RULE

Australian Energy Market Commission

## DIRECTIONS PAPER

# NATIONAL ELECTRICITY AMENDMENT (IMPROVING SECURITY FRAMEWORKS FOR THE ENERGY TRANSITION) RULE 2023*

**PROPONENTS**

Hydro Tasmania
Delta Electricity

24 AUGUST 2023

**Formerly the Operational security mechanism*

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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

1 The Australian Energy Market Commission (AEMC or Commission) is proposing a revised approach to the 'operational security mechanism' (OSM) rule change, after carefully considering stakeholder feedback on the OSM draft determination, which was released in September 2022.

2 This directions paper and the proposed rule drafting provide details on a simpler approach compared to that articulated in the draft determination. The proposals outlined involve building on existing tools in the power system to allow direct procurement of system security more quickly and easily. This approach would address system security issues through the transition, reduce the regular and inefficient use of directions, and provide better incentives for participants to invest in providing system security in the longer-term.

3 The Commission has also revised the name of the rule change to: 'Improving security frameworks for the energy transition'. This is to better encapsulate the revised approach that now focuses on enhancing existing frameworks to provide system security needs to support the power system through the transition, rather than creating a mechanism (the OSM) to procure and operationalise security services.

4 We are seeking feedback on the proposals in this directions paper and the proposed draft rule by **5pm 28 September 2023**, ahead of publishing a final determination later this year. There are a variety of ways to provide feedback from participating in our public forum and bilateral meetings to providing formal submissions.

## There continues to be an important problem to address

5 The National Electricity Market (NEM) is going through a significant transformation, with the generation mix changing due to decarbonisation, changing technology costs, and consumer preferences. The NEM's regulatory and market frameworks were originally designed around a power system made of primarily synchronous generation which inherently provide an abundance of security services as a by-product of energy generation.

6 However, fewer of these services are being provided as the generation mix changes to non-synchronous plant, which connects to the power system through power electronics, and does not automatically provide all types of security services as a by-product of generation.

7 Over time, the Australian Energy Market Operator (AEMO) will increase its understanding of the security capabilities of the new generation mix, allowing it to implement new ways of ensuring system security. This is crucial for operating the grid at 100% renewables, as the current methods of ensuring system security are reliant on synchronous generators. To achieve this, AEMO will most likely need to analyse and progressively test new operating states of the power system. Throughout this transitional period, security services will continue to be scarce at times.

8 It is important to address this scarcity by providing the right incentives for participants to provide security services through the transition. In planning timeframes, there are existing frameworks that provide some incentives by enabling procurement of security services —

specifically the inertia, system strength and network support and control ancillary services (NSCAS) frameworks. In operational timeframes, however, given the current status of engineering knowledge, AEMO cannot specify individual security services or operate the system by managing security services individually. This results in limitations as to what enhancements to the current frameworks can be made. For example, individual markets to procure a specific system service cannot currently be introduced given that the services cannot be specified in operational timeframes.

9 Due to these current limitations, AEMO is managing the system through asset configurations. These are specific configurations of the power system that represent a secure technical operating envelope within which a secure power system can be modelled and operated with a high level of confidence.

10 AEMO is currently using directions to ensure that the system is secure on the basis of these configurations. Reliance on directions, which are meant to be used as a last resort mechanism, increases security risks on the power system because of inadequate transparency, increased administrative burden, not providing certainty to participants, and not supporting trials of new technologies to support power system security. The Commission and stakeholders agree the current approach will not meet the needs of a transforming power system.

11 Instead, we need to ensure the future requirements of the power system are met by providing incentives for new entrants and existing participants to make investment decisions that would see system security provided in the longer-term. The Commission is committed to working towards a net-zero grid and economy, and to achieve this we need solutions that support the power system through the transition.

## The Commission has revised the direction of the OSM rule change based on stakeholder feedback

12 Following stakeholder feedback from the 2021 directions paper, the AEMC proposed a draft rule to introduce a mechanism called the OSM. While the detailed design is outlined in the OSM draft determination, key design features of the OSM included:

- AEMO would be responsible for defining the system security needs and accrediting market participants to supply system services
- accredited market participants would bid to provide system services into the OSM close to real-time
- OSM schedules would be published to enable participants to position their units accordingly
- providers of services through contracted arrangements with networks, such as system strength or inertia, could be incorporated into the OSM.

13 While submissions to the draft determination showed stakeholders broadly supported taking action to ensure a more efficient and transparent approach, other than directions, to manage system security, there were a number of fundamental questions and concerns raised. These concerns included:

- whether operational procurement of services that are difficult to define would provide clear and predictable long-term investment signals
- whether the proposed 'pay as bid' arrangements would provide incentives in an economically efficient way
- whether the proposed operational procurement and scheduling arrangements would significantly interact with the energy spot market
- market power concerns.

14 After carefully considering the submissions to the draft determination, the Commission determined the OSM would be too costly and complex to develop and implement and would be unlikely to deliver the intended outcomes.

15 Given that it is not currently possible to specify individual services in operational timeframes, it is not possible to move from an asset-based framework to a service-based framework at this time. It is important that engineering knowledge and understanding of future technologies be developed further before this is possible.

16 The Commission decided that instead, a simpler solution was required that can be implemented within a shorter timeframe and can meet the needs of the system during the transition. The Commission considers this approach to have greater benefits than implementing the proposed operational procurement and scheduling mechanism. It is necessary to establish a greater understanding of the engineering and technical capabilities of the system before introducing complex market changes. In the meantime we already have comprehensive security frameworks that procure security services such as system strength, inertia and NSCAS, which can be built on.

