levels. If we introduce operational procurement for additional inertia (as discussed in section 7.2 and chapter 8), we are likely to learn more about the economic characteristics of inertia, and we could discover:

- the costs of entry and whether secondary markets emerge
- more about the scope for efficiency in identifying the least cost supply of inertia
- the depth of the market and whether the risk of inertia shortfall remains, and
- the liquidity of the market and level of competition.

This information could lead to a reduced reliance on longer-term procurement.

7.1.4 There may be benefits of some operational procurement to meet minimum levels, alongside longer-term contracting

Under the ISF Rule arrangements, TNSPs are required to contract for the full level of inertia requied to keep the system secure as determined by AEMO. We consider that the risks of undersupply means that this remains appropriate in the near term (noting the importance of robust setting of the required levels, as discussed in section 7.1.3).

In operational timeframes, if there is an undersupply of inertia below minimum levels, AEMO can currently enable these contracts or direct units online for inertia as a last resort.

As noted above, we do not consider that operational procurement is suitable as the primary mechanism for procuring minimum inertia at this time. However, if operational procurement were introduced for additional inertia (see section 7.2 and chapter 8 for a discussion of this option), we expect it could help reduce costs of procuring minimum inertia:

1. Long-term inertia contracts for minimum inertia will have enablement payments, where operational procurement for additional inertia could be a lower-cost way to meet these needs. This would benefit consumers by reducing overall costs of dispatch, and by creating competitive pressure to minimise the costs of enablement payments in contracts.
2. HoustonKemp's analysis found that the likely cost of an inertia direction is about $1.8 million per direction.[71] Where long-term contracting leads to a small undersupply in operational timeframes, such as due to unexpected plant outages, using operational procurement may avoid significant costs.

Therefore, should we recommend operational procurement for additional inertia, we consider that it should allow AEMO to procure minimum levels where that is efficient (as highlighted in the points above).

Question 5: Procurement mechanism to meet minimum inertia levels

Do stakeholders agree that long-term procurement models are currently most suitable to meet minimum levels — given the high cost to the system if minimum inertia requirements are not met?

71 In 2024 dollar terms (see section 5.2.4 of HoustonKemp's report for more detail on this estimate).

7.2 There may be a case for operational procurement for additional inertia

The Commission considers that additional inertia is likely to be suited to operational procurement, and there may be benefits in procuring additional inertia — as shown by HoustonKemp's estimates. We consider that further investigation of the benefits, costs and implementation considerations (discussed in chapter 8) is necessary before we deliver our draft determination.

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

We consider that additional inertia either has, or likely has, each of the key characteristics that support operational procurement. In Table 7.2 below, we outline our preliminary findings for each of the criteria in our first stage of the economic assessment for additional levels of inertia. This table shows the results of the Commission's assessment against the economic factors in the hurdle test. This draws from HoustonKemp's findings in Chapter 4 of its report.

The most important differences between minimum and additional inertia are that there are substitutes for additional inertia, and an undersupply does not risk the secure operation of the NEM.

We have found that additional inertia passes stage one (the hurdle test), meaning we decided to proceed to stage two, to estimate the benefits of operational procurement of additional inertia.

Table 7.2: Stage-one (the hurdle test) assessment for additional levels of inertia

What economic characteristic support spot markets?	Do additional levels of inertia have this characteristic?
The good/service can be well-defined.	**Yes:** Inertia is capable of being well defined and is sufficiently homogeneous that different inertia sources can be substituted. The potential issues relating to the stability characteristics that inertia provides as well as rate of change of frequency service are less relevant for additional inertia because stability issues are less likely to occur at higher aggregate levels of inertia — see section 8.3.1.
There are either low upfront costs or mechanisms to manage investment risks.	**Yes:** Additional inertia, being an optional service, requires significantly less guaranteed availability. There are low risks to the system if suppliers to allocate capacity to additional inertia temporarily based on the relative prices of the wholesale market, inertia procurement and fast frequency response markets. We expect any investments to supply additional inertia would either be small incremental investments (e.g. updating battery energy storage system firmware to grid forming) or driven predominantly by other revenue streams, such as the wholesale market. We note there are currently no secondary markets to help entrants manage the costs of entry, however these markets could develop in the future.
There are opportunities for efficiencies.	**Likely:** An additional inertia market would primarily aim to increase NEM efficiency by finding more dynamic ways to discover and procure the least cost mix frequency control services and suppliers, between additional inertia and FCAS markets.

What economic characteristic support spot markets?	Do additional levels of inertia have this characteristic?
There are low costs of undersupply and high costs of oversupply.	**Yes:** The costs of an undersupply of additional inertia, unlike minimum inertia, are relatively small. The costs are the inverse of the potential benefits discussed in Section 7.2; paying more for frequency control by only optimising fast frequency response and constraining supply from large generators or renewable assets. The costs of over-procuring additional inertia are similar to the costs of over-procuring minimum inertia. This is high where it requires additional investment in synchronous condensers with flywheels, extending the life of high emissions synchronous generators or reserving capacity in battery energy storage systems.
There is likely to be liquidity/competitive pressure.	**Likely:** We expect many of the sources for additional inertia would be participants in the one second FCAS markets. We consider that the one second FCAS market is reasonably competitive market and becoming more competitive as more battery energy storage systems and virtual power plants participate. We expect that similar dynamics would play out for an additional inertia market for additional inertia.