## The Improving security frameworks rule change focuses on improving long-term planning frameworks to achieve a simpler and faster solution

17 The revised rule change focuses on:

- aligning the existing inertia and system strength frameworks
- removing the exclusion to procuring inertia network services and system strength in the NSCAS framework
- creating a new transitional non-market ancillary services (NMAS) framework for AEMO to procure security services necessary for the energy transition.
- empowering AEMO to enable ( or 'schedule') security services with a whole-of-NEM perspective
- improving directions transparency and compensation.

18 Considered together, these solutions focus on addressing the needs of the power system today and supporting power system security through the transition to 100% instantaneous inverter-based resources (IBR). The solutions are set up to be able to adapt as the needs of the power system, and our understanding of it, develop in the longer-term.

## The Commission is proposing improvements to the existing inertia and system strength system security frameworks

19 The Commission is proposing three main changes to the existing inertia framework: introducing a NEM-wide inertia floor, aligning procurement timeframes with the system strength framework, and removing restrictions on the procurement of synthetic inertia. Aligning the inertia and system strength frameworks would allow transmission network service providers (TNSPs) to more efficiently coordinate investment opportunities, while enabling the procurement of synthetic inertia would promote system security and economic efficiency.

20 The Commission is also proposing to remove the exclusion on inertia network services and system strength under the NSCAS framework to ensure there is a backstop procurement arrangement in place to procure these services where a shortfall emerges in the near term before the primary frameworks can address it.

21 These changes aim to address issues and promote opportunities in the current frameworks to create proactive, forward-looking, and enduring frameworks to help ensure system security and reduce the use of directions.

22 The proposed changes to align the inertia and system strength procurement timeframes would commence on 1 December 2024, meaning that binding procurement of the mainland inertia floor would commence from 1 December 2027.

## A new NMAS framework would help keep the system secure through the transition

23 The Commission proposes to introduce a new NMAS framework for 'transitional services'. This would allow AEMO to procure to meet system security needs that are related to the system transition and not captured in existing planning frameworks. While the Commission still recognises there are efficiency benefits in individually valuing and procuring security services, given the current reality of system needs, this is not yet feasible in practice.

24 The transitional services framework would therefore allow AEMO to procure specific security services for known configurations that are needed to maintain power system security, rather than relying on directions. This framework would be transitional because it would enable AEMO to procure these configurations until engineering capabilities develop to understand the security capabilities of the new generation mix. The transitional services framework could be used by AEMO to trial and conduct experimentation on how these newer technologies could contribute to system security.

25 This framework would only be used to procure for system security needs that are not captured in existing frameworks. AEMO would be required to outline its reasons for procuring these needs in the framework and would be required to outline the ongoing cost and services of the new framework each year. The new framework would sunset after 10 years, with a review of its effectiveness occurring after seven years.

26 The Commission considers that AEMO would be able to procure for security services under

the new NMAS framework as soon as AEMO has published a procurement guideline.

## AEMO would be empowered to schedule long-term planning contracts for security

27 To capture the full benefits of the proposed changes to long-term planning frameworks, the Commission considers that AEMO should enable (or 'schedule') planning timeframe contracts for system security. AEMO would only enable contracts where there is a gap between the security outcomes of projected dispatch and the required levels for each security need. AEMO would not enable contracts to meet the entire volume of system security needs.

28 AEMO would publish an enablement guideline that would outline how AEMO forecasts system security requirements, how it makes and communicates enablement decisions, and the timing of its enablement decisions.

29 An arrangement for allowing AEMO to operationally enable long-term contracts for system strength, inertia, NSCAS and the new NMAS would promote efficiencies. This is because AEMO would have the ability to schedule contracts with a whole-of-NEM perspective.

30 The Commission considers enablement decisions should support the policy intent of the long-term frameworks for managing system security. This means contracts would be enabled to meet minimum and transitional security requirements, as well as host projected IBR online, as per the respective security requirements of each framework.

31 These arrangements would commence on 2 December 2025, which is when system strength obligations under the new system strength framework commence.

## The Commission is proposing improvements to compensation and transparency arrangements for directions

32 The proposed reforms to inertia, system strength and NSCAS, and the new NMAS arrangements, should all help to reduce the number of security directions issued by AEMO. Directions should remain a last-resort mechanism, however as the system transitions, we recognise directions may be used from time to time. The Commission is looking at opportunities to improve transparency and compensation arrangements of directions.

33 Stakeholders and the Commission believe there are opportunities to improve transparency by including more valuable information in real-time market notices, as well as improving post-fact reporting.

34 At the time of issuing a direction, AEMO's market notices would be required to identify all directed participants and provide detail about the nature of the direction and the circumstances that have caused the need for a direction.

35 AEMO would be required to prepare a detailed quarterly report that includes trends observed in directions in each quarter, AEMO's view on whether directions may be required in future reporting periods, and a breakdown of compensation amounts payable to each directed or affected participant. This would replace the requirement for AEMO to prepare a report for every direction event.

36 The proposed changes focus on improving transparency by ensuring participants receive valuable information in a timely manner, while also minimising the administrative burden on AEMO.