Source: AEMC, based on HoustonKemp analysis

7.2.2 We found two main sources of benefits from additional inertia when we applied the second stage of our economic assessment

Given the conclusion that additional inertia passes the hurdle test, HoustonKemp estimated the economic benefits that could arise from operational procurement of additional inertia.

There are two main sources of benefits from procuring additional inertia:

1. minimising the costs of frequency management – this is achieved by co-optimising the rate of change of frequency (through incremental inertia) with very fast frequency response (through the 1 second FCAS).
2. avoiding costs of dispatching more expensive generation outside merit order when the largest contingency is constrained down to ensure sufficient inertia.

HoustonKemp has estimated that the economic benefits of procuring additional inertia to unlock these two types of benefits could vary from $0.7 million per year to $30 million per year.[72] HoustonKemp's analysis is discussed in the sub-sections below and in Chapter 5 of its report.

Additional inertia can reduce the costs of frequency management

As we discussed in section 4.3.2, an electricity system can substitute inertia's ability to reduce the rate of change of frequency for some fast frequency response. In the NEM, this would allow AEMO to procure additional inertia when it is cheaper than one second FCAS (noting that this is not a linear 1:1 substitution).

It follows that there are benefits from allowing AEMO to procure additional inertia where this meets the system's frequency needs at a lower overall cost than just procuring one-second FCAS.

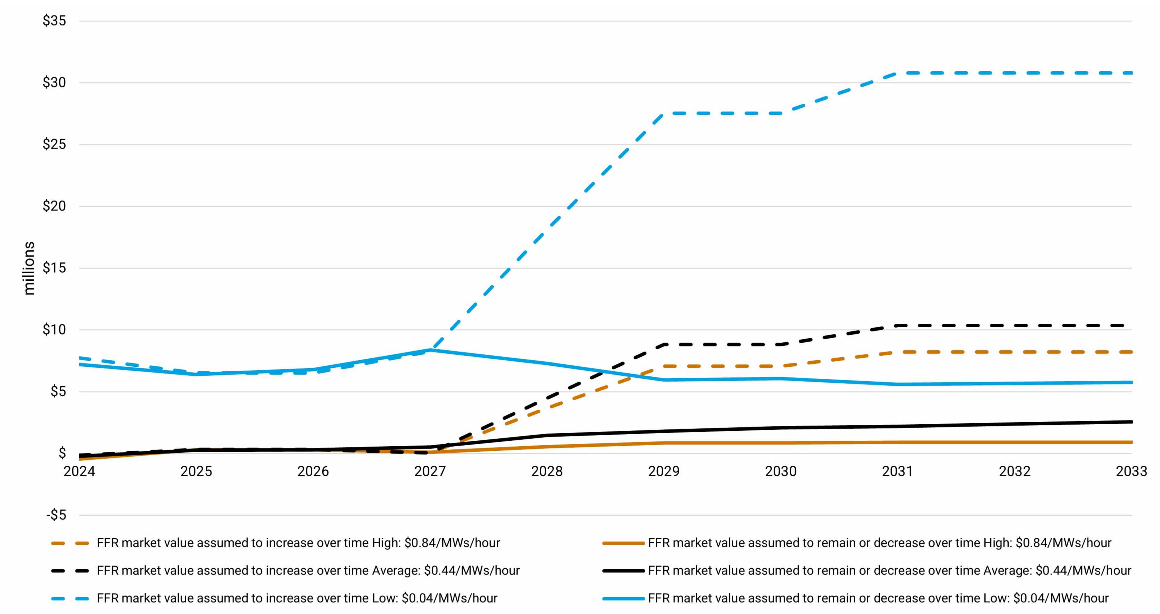
72 In 2024 dollar terms.

To estimate these benefits, HoustonKemp developed a linear optimisation model that identifies the least-cost combination of 1 second FCAS and additional inertia. HoustonKemp used supply-adjusted market prices for 1 second FCAS and its cost estimates of inertia.[73] This approach estimates the benefits of additional inertia as the avoided costs of procuring more 1 second FCAS, that is:

- the system costs of frequency control with no ability to procure additional inertia in operational timeframes, less
- the system costs of frequency control with markets for both 1 second FCAS and additional inertia.

Using this approach HoustonKemp estimated that at the upper end, these benefits range from up to $7.7 million in 2024 to between $0.9 to $30 million in 2033.[74] HoustonKemp's results (see Figure 7.1 below) show the expected benefits increasing over the 10-year time horizon.

Figure 7.1: HoustonKemp's estimates of benefits from additional inertia on frequency management



Source: HoustonKemp's Report, Figure 5.1.

Additional inertia can reduce the costs of wholesale dispatch

As we discussed in section 4.3.2, additional inertia can allow electricity systems to use larger contingencies. In the NEM we observe this in two situations:

1. at times, market dispatch may constrain the largest generating unit to operate below its potential because of insufficient inertia to support its maximum output.
2. there are binding inertia constraints in Tasmania and South Australia that limit the output of renewables.

It follows that there are benefits from allowing AEMO to procure additional inertia which would, at times, allow it to dispatch more from the largest generating units and renewables.

HoustonKemp estimated the benefits of each of the two situations separately.

73 We discuss the costs of supplying more inertia in Section 6.2.2, and HoustonKemp present its estimates in Chapter 3 of its report.

74 In 2024 dollars.

To estimate the benefits of additional inertia enabling greater output from the largest generating unit, HoustonKemp analysed historical wholesale market data to approximate how often the largest generating unit was constrained. HoustonKemp used these estimates of how often contingency constraints are in place to estimate the increase in total cost from calling on more expensive generation sources to compensate for the reduced output of the largest generating unit, less the cost of increasing inertia. We note that this analysis involves an assumption that if a generating unit was dispatched, but at less than full capacity, then this was due to an inertia constraint rather than commercial decisions about dispatch offers. Therefore, HoustonKemp generated a range of results to test the benefits if units were constrained down for inertia for different proportions of dispatch periods. This approach is discussed in more detail in section 5.1.3 of HoustonKemp's report.

HoustonKemp found benefits of between $0.7 in and $7.2 million each year.[75] As shown in Figure 5.3 of HoustonKemp's report, the size of the benefit depends largely on the proportion of dispatch periods where inertia levels are restricting output of the largest generating unit in the future.

To estimate the benefits of additional inertia alleviating the binding inertia constraints in Tasmania and South Australia, HoustonKemp analysed AEMO's Electricity Data Model for how often the inertia constraints have bound electricity dispatch in the past, and estimate the decrease in total system costs when inertia increases by 1 MWs during constrained dispatch. This approach is discussed in more detail in section 5.1.2 of HoustonKemp's report.

HoustonKemp found benefits of $2 to $20 per MWs in South Australia during constrained dispatch, and $5 to $355 per MWs in Tasmania during constrained dispatch.[76] HoustonKemp did not estimate an annual benefit, identifying high levels of uncertainty and change in these forms on constraints. HoustonKemp noted:[77]

- the constraint in South Australia is likely to disappear with completion of Project EnergyConnect Stage 2
- the constraint in Tasmania has increased over the last four years.

Question 6: Other potential benefits from operational procurement

Are there other potential benefits from operational procurement that stakeholders consider we should include in our analysis? If so, can stakeholders provide further information about how these could be modelled and / or the quantum of such benefits?

75 In 2024 dollar terms. See section 5.2.3 of HoustonKemp's report.

76 See section 5.2.2 of HoustonKemp's report.

77 We note that constraint equations are likely to change in Tasmania with the completion of Marinus Link and Project EnergyConnect.

8 There are important implementation considerations to operationally procuring inertia

Box 6: Key points in this chapter

- Chapter 7 estimated that procuring additional inertia could result in \$7.7 million to \$30 million in economic benefits per year (see HoustonKemp's report, p 36).
- This suggests that there may be benefits to consumers from procuring additional inertia — and at the top end of this range, benefits could be considerable.
- The precise extent of these benefits would depend on implementation costs and other factors that may reduce achievable benefits. We note that the benefits are estimated based on an optimisation model for the operational procurement of inertia, as explained in section 7.2.2. We also note that the implementation costs have been independently prepared by HoustonKemp, without input from AEMO. The Commission has asked AEMO to provide their views on these costs in response to this paper.
- We consider, therefore, that some form of procurement of additional inertia — whether that be a spot market, reform of existing frequency markets, or another procurement approach — may be appropriate. We do not yet have a view on what the most appropriate form of procurement could be. It could be a spot market, reform of existing frequency markets, or indeed another operational procurement approach entirely.
- Given we are seeking feedback on our direction as set out in this paper, at this stage we have focused on only two procurement models in this chapter: a standalone spot market, and reform of existing frequency markets to value inertia. Other options could include long-term procurement to meet additional inertia levels (rather than just minimums), or more sophisticated methods to optimise long-term contracts in the operational timeframes.
- There are several matters the Commission would need to further investigate and understand in order to determine which approach is in the best interests of consumers:
  - whether we can meaningfully reduce the uncertainties in the supply, demand, and benefits analysis in this paper with information that is available now. For example, we could seek further information on TNSPs' investment plans for synchronous condensers or have a better understanding on the uptake of grid forming inverters.
  - whether there are technical barriers to operational procurement of additional inertia, and whether there are policy design approaches that can overcome these barriers; or whether these would improve with increased engineering knowledge and trials over time.
  - the implementation costs of each option, including information and views from AEMO on implementation costs;
  - whether a staged approach to implementing different operational procurement approaches would be beneficial — for example, initial procurement through contracting, transitioning to operational procurement in a similar manner to the FCAS markets over time.
  - the costs and benefits of different approaches to implementation timing — in other words, option value considerations. More information is likely to become known on both inertia demand and supply in coming years, as well as the underlying physics. There are benefits

in policy certainty for enduring frameworks, but equally, there can be benefits in taking time to confirm which policy design would deliver the greatest benefits or allowing sufficient time to phase in reform.

- Feedback to this paper will inform the Commission's analysis in the next stage of this rule change, and our plan for progressing the areas identified above.

8.1 There may be benefits to consumers from procuring additional inertia

Chapter 7 estimated that procuring additional inertia could result in $7.7 million to $30 million in economic benefits per year.[78] These benefits are estimated based on HoustonKemp's optimisation model for the operational procurement of inertia, as explained in section 7.2.2, and do not take into account implementation costs or policy design. Nevertheless, we consider this shows that it is possible that consumers could receive significant benefits if additional inertia were procured.

The precise extent of these benefits would depend on two broad factors.

First, where we land in the estimated range will affect the achievable benefits. The Commission has sought feedback through chapter 6 and chapter 7 on the inputs and methodology that led to this estimate and our general conclusions on operational procurement. We are interested in any new or improved information that might be able to reduce our uncertainties in the analysis. Based on feedback to this paper, we will consider whether we can meaningfully reduce any of the uncertainties in the supply, demand, and benefits analysis in this paper with the information that is currently available. For example, we could seek further information on TNSPs' investment plans for synchronous condensers or have a better understanding on the uptake of grid forming inverters.