37 Directions compensation is currently based on the 90$^{th}$ percentile price for energy or frequency control ancillary services (FCAS) over the preceding 12 months from when the direction was issued. The Commission considers this basis runs a high risk of over or under-compensating participants.

38 The Commission is proposing to amend the basis of directions compensation to a benchmark-based compensation framework, similar to the framework used during market suspension periods. This would ensure directed participants would be entitled to compensation based on predetermined values that reflect a benchmark short-run marginal cost (SRMC) for the relevant technology type, as determined through ISP data inputs. This will reduce the risk of under or over-compensation and better balance the needs of generators and consumers.

39 The proposed changes would commence on 1 July 2024, to align with the start of the 2024-25 financial year.

## Engaging with our process

40 This directions paper has been prepared to facilitate public consultation on the rule change requests and to seek stakeholder submissions on the issues presented. The Commission invites stakeholders to make submissions for a period of five weeks, with submissions due by 5pm, 28 September 2023.

41 Submissions can be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function.

42 The Commission will hold a **public forum** on this directions paper as part of our consultation and engagement with stakeholders on these rule changes. This forum will be held on 14 September 2023. Interested stakeholders are invited to register via the Commission's website.

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# 1 THE COMMISSION IS PROPOSING IMPROVEMENTS TO SYSTEM SECURITY PROVISION FRAMEWORKS TO SUPPORT THE SYSTEM TRANSITION

### BOX 1: KEY POINTS IN THIS CHAPTER

- This directions paper seeks stakeholder feedback on the Improving security frameworks for the energy transition (Improving security frameworks) rule change, which considers stakeholder feedback to the draft determination and the two rule change requests from Hydro Tasmania and Delta Electricity.
- After carefully considering the submissions to the draft determination the Commission considered the Operational security mechanism (OSM) would be too costly and complex to implement. The Commission decided a simpler and more timely solution was required.
- The revised approach is now focusing on long-term procurement through the security planning frameworks to address security needs in the transition, rather than through operational procurement.
- The Commission views the name 'Operational Security Mechanism' does not clearly illustrate the revised approach, which now focuses on enhancing existing long-term frameworks to provide system security needs to support the power system through the transition. To clearly encapsulate the revised approach, the Commission is calling this rule change 'Improving security frameworks for the energy transition'.
- The Commission is committed to working towards a net-zero grid and a net-zero economy. To achieve this, we need solutions that focus on supporting the power system through the transition.
- The revised approach outlined in this paper ensures the opportunities identified in the OSM rule change process to date continue to be progressed while addressing several issues identified in the draft determination, including the importance of providing long-term investment signals, avoiding complex and irrevocable interactions with the energy spot market, and market power concerns.
- The assessment criteria considers the National Electricity Objective (NEO), the new emissions reduction objective, and the system services objective.
- Written submissions responding to this directions paper must be lodged with Commission by **5pm, 28 September 2023**.

The Australian Energy Market Commission (AEMC or Commission) is proposing a revised approach to the OSM rule change, after carefully considering stakeholder feedback to the OSM draft determination, including changing the name to Improving security frameworks for the energy transition (Improving security frameworks).

The Commission has decided to change its approach to focus on simpler and more timely solutions for system security than the operational procurement and scheduling mechanism in the draft determination, which would have been costly and complex to implement.

This directions paper and the proposed draft rule provide detail on our revised approach. This approach involves building on existing tools in the power system to allow direct procurement of system security more quickly and easily. The Commission considers this approach, although simpler than the draft determination's approach, would address the system security issues raised in this rule change. This would reduce the regular and inefficient use of interventions and provide better incentives for participants to invest in providing system security in the longer term.

The Commission is seeking stakeholder feedback on this paper, ahead of publishing a final determination in December 2023.

This section provides context on, and gives a brief overview of, the revised approach including:

- Section 1.1 — This directions paper seeks stakeholder feedback on the Improving security frameworks rule change, ahead of a final determination
- Section 1.2 — The rule change has been renamed to reflect the revised approach
- Section 1.3— There continues to be an important problem to address to ensure future system security requirements of the power system are met
- Section 1.4— The revised approach focuses on improving long-term planning frameworks to achieve a simpler and faster solution
- Section 1.5 — The assessment considers the NEO and the system services objective
- Section 1.6 — How to make a submission

## 1.1 This directions paper seeks stakeholder feedback on the Improving security frameworks rule change, ahead of a final determination

The Commission consolidated two rule change requests, one from Hydro Tasmania[1] and the other from Delta Electricity[2] to be considered in this project. The rule change requests proposed operational procurement mechanisms to better value, procure and schedule essential system services (ESS) to help keep the system secure. These are detailed in appendix A, with the two different approaches to scheduling and provision of ESS:

- Hydro Tasmania proposed an approach to address the shortage of "inertia and related services" in the national electricity market (NEM) by explicitly valuing the provision of services in real-time, in much the same way that energy is valued.[3] The pre-dispatch and dispatch engines, which currently provide forecast and actual dispatch targets and prices

1 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019.

2 Delta Electricity, Capacity commitment mechanism for operational reserve and other system services, Rule change request, 4 June 2020.

3 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, p.2.

for energy and market ancillary services, would be altered so that they also determine forecast and actual dispatch targets and prices for other essential system services.[4]

- Delta Electricity proposed to introduce an ex-ante, day-ahead "capacity commitment mechanism" and payment system so that generators or demand response providers remain available to offer operational reserve and any other system security or reliability services that the Australian Energy Market Operator (AEMO) may require to meet its security and reliability objectives.[5] AEMO would determine system service requirements and, through a market operating ahead of real-time, procure these services from market participants.[6]

In September 2022, in response to the rule change requests, the Commission released a draft determination to establish an OSM in the NEM.