Second, the implementation model chosen for operational procurement, and the specific way it is designed, will affect the extent to which it can achieve the estimated benefits. This is because:

- different models have different implementation costs, and
- specific design choices within the chosen model can also affect net benefits to consumers.

These factors are explored in the following sections of this chapter and we are interested in stakeholder feedback on this analysis.

We note that the benefits estimate does not presume any particular procurement approach. In theory, these benefits could be delivered by a variety of procurement models (including, but not limited to, a spot market, a reform of existing frequency markets, further long-term contracting, or a mixture of other models as discussed above).

In this chapter, we explore operational procurement models specifically, given we are focusing on assessing these models in this paper (as discussed in chapter 1).

8.2 There is a variety of implementation models to operationally procure inertia

We have outlined two broad operational procurement models in this chapter: a standalone spot market, and reform of existing frequency markets to value inertia. Both options could operationally

78 HoustonKemp's report, p 36.

procure inertia alongside a long-term procurement framework that is currently in place (the interactions between procurement mechanisms are discussed in section 8.3).

Figure 8.1: Spectrum of procurement options for inertia

8.2.1 A new ancillary service market could be developed to procure additional inertia

Inertia could be operationally procured through a new ancillary service market — that is, a standalone inertia spot market. This may be set up in a fashion that is similar to existing FCAS markets. Under this model we would assume that:

- inertia providers would submit price-quantity bids to provide inertia (measured in MWs) for each 5-minute dispatch interval[79]
- bids would be accompanied by limits on the provisioning of inertia, similar to FCAS currently — see Figure 8.2[80]
- the dispatch engine would co-optimise additional inertia procurement with 1 second FCAS requirements
- the dispatch engine would dispatch the least-cost combination of inertia bids required to minimise the objective function of the clearing engine, even if that leads to 'partial' dispatches of inertia by some providers[81]
- all dispatched inertia providers would receive the market clearing price, which would represent the marginal price of inertia (which would likely be equivalent to the 'shadow price' of a constraint that would determine the amount of additional inertia required).
- the market could potentially also procure inertia to meet minimum inertia demand if there was a shortfall in real-time (and if this were to be the cheapest option to meet that need) — see section 8.2.3.

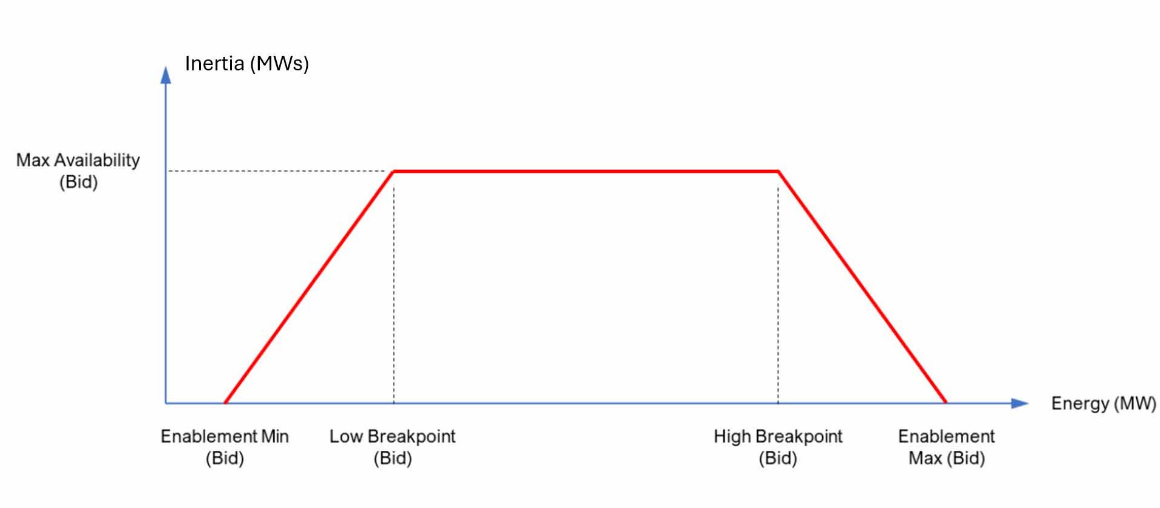
We note that such market design considerations would need to be further developed and tested if this option was to be pursued.

79 If inertia providers were able to submit 10 different price-quantity pairs, synchronous plant would only be able to make use of one. This is because they cannot vary the amount of inertia they provide when synchronised, and so only have one possible quantity of inertia they can provide. The bidding structure and rules would be a key market design choice that requires careful consideration.

80 See AEMO, FCAS model in NEMDE, p 6.

81 For example, the dispatch engine could dispatch 50 MWs of a particular synchronous provider's bid to provide all of its 200 MWs of inertia. As synchronous generators can only provide the full amount of their inertia (and not a proportion of it), it would still physically provide all of its inertia by being synchronised in the relevant dispatch interval, but may only be paid for its 'valuable' inertia. This is because NEMDE cannot accept binary variables, as it is a mixed integer linear programming — see OSM directions paper, pp. 51-52 for more information on a binary formulation vs a linear formulation.

Figure 8.2: Inertia 'trapeziums' for a hypothetical inertia ancillary service market



Source: Adapted from AEMO, FCAS Model in NEMDE, p 6.

Note: The enablement minimum and maximum could be chosen by inertia providers to represent the headroom or footroom an IBR is willing and able to trade-off to provide inertia. The enablement minimum and low breakpoint values can be negative (as batteries can still provide inertia when charging from the grid).

Note: Synchronous plant would have equivalent values for their low breakpoint and enablement minimum, as well as equivalent values for their high breakpoint and enablement maximum. This is because synchronous plant generally cannot operate a minimum loading level (and are thus not synchronised and cannot provide inertia), and cannot vary the amount of inertia they provide. Thus, the trapezium would instead resemble a 'rectangle'.

The Commission notes that the AEC's rule change request proposed a different market design, with a key feature being that all inertia providers would utilise their first price-quantity pair (for energy) as an inertia bid.[82] The Commission may consider adopting elements of the proposed model (and any other model) for a new ancillary service market if we find that those elements have a greater chance of maximising the economic benefits of procuring additional inertia, while accounting for technical and implementation challenges — see section 8.3 for more information.

8.2.2 Additional inertia could be procured by amending the existing market design of 1-second FCAS

An alternative model could be to reform existing frequency markets (specifically, the 1-second FCAS markets) to allow the procurement of additional inertia.

This would co-optimise inertia and fast frequency responses within the existing ancillary service markets to meet frequency needs at the lowest cost (see Box 7). This would set up a form of RoCoF control market, because the 1-second FCAS market procures services in order to meet the rate of change of frequency limits as specified in the Frequency Operating Standard (see section 4.1).

Similarly to the standalone spot market option described in section 8.2.1, this would:

- procure inertia services every 5 minutes
- potentially also procure inertia to meet minimum levels required, if there was a shortfall in real-time (and if this was the cheapest option to meet that need) — see section 8.2.3.

As many providers of additional inertia, particularly grid-forming inverters, are already providing 1-second FCAS, operationally procuring inertia through the FCAS markets could be a more efficient

82 AEC, rule change request, p 19.

and cost-effective way to value the different characteristics and responses of grid-forming IBR (see Box 7).

This option could be significantly cheaper than creating new market structures for additional inertia, as the existing structures and IT systems from the FCAS markets can be repurposed and used for market dispatch, and depending on implementation approach, may not require significant regulatory reform (besides amending the MASS and other related documents, such as the FCAS verification tool).

Again, we note that such market reform considerations would need to be further developed and tested if this option was to be pursued.

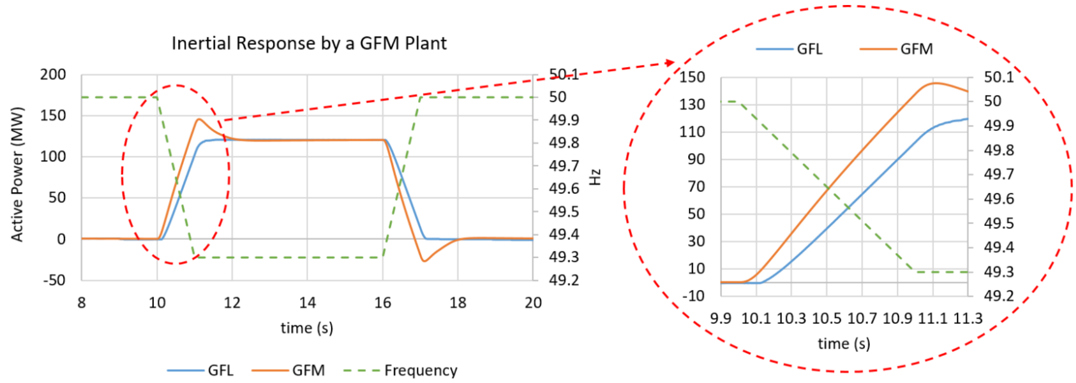
Box 7: The option of procuring inertia through amending the design of 1-second FCAS or reforming FCAS more broadly

Currently, inertial responses from synchronous generators or inverter-based plant are excluded from the 1 second FCAS markets to ensure that inertia is not conflated with the fast frequency responses of FCAS providers.[1]

Although the power system would often benefit from grid-forming responses to contingencies, the current FCAS arrangements do not differentiate between grid-following and grid-forming responses from inverter-based plant. For example, a grid-forming plant that is registered in the 1 second FCAS markets may provide an inertial response compared to a grid-following plant registered for the same capacity in the same markets. However, both plant would currently receive equivalent payments for their responses, despite AEMO likely preferring a grid-forming response in many situations (see Figure 8.3).

Following facilitative changes to the NER, AEMO could amend the market ancillary service specification (MASS) or amend (or create new) relevant FCAS constraints to better value and procure inertial or grid-forming responses through the 1 second FCAS markets. However, depending on implementation, this may require changes to NEMDE if non-linear constraint equations need to be developed to properly account for the interactions of inertial responses with fast frequency response.

Figure 8.3: The inertial response of a grid-forming plant providing inertia and FFR versus a grid-following plant providing FFR



Source: AEMO, Voluntary Specification for Grid-forming inverters, Figure 8.

Note: Both plants exhibit very similar responses, except that one plant provides synthetic inertia through their grid-forming capabilities. Currently, both plant could be accredited and registered for the 1 second FCAS markets, but their responses would be treated by the dispatch engine equivalently, despite the grid-forming response being more valuable in many situations.