The OSM was designed to co-optimise the procurement of security services, energy, and frequency control ancillary services (FCAS). It would have operated parallel to the spot market. Key design features of the OSM included:

- AEMO would be responsible for defining the system security needs and accrediting market participants to supply system services
- accredited market participants would bid to provide system services into the OSM close to real-time
- OSM schedules would be published to enable participants to position their units accordingly
- providers of services through contracted arrangements with networks, such as system strength or inertia, could be incorporated into the OSM.

Submissions to the draft determination showed stakeholders broadly supported taking action to ensure a more efficient and transparent approach, other than directions, to manage system security. However, stakeholders raised a number of fundamental questions and material concerns about the design and objective of the OSM and the details of the draft rule.

These concerns included:

- whether operational procurement of a service that is difficult to define would be likely to provide clear and predictable long-term investment signals for participants
- whether the proposed arrangements with a 'pay as bid' structure (where parties are paid the price they bid at) would provide sufficient incentives to deliver system security in an economically efficient way
- the proposed operational procurement and scheduling arrangements would significantly interact with the energy spot market, altering energy market signals and decreasing its efficiency through the introduction of 'aheadness'

4 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, p.2.

5 Delta Electricity, Capacity commitment mechanism for operational reserve and other system services, Rule change request, 4 June 2020.

6 Delta Electricity, Capacity commitment mechanism for operational reserve and other system services, Rule change request, 4 June 2020, p. 24.

- market power could be exercised to increase prices due to a limited number of system configurations or participants in certain regions.

After carefully considering these submissions to the draft determination, the Commission considered the OSM would be too costly and complex to implement. The Commission decided a simpler and more timely solution was required.

The Commission considers that a focus on simplicity and flexibility, rather than complex mechanisms for operational procurement, could result in greater benefits and less costs for consumers. There are two main reasons for this:

- There are benefits to waiting for a greater understanding of the engineering and technical capabilities of the system before introducing complex market changes. Our understanding is still developing about system security needs through the transition (including our ability to define services rather than relying on asset configurations), and how new technologies will contribute to security. AEMO advises that currently individual services cannot be specified in operational timeframes, limiting what available options we have. Markets require services to be individually specified, and so, engineering knowledge needs to be developed further to be able to specify these security services. The Commission considers progress is likely in coming years on these matters.
- We already have security frameworks that are comprehensive and allow for procurement of services – system strength, inertia and network support and control ancillary services (NSCAS). A simple yet effective approach is to ensure these frameworks are set up to enable procurement of security services to support the transition, and that they can be scheduled in real-time. Building and streamlining existing frameworks so they work better through the transition is likely to put in place arrangements quicker and allows change to be more impactful.

## 1.2 The rule change has been renamed to reflect the revised approach

This directions paper sets out a revised approach to the  OSM rule change, which still responds to the core issues raised by stakeholders and the rule change requests, but also addresses the material concerns raised by stakeholders about the OSM model in the draft determination. The revised approach now focuses on enhancing existing frameworks to provide system security needs to support the power system through the transition. As such, the revised approach no longer seeks to implement a mechanism (the OSM) to procure and operationalise security services.

The Commission has therefore revised the name of this rule change to the 'Improving security frameworks for the energy transition' rule change to better encapsulate the revised approach.

## 1.3 There continues to be an important problem to address to ensure future system security requirements of the power system are met

The NEM is going through a significant transformation with the generation mix changing, driven by decarbonisation, changing technology costs, and consumer preferences. This significant transformation is testing the limits of current system security and operational experience.

The NEM's regulatory and market frameworks were originally designed for a power system made up primarily of synchronous generation (coal-fired, gas-fired, and hydro-powered generators) that are electromagnetically coupled to the power system. These generators inherently provide an abundance of ESS as a by-product of energy generation.

In contrast, non-synchronous plant, (such as solar, wind, and batteries) connect to the power system through power electronics. While they can be configured to provide some security services, they do not do this automatically as a by-product of generation. This means fewer of these services are being provided as the generation mix shifts, with few, if any, investment signals to encourage these services.

Over time, AEMO will increase its understanding of the security capabilities of the new generation mix, allowing it to implement new ways of ensuring system security. This is crucial for operating the grid at 100% renewables, as the current methods of ensuring system security are reliant on synchronous generators. To achieve this, AEMO will most likely need to analyse and progressively test new operating states of the power system. Throughout this transitional period, security services will continue to be scarce at times.

It is important to address this scarcity by providing the right incentives for participants to provide security services through the transition. In planning timeframes, there are existing frameworks that provide some incentives by enabling procurement of security services — specifically, inertia, system strength and NSCAS. In operational timeframes, however, given the current status of engineering knowledge, AEMO cannot specify individual security services or operate the system by managing security services individually. AEMO manages the system through asset configurations - specific configurations of the power system that represent a secure technical operating envelope. This results in limitations as to what enhancements to the current frameworks can be made. For example, individual markets to procure a specific system service cannot currently be introduced given that the services cannot be specified in operational timeframes.