Note: [1] See AEMO's Market Ancillary Services Specification, pp 10, 22, 26.

8.2.3 The potential interaction between operational procurement of inertia and AEMO enablement

In both potential models as described in section 8.2.1 and section 8.2.2, we have noted that the models to operationally procure additional inertia could also sometimes be used to procure inertia to meet minimum inertia requirements, but only if it were the cheapest option available.

As described in section 4.4.2, we consider that minimum inertia requirements should always be met through AEMO enablement of TNSP contracts, because there should always be sufficient contracts available to enable to ensure an adequate distribution and volume of inertia.

In its enablement procedures, AEMO must not enable contracts more than 12 hours ahead of the relevant dispatch interval, and should enable contracts as close as practicable to the relevant dispatch interval.[83] One potential implementation option for operationally procuring inertia is that AEMO must only enable a contract to meet gaps in minimum inertia requirements if the pre-dispatch clearing price of using the real-time procurement mechanism would be more expensive than enablement. Otherwise, if the real-time mechanism would be cheaper, AEMO may use the real-time mechanism instead of contract enablement, which would lower costs to consumers.

While the Commission still considers that the risk of under-supply against minimum inertia requirements and the economic characteristics of minimum inertia requirements are better suited to the current long-term procurement mechanism (see section 7.1), we also consider that:

- there may be operational benefits to allowing AEMO to use another tool to meet minimum inertia requirements that may sometimes be cheaper than enabling TNSP contracts
- there may be some economic benefits to operationally procuring ***gaps*** in minimum inertia requirements (as opposed to procuring the entire minimum level of inertia) to reduce overall costs to consumers.

As is discussed below in section 8.3, there are also various choices and considerations that would need to be made to ensure that there no adverse consequences of allowing operational procurement to meet gaps in minimum inertia requirements — for example, the eligibility of generators and integrated resource providers who already hold contracts with TNSPs for their inertia.

8.3 We would need to consider how market design choices and practical limitations could affect the potential economic benefits of procuring additional inertia

8.3.1 We would need further technical advice to determine the feasibility of operational procurement of additional inertia

As outlined in chapter 1, this directions paper outlines our economic analysis of whether there may be benefits from operational procurement of inertia in the NEM. We have identified potential benefits — however, there remain technical questions about the feasibility of operational procurement of inertia. Technical challenges that may arise could be broadly split up into two categories:

1. Operational challenges of formulating linear constraints relating to the co-optimisation of inertia with other system requirements and other market design choices that may create infeasible solutions within NEMDE, due to linear programming limitations
2. Adverse power system effects that may arise due to a lack of knowledge about the interactions between inertia providers and other plant and equipment under varying network

83 NER, clause 4.4A.4(b)-(c).

conditions, especially under lower aggregate levels of inertia or constantly shifting distributions of inertia.

AEMO discusses the need for a distribution of inertia across the NEM in its inertia requirements methodology, noting that limits on active power flow through the network, and the potential for islanding, mean that a certain level of inertia is required in each NEM region.[84] However, this may be less of a concern for the operational procurement of additional inertia, as there would already be adequate inertia located in each region due to the system-wide inertia levels being allocated across mainland NEM regions by meeting the minimum inertia requirements.

We have concluded that a long-term procurement mechanism is currently most appropriate to deliver minimum levels of inertia in the NEM. To assess the future feasibility of the operational procurement options we have identified, the Commission intends to investigate any technical and operational challenges and questions arising in the next phase of this rule change request.

Key areas for further exploration include the:

- locational effects of and requirements for inertia, especially due to rapidly shifting distributions of inertia or low aggregate levels of synchronous inertia
- technical and regulatory integration of grid-forming inverter responses, to maximise system benefits
- practical challenges associated with dynamically co-optimising inertia alongside other system services, which may be due to the characteristics of NEMDE. This includes assessing any limitations or mitigations that may be necessary for the market design and implementation.

8.3.2 Market design choices affect participant incentives and efficiency — and therefore influence consumer benefits

Design of an operational procurement approach for inertia would be complex. For both models outlined in section 8.2, and any other model that may be considered, key policy design questions would include those listed below in Table 8.1.

Table 8.1: Market design questions that must be considered for operationally procuring inertia

Market design question	Discussion
Eligibility of inertia providers	• Consideration must be given to whether market participants who are a party to TNSP system security contracts would be eligible for operational procurement of inertia • To mitigate the risk of unintended market consequences related to some synchronous assets, the eligibility for participating in a spot market could mandate that all inertia providers must be able to provide inertia at 0 MW (that is, separately from energy). This may reduce distortions in the energy market.
Bid structure	Choices include: • allowing ten price-quantity pairs, similar to existing FCAS markets • only allowing one price-quantity pair, but with similar limits on enablement (see Figure 8.2)

84 AEMO, Inertia Requirements Methodology, pp 8-9.

<table>
<tr><th>Market design question</th><th>Discussion</th></tr>
<tr><td></td><td>reusing the first energy bid band as an inertia bid, as per the rule change request (but consideration would have to be made whether these providers should have another bid band for energy, as they may have one less band to express their bidding preferences)
any other bidding structure proposed by stakeholders.</td></tr>
<tr><td>Cost allocation</td><td>A typical causer-pays approach may erode revenues earned in the spot market, as some providers of inertia are often large contingencies themselves or cannot withstand a high RoCoF.
Under a RoCoF withstand causer-pays approach, one option could be to assume market participants are able to withstand a maximum of 1 Hz/s (or 3 Hz/s in Tasmania) as per the FOS, unless they can prove that they can withstand higher RoCoFs.
Runway pricing could also be considered to allocate FCAS and inertia costs to market participants — see the pending rule change request Allocating contingency FCAS costs.
Costs may otherwise be smeared proportionally across all market participants based on their generation or load size.</td></tr>
<tr><td>Marginal pricing and partial dispatch</td><td>As NEMDE must calculate marginal prices, partial dispatch of inertia providers could occur.
Rules around how participants must treat partial dispatches need to be considered:
A partial dispatch of a synchronous plant would mean that it must synchronise and provide all of its inertia (but only be paid for its valuable portion)
A partial dispatch of an asynchronous plant may mean it could lower its inertia constant to provide a slightly weaker inertial response (compared to its maximum registered capability), but could lead to instabilities if inverter settings are improperly tuned and controlled.</td></tr>
<tr><td>Linear formulation of inertia constraints</td><td>The relationship between inertia and fast frequency response is often non-linear. Linearising this relationship may not accurately represent the physical nature of the power system, and could create undesirable outcomes if improperly formulated.
It may be simpler to consider additional inertia and 1-second FCAS requirements in the same constraint equation (in which case, operational procurement of inertia could be similar to the option considered in section 8.2.2). Requirements for minimum inertia could be largely handled by AEMO's enablement tool for minimum system security requirements, which does not need to be integrated into NEMDE.</td></tr>
<tr><td>How to treat inertia from already-synchronised generation</td><td>Currently, 1-second FCAS requirements are set with reference to how much inertia is present in the power system from synchronised generation. This synchronised generation is receiving revenue from the energy market, but is not receiving any revenue from the 1-second FCAS market.</td></tr>
</table>

Market design question	Discussion
	• Any future operational procurement mechanism must consider how to treat market participants who are cleared in the energy market (or enabled by AEMO) and who are not participating (or eligible to participate) in an additional inertia market, and whether they should be paid the marginal clearing price of additional inertia. • The Commission considers that any additional payment to already-synchronised generators must lead to gains in economic efficiency in order to contribute to the NEO. However, it is not clear how these payments would result in any behavioural changes, particularly because synchronous generators cannot separate their inertia provision from their energy provision. • There would be no corresponding reduction in their energy bids due to the inseparable nature of energy and inertia. These payments could then result in a wealth transfer from consumers to operators, without any clear improvement in economic efficiency.

Potential increases in emissions caused by out-of-merit order dispatch	• If a thermal plant is cleared for inertia on the basis of its inertia bid, but not cleared in the energy market due to it being out of the merit order, then it would be dispatched out-of-merit for energy as it cannot provide its inertia independently of energy. As the dispatch engine does not consider the value of emissions reduction, it may lead to a net increase in costs over time when valuing emissions increases due to out-of-merit order dispatch.
	• Potential mitigations could include:
	  ◦ the dispatch engine cannot consider any synchronous plant for inertia, if it would be desynchronised in the relevant dispatch interval (that is, not in the merit order for the energy market as well)
	  ◦ synchronous plant must only bid zero, making them price-takers only in the inertia market
	  ◦ mandating that a portion of the additional inertia requirement is met by zero-emissions sources.

Allowing inverter-based plant to provide varying amounts of synthetic inertia	• As described in section 4.2.2, inverter-based plant are able to vary their inertial responses in many ways, which can provide frequency control, voltage control and other power system benefits dynamically. • However, the current performance standard framework would disallow inverter-based plant from dynamically varying their responses to frequency and voltage disturbances, as it currently requires a NER 5.3.9 alteration. • To maximise potential power system benefit in the future, consideration should be made on whether to reform relevant Chapter 5 clauses, as well as to the MASS, to allow more dynamic responses from future plant. • Limiting asynchronous plant to one standardised inertial response may be most practicable in the short-term, but is not particularly future-focused and may limit potential long-term benefits.

Market design question	Discussion
Mitigate market power issues	• Market participants who hold some degree of market power may be economically incentivised to engage in non-competitive bidding behaviours in order to increase the price of procuring additional inertia, FCAS, energy, or AEMO enablement of contracts. • The Commission welcomes stakeholder feedback on suggestions on how to best mitigate the effects of any market power that may be exercised through any new operational procurement mechanism.
Design of reporting, compliance and monitoring arrangements	• Market transparency and information are important for all stakeholders to ensure that efficient investment decisions and choices can be made in the long-term interests of consumers. • The Commission will consider the most effective way to design these arrangements if a mechanism for operationally procuring inertia is likely to provide significant economic benefits to consumers.

8.3.3 Implementation costs are likely to differ for each implementation model

The Commission has not sought detailed cost estimates for implementation for any specific operational procurement model. We intend to further investigate the magnitude of implementation costs of different broad models, and then seek detailed estimates for any preferred specific model, as part of the next stage of this project. In particular, we have asked AEMO to provide their views on cost estimates in response to this paper.

In its report, HoustonKemp has independently estimated that a spot market would have a 10-year net present value implementation cost of $20 million to $50 million.[85] This is made up of:

- $5 million to $10 million in costs for establishing the market. This is based on adjusting AEMO's costs for the 1-second FCAS market for the more complicated requirements of an inertia market.
- $1 million to $2 million in annual costs for AEMO.
- $200,000 to $400,000 in annual costs for each participant in the inertia market.