In this context, AEMO is increasingly directing generators to be online, when they would otherwise have not been, to provide these services. Reliance on directions, which are meant to be used as a last resort mechanism, increases security risks on the power system because of inadequate transparency, increased administrative burden, not providing certainty to participants, and not supporting trials of new technologies to support power system security. The Commission and stakeholders agree the current approach is not an enduring solution.

Instead, we need to ensure the future requirements of the power system are met by providing incentives for new entrants and existing participants to make investment decisions that would see system security provided in the longer term.

The Commission is committed to working towards a net-zero grid and a net-zero economy. To achieve this, we need solutions that focus on supporting the power system through the transition.

The revised approach outlined in this paper ensures the opportunities identified in the OSM rule change process to date continue to be progressed while addressing several issues identified in the draft determination, including the importance of providing long-term investment signals, avoiding complex and irrevocable interactions with the energy spot market, and market power concerns.

## 1.4 The revised approach focuses on improving long-term planning frameworks to achieve a simpler and faster solution

The Improving security frameworks rule change is now focusing on long-term procurement through the existing security planning frameworks to address security needs in the transition, rather than through operational procurement.

This paper outlines how we intend to:

- improve existing system security frameworks, including aligning the inertia framework with the recently evolved system strength framework to ensure they recognise the full benefits of investment options, and removing the exclusion to procuring inertia network services and system strength in the NSCAS framework
- create a new transitional non-market ancillary service (NMAS) which will allow AEMO to procure services that are necessary to support the power system through the transition and cannot currently be procured through long-term planning frameworks
- empower AEMO to enable security services with a whole-of-NEM perspective
- improve directions transparency and cost recovery arrangements.

The Commission considers the revised approach ensures we are delivering the best approach while also preparing us to meet the system needs of the future.

## 1.5 The assessment considers the NEO and the system services objective

### 1.5.1 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.[7] This is the decision-making framework that the Commission must apply.

The NEO is:[8]

> To promote efficient investment in, and efficient operation and use of, electricity services for the longer 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.

7 Section 88 of the NEL.

8 Section 7 of the NEL.

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 1.5.4, as well as any other factors that it considers relevant.

### 1.5.2 The Commission is considering the emissions reduction objective in the NEO

In May 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, with the legislative process currently in train.[9] Amendments are expected to take effect later this year.

In order to prepare for the new component of the NEO, this paper is seeking stakeholder feedback on how this rule change request would affect emissions. In effect, the rule change should efficiently contribute to the achievement of government targets for reducing Australia's greenhouse gas emissions.

Specifically, the following elements of this rule change are likely to have an impact on decarbonisation:

- The framework relies on transmission network service provider (TNSP) procurement using the regulatory investment test for transmission (RIT-T) to meet security needs. The harmonising rule change would, if made, require TNSPs to account for the value of emission reductions in their RIT-Ts. This would apply when TNSPs consider options to meet system security needs under the security frameworks, automatically drawing in emissions considerations.
- Proposing to expand procurement eligibility for the minimum threshold of inertia to include synthetic inertia, which would provide greater incentives to zero-carbon sources.
- AEMO would be responsible for operational scheduling of planning timeframe contracts, which would be designed to:
  - ensure sufficient security services are available to host projected IBR.
  - promote efficient activation of planning timeframe contracts, by avoiding activating contracts when they are not required and thus potentially reducing emissions (because many early providers of security services will be emissions-intensive plant).

The Commission is seeking stakeholder views on how to consider the upcoming emissions component of the NEO in relation to this rule change. We will use an emissions reduction criterion as part of the assessment framework for this rule change when the change to the NEO becomes law.

### 1.5.3 The Commission is also considering the system services objective

The system services objective was set out in the consultation paper and draft determination, and has been developed by the Commission in relation to assessment of system services rule

9 Department of climate change, energy and environment and water, 2023. Energy and climate change ministerial council meeting 19 May 2023 communique, https://www.energy.gov.au/sites/default/files/2023-05/EMSG1%20final%20communique%2019%20May%202023_0.docx.

changes. It reflects the trade-offs that are expected when considering issues related to the provision of system services.

The system services objective seeks to:

> Establish arrangements to optimise the reliable, secure and safe provision of energy in the NEM, such that is it provided at efficient cost to consumers over the long-term, where 'efficient cost' implies the arrangements must promote:
>
> • efficient short-run operation of,
>
> • efficient short-run use of, and
>
> • efficient longer-term investment in, generation facilities, load, storage, networks (i.e. the power system) and other system service capability.

Achieving dynamically efficient outcomes, given these attributes, will require flexible regulatory frameworks.

### 1.5.4 The Commission proposes to assess this rule change using these eight criteria

#### Our regulatory impact analysis methodology

Considering the NEO and the issues raised in the rule change request, the Commission proposes to assess this rule change request against the set of criteria outlined below. These assessment criteria reflect the key potential impacts — costs and benefits — of the rule change request.

The Commission's regulatory impact analysis may use qualitative and/or quantitative methodologies. The depth of analysis will be commensurate with the potential impacts of the proposed rule change. We may refine the regulatory impact analysis methodology as this rule change progresses, including in response to stakeholder submissions.

Consistent with good regulatory practice, we also assess other viable policy options — including not making the proposed rule and making a more preferable rule — using the same set of assessment criteria and impact analysis methodology where feasible.

#### Assessment criteria and rationale to help promote the NEO

The Commission considers the following criteria relevant for understanding how the proposed revised approach promotes the NEO:

- **Promoting power system security**: The operational security of the power system relates to the maintenance of the system within pre-defined limits for technical parameters such as voltage and frequency. It is necessary to have regard to the potential benefits associated with improvements to system security brought about by the proposed rule changes, weighed against the likely costs.
- **Emission reduction impacts**: The rule change should efficiently contribute to the achievement of government targets for reducing Australia's greenhouse gas emissions. (Note that we will apply this criterion if and when the law changes to include emission reduction targets in the NEO take effect.)

- **Appropriate incentives and risk allocation:** The allocation of risks and the accountability for investment and operational decisions should rest with those parties best placed to manage them.
- **Timely and appropriate mechanism for security**: The power system's rapid transition is already underway, and tools to support system security need to be in place in time to help manage the transition. Tools need to be appropriate to the issue being managed, with market-based tools likely to be most efficient where practicable.
- **Transparency, predictability and simplicity**: The market and regulatory arrangements should promote transparency and be predictable, so that market participants can make informed and efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to administer and participate in.
- **Technology neutrality:** Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind.
- **Flexibility and consistency** with broader reform: Regulatory arrangements must be flexible to changing market and external conditions, and consistent with the direction of broader reform. Arrangements must be able to remain effective in achieving security outcomes across the NEM over the long-term in a changing market environment.
- **Implementation costs and complexity**: Regulatory change typically comes with some implementation costs for regulators, the market operator and/or market participants. These costs are ultimately borne by consumers. The cost of implementation should be factored into the overall assessment of any change. Increased complexity comes with increased costs, and therefore the level of complexity of regulatory change should be justified by the benefits achieved.

## 1.6 How to make a submission

### 1.6.1 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.

### 1.6.2 How to make a written submission

**Due date**: Written submissions responding to this directions paper must be lodged with Commission by **5pm, 28 September 2023**.

How to make a submission: Go to the Commission's website, [www.aemc.gov.au](www.aemc.gov.au), find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **ERC0290.**[10]

10 **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.**

Tips for making submissions on rule change requests are available on our website.[11]

**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).[12]

### 1.6.3 Next steps and opportunities for engagement

Given the change of policy direction from the draft determination, the Commission extended the time frame for a final determination to **21 December 2023**.

We plan to continue the technical working group meetings to assist us in the development of the final determination and rule. Additionally, we are eager to hold one-on-one or small group meetings with any interested stakeholders. If you wish to join the technical working group or want to request a meeting with the project team, please contact the project leader through the project page or at the email below.

### 1.6.4 For more information, you can contact us

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

Project leader: Nomiky Panayiotakis

Email: nomiky.panayiotakis@aemc.gov.au

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

12 Further information is available at https://www.aemc.gov.au/contact-us/lodge-submission

# 2 THE COMMISSION IS RESPONDING TO STAKEHOLDER FEEDBACK ON THE DRAFT DETERMINATION

### BOX 2: KEY POINTS IN THIS CHAPTER

- The Commission's draft determination proposed implementing an OSM which would have co-optimised the procurement of security services, energy and FCAS, and operated parallel to the spot market.
- Stakeholder feedback to the OSM draft determination raised material concerns.
- Following stakeholder feedback the Commission decided on a revised approach for the OSM.
- The revised approach aims to deliver simpler and more timely solutions.
- This will avoid many of the fundamental issues raised about the mechanism's ability to promote long-term investment and avoid energy market distortions, as well as the specific design issues that would potentially take significant time to work through.
- The revised approach is based on amending the existing security frameworks so they are comprehensive enough to allow for the procurement and scheduling of the necessary security services and avoid reliance on directions to maintain security.

In submissions to the draft determination, stakeholders broadly supported taking action to ensure a more efficient and transparent approach, other than directions, to manage system security. However, submissions raised a number of questions and material concerns about the fundamentals of the design and objective of the OSM and the details of the draft rule. This led the Commission to propose a revised direction that was simpler and would achieve the objectives faster.

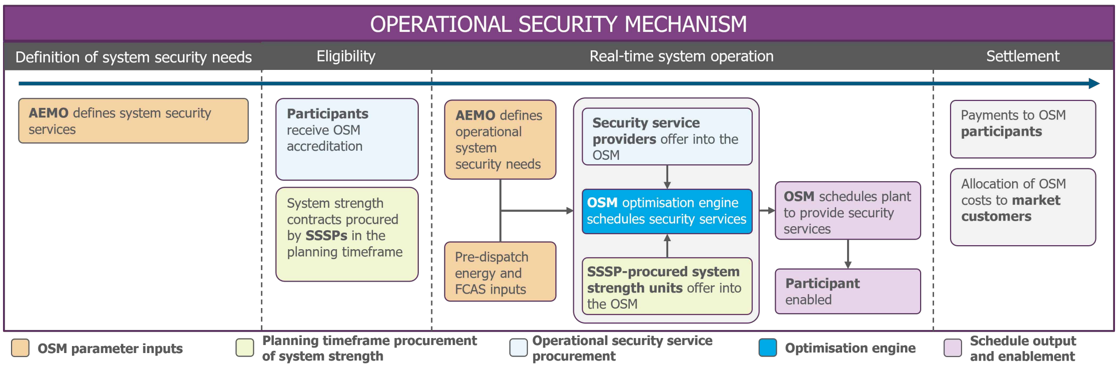
This section outlines the key features of the OSM design in the draft determination, and explains how stakeholder feedback and the Commission's consideration of issues raised by the draft determination have led to the revised direction. This section sets out:

- Section 2.1 — The Commission's draft determination proposed implementing an OSM
- Section 2.2 — Stakeholder submissions raised material concerns about the draft determination
- Section 2.3 — The Commission has revised the direction of the rule change based on stakeholder feedback

## 2.1 The Commission's draft determination proposed implementing an OSM

Following stakeholder feedback from the 2021 directions paper, the AEMC proposed a draft rule that would have introduced a mechanism known as the Operational Security Mechanism (OSM). The OSM would have co-optimised the procurement of security services, energy and FCAS, and would have operated parallel to the spot market. The design is outlined in detail in the OSM draft determination.[13]

**Figure 2.1: Operational security mechanism**




Source: AEMC, Operational security mechanism — draft determination

### 2.1.1 The OSM would have procured and scheduled security services to maximise the value of trade

The OSM would have procured and scheduled security services that are not already procured through a market. This would have included:

1. system configurations that are being used by AEMO to manage the power system and provide security services.
2. 'unbundled' system services as they became known and manageable, such as inertia. It would not have included frequency, which is already procured through the co-optimised FCAS markets.

Where network service providers (NSPs) have entered into contracts (non-network options) to meet identified system services needs, e.g. system strength, such contracts would have been scheduled and enabled through the OSM.

The OSM's objective function would have sought to maximise the value of trade across security services, energy and FCAS. This means that the OSM's optimisation engine would:

- select the lowest-priced security services to meet minimum security levels
- procure and schedule additional security services above the minimum levels if it would lower costs in other markets.

13 See Section 3 of the OSM Draft Determination for a summary of the proposed design, with detailed design discussions in Sections 4-11.

For example, if additional system strength could alleviate a security constraint and enable more low-cost renewable energy generation, then the OSM would have scheduled the additional resources to provide that system strength.

Importantly, a key principle of the OSM was that it would never schedule security services for the sole purpose of reducing energy costs. If it did, the OSM would distort the 5-minute wholesale energy market by committing units for energy ahead of time, compromising energy price signals. However, in scheduling for security, the OSM would have had a strong (and intentional) interrelationship with the energy market because of the OSM's objective function to maximise the value of trade across the energy, FCAS and security markets.

### 2.1.2 The OSM would have used real-time procurement and scheduling rather than long-term contracts

All accredited market participants would have had the option to bid into the OSM — however, bidding would not have been mandatory.

If enabled, accredited market participants would have received OSM revenue according to their bid, known as a 'pay-as-bid' arrangement. For participants that provide energy as a by-product of providing security services, the OSM revenue would have only applied to the energy production associated with the unit's provision of security services. For example, a unit might have earned OSM revenue according to its minimum generation only — any additional energy provided would be paid at the spot market price.

Participants would have been able to submit bids up to three weeks in advance, which would have aligned with the timings for the energy and FCAS markets. To assist participants in positioning and re-positioning their assets across the energy market and the OSM, AEMO would have published iterative OSM schedules based on participant bids and rebids. AEMO would have enabled OSM participants as close to dispatch as reasonably practicable.

The costs of OSM payments would have been recovered from market customers, taking into account regional benefits and customers' proportions of load.

### 2.1.3 The potential for market power under the OSM would have been reviewed by the Australian Energy Regulator (AER)

The Commission considered that market power could have been exercised in the OSM to increase prices due to a limited number of system configurations or participants in certain regions. To mitigate this, the draft determination set out that the AER would have:

- assessed whether there was any potential for the exercise of a substantial degree of power in the OSM
- provided recommendations to AEMO to implement specific mitigation measures based on the market power identified.

Mitigation measures that could have been recommended by the AER included price caps applied to OSM bids or price monitoring to track whether market power was being exercised. The AER would have had the flexibility to choose how any price caps would be implemented — for example, applying them over specific regions, participants, or bid components.

## 2.2 Stakeholder submissions raised material concerns about the draft determination

In submissions to the draft determination, stakeholders broadly supported taking action to ensure a more efficient and transparent approach other than directions exists to manage system security. However, submissions raised a number of questions and material concerns about the fundamentals of the design and objective of the OSM and the details of the draft rule.

Some submissions supported the proposed approach in principle, but raised significant design issues with the mechanism.[14] Others did not support the approach, preferring alternatives such as long-term contracting for security services[15] or waiting to see how current reforms including the new system strength framework played out in supporting system security[16] before going ahead with a complex new market mechanism.

### 2.2.1 The OSM design in the draft determination was unlikely to provide the intended long-term investment signals for security

***Operational procurement of a service that is difficult to define would be unlikely to provide clear and predictable long-term investment signals for participants***

There is currently a lack of clear, predictable investment signals to incentivise the provision of security services in the NEM. The Commission considers it is particularly important to create incentives for parties to invest and innovate in equipment that provides system security, particularly given the rapid exit of synchronous generators and the need to replace their security services with new technology.

The OSM draft determination aimed to address this by providing operational price signals through close-to-real-time procurement. It then relied on such signals to incentivise long-term investment decisions. However, these price signals are not particularly meaningful if there is no corresponding service definition that they relate to. AEMO is currently managing system security through system configurations, where it requires a particular asset's presence online to support system security. This does not give useful information to investors as to what *capabilities* or *service* would be potentially valuable to invest in.

Many stakeholders commented in submissions to the draft determination that the lack of a clear service definition prevented the proposed design from providing the intended incentives. For example, the AEC was concerned that there was not a simple enough commodity for an investor to interpret.[17] Similarly, Tesla was concerned that left undefined, familiar technologies would be favoured and not allow for new providers/services.[18]

The Commission concluded that as long as system configurations are relied on, the original OSM design would have supported existing assets to provide security services operationally,

14 e.g. Enel Green Power, submission to the draft determination.
15 e.g. Clean Energy Council, submission to the draft determination.
16 e.g. TasNetworks, submission to the draft determination.
17 AEC, submission to the draft determination.
18 Tesla, submission to the draft determination.

but not necessarily provided reliable incentives for investment in new plant or equipment or innovation in the delivery of system security.

AEMO outlines in its [2022 Engineering Roadmap to 100% Renewables] that it currently manages operational security through system configurations. AEMO expects to continue using configurations to manage security into periods where the system operates at 100% renewables, and considers further work is required over coming years to evaluate whether separately defining and managing operational security requirements is technically feasible.[19]

AEMO cannot currently specify system security services in operational timeframes. Due to this, it is managing the system through known configurations. Given this, the Commission sees little merit in pursuing operational, real-time market-based solutions. Indeed, pursuing such an approach could result in unintended consequences given that the price signals do not relate to the service.

This is unlikely to deliver the intended long-term investment signals for security.

***'Pay as bid' may not provide sufficient incentives to deliver system security in an efficient way***

The OSM draft determination proposed a 'pay as bid' structure (where parties are paid the price they bid at for security provision). This approach is sensible for services that are not homogenous, as is the case for system security configurations. It would not be meaningful to develop a common clearing price based on marginal service provision for participation in configurations, as there is no concept of a marginal extra unit of security service where the asset is either on (and thus providing security services in a configuration) or off. This means that a marginal price cannot provide clear signals of the value of security provision to the system — an operator or potential investor could not use a marginal price to understand their own potential revenue streams from different operational or investment decisions.

Some stakeholders, for example Delta Energy and the AEC,[20] considered that a pay-as-bid approach would not deliver system security in an economically efficient way and so would not provide effective investment signals to incentivise entry. The AEC considered that 'pay as bid' approaches are unstable, and unintuitively result in higher costs to consumers. Stakeholders were mixed in their views on what the alternative means should be. Some, for example CS Energy, considered that marginal pricing for unit configurations was possible and meaningful.[21] The Commission does not agree for the reasons stated above. Others, for example the Clean Energy Council[22], noted the benefits of long-term contracts in providing stable revenue streams to new investments, and considered this was not provided by the OSM.

19 AEMO, Engineering Roadmap to 100% Renewables, 2022, p 28. https://ameo.com.au/-/media/files/initiatives/engineering-framework/2022/engineering-roadmap-to-100-per-cent-renewables/pdf?la=en

20 Delta Energy, Australian Energy Council, submissions to the draft determination.

21 CS Energy, Submission to the draft determination.

22 Clean Energy Council, submission to the draft determination.

### 2.2.2 The proposed operational procurement and scheduling arrangements would alter signals in the energy spot market and decrease its efficiency

The OSM proposed in the draft determination was intentionally designed to interact with the energy spot market. OSM participants would bid to provide security services close to real time, and an OSM engine would use expected energy and FCAS pre-dispatch information to identify security gaps and any opportunities to maximise the value of trade across the markets. OSM providers would reflect their likely OSM enablement in their energy market bids, and then non-OSM energy market participants could reposition energy offers in response to the OSM outcomes. This process would then repeat over multiple OSM runs, and in theory the energy market and OSM outcomes would iterate and converge to an efficient solution. Security services would have been committed as close to real-time as practicable, but a certain amount of 'aheadness' was inevitable, given current operational engineering knowledge.

The Commission designed these arrangements carefully with the intention that the OSM would minimise distortions to spot market outcomes. However, after further deliberation and considering stakeholder feedback, the Commission has concluded that some level of distortion is unavoidable with the OSM.

The OSM set out in the draft determination would introduce a new market with potentially significant adverse impacts on the energy spot market. It would introduce 'aheadness' (where units are committed ahead of real time) in unit commitment decisions for a potentially significant subset of the market — conceivably, for example, all thermal units (which have historically supported system security and form part of many system configurations) could have chosen to participate in the OSM. This aheadness would have diluted the effectiveness of the spot market signal, reducing its efficiency and distorting incentives for participation in that market. The Commission also considers it possible that there could have been potential gaming opportunities between the different markets created through this aheadness, however, did not explore this in depth.

To avoid energy market distortions, the OSM was also proposed to only commit units for security, and not to allow 'energy only' commitments. This refers to situations where units would be committed by the OSM ahead of time simply because they lowered the overall price of dispatch — thus unintentionally creating an energy ahead-market. The Commission understands that ensuring that units were not committed for energy presented potential difficulties in implementation[23] and considered that these would likely have been complex to work through and come to a solution that adequately avoided the risk of energy-only commitments.

The OSM also had the potential to produce unintended increased costs to consumers due to the interaction between 'disorderly bidding' and the OSM's objective function. Disorderly bidding occurs when market participants bid in a manner that is not economically efficient in an operational sense due to other factors. The AER explained this issue in its submission to the draft determination.[24]

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23 Market Reform and AEMO, Operational Security Mechanism Modelling Findings Report, 2023, p 5.

24 AER submission