These costs may turn out to be different once we understand from AEMO in further detail their views about implementation costs. We anticipate that the costs may be higher than what HoustonKemp estimated due to the intricacies of NEMDE and associated IT systems.

There are likely to be some extra or different implementation considerations if an operational market that included inertia were set up.

For example, a standalone inertia spot market could require changes to NEMDE, due to the non-linear relationships between inertia and other power system security requirements, particuarly fast frequency response. There may also need to be improvements to how inertia levels are monitored in real-time (noting that regional synchronous inertia levels are currently monitored through non-binding monitoring constraints).[86] This may significantly increase the costs of this option above the $20 to $50 million level.

85 Houston Kemp report, p 43.

86 The constraints DSNAP_INFO_NSW_INER, DSNAP_INFO_QLD_INER, DSNAP_INFO_VIC_INER, DSNAP_INFO_SA_INER, DSNAP_INFO_TAS_INER and DSNAP_INFO_TNTH_INER all monitor regional and sub-regional levels of synchronous inertia.

We are also interested in market participant views on the estimated costs.

As grid-forming technology is likely to evolve and improve in the future, ensuring that the MASS and existing FCAS arrangements can efficiently incorporate and value beneficial grid-forming responses that can contribute to frequency management would be ideal (see Box 7).

Incorporating inertial or grid-forming responses into the existing 1 second FCAS markets could deliver the economic benefits of procuring additional inertia at a lower cost than creating a new inertia spot market. However, we do not have a robust estimate of the implementation costs of this option. HoustonKemp's estimate provides a starting point, but the Commission would need investigate all potential policy and market designs in order to determine the relevance of this estimate.

8.4 We would also need to consider implementation timing and staging

8.4.1 The benefits and most suitable design details of implementing operational procurement are likely to become clearer over the next few years

We concluded in chapter 7 that there are potential benefits from procuring additional inertia, and that operational procurement (such as a spot market) seems suited to procuring this level of inertia.

Figure 7.1 shows that the benefits in early years are relatively lower than those in the later years — which make up a much greater proportion of the benefits. Additionally, the amount of these benefits are uncertain, depending on future prices in FCAS markets, how inertia constraints evolve with the commissioning of Project Energy Connect Stage 2 and Marinus Link, and how AEMO treats contingency size with respect to renewable energy zones and offshore wind farms. Therefore, we may be able to capture most of the estimated benefits even if we do not proceed to immediate implementation of operational procurement.

We face a number of uncertainties in future inertia demand and supply, as explored in chapter 6. We consider that the numbers of synchronous condensers entering the NEM over the coming years, as well as the uptake of grid-forming inverters (and the knowledge about how these can substitute for synthetic inertia) is a key uncertainty.

Synchronous condensers would provide inertia continuously, and in significant numbers could provide significantly more than the minimum inertia requirements of the NEM over the next one to two decades. A more precise understanding of how many synchronous condensers will be built in the next few years would help inform the level of potential benefits we may see from the procurement of additional inertia — and therefore, whether there is benefit in investing in the implementation costs necessary to set up operational procurement.

Additionally, AEMO's new transitional services framework can trial technologies that would assist in the creation of a procurement mechanism for additional inertia. Specifically, type 2 transitional service contracts, which have the objective of trialling new technologies for the management of power system security in low- or zero- emissions power system, can be leveraged to trial synthetic inertia providers to deliver:

- the benefits of additional inertia to lower overall dispatch costs
- the benefits from dynamically shifting inverter responses to better support the power system (for example, dynamic inertia constants, damping constants, reactive power capability, etc.)

Premature or inappropriate development of a market for additional inertia may not account for the technological benefits that can be leveraged from such trials and transitional service contracts, and from AEMO's transition plan more broadly.[87]

8.4.2 A staged implementation may help manage regulatory change

The Commission also recognises that security frameworks have undergone significant change in recent years, with changes to both the system strength and inertia frameworks being implemented currently. These changes were critical for ensuring that enough security services are available to keep the NEM secure.

When considering amendments to inertia procurement frameworks, we would need to consider how to minimise regulatory uncertainty and change. Given a new inertia operational procurement mechanism would be a significant and potentially complex market change, there would likely need to be a substantial lead time and transitional period before it commenced operation.

One way of smoothing a transition could be a staged approach, where an initial simpler procurement approach is used before transitioning to a more complex framework. For example, additional inertia could be initially procured through contracts, with a clear plan and timeline to transition over time to a full operational procurement model. This would be similar to the evolution of frequency markets in the NEM, which initially used a contracted procurement approach before transitioning to full ancillary services markets.[88]

Question 7: Implementation considerations

Do stakeholders have suggestions on implementation considerations that should be taken into account? For example, how we can mitigate regulatory uncertainty?

87 AEMO, 2024 Transition Plan for System Security.

88 ACCC, Application for authorisation, Amendments to the National Electricity Code (October 1998), p 27.

Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
FCAS	Frequency control ancillary service
FFR	Fast frequency response
FOS	Frequency Operating Standard
GFM	Grid-forming
GW	Gigawatt
IBR	Inverter-based resource
ISF	National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024
MASS	Market Ancillary Service Specification
MW	Megawatt
MWs	Megawatt-seconds
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSP	Network service provider
NT Act	*National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
Proponent	The individual / organisation who submitted the rule change request to the Commission
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rate of change of frequency
Syncon	Synchronous condenser
TNSP	Transmission network service providers
WEM	Wholsale Electricity Market (operated in Western Australia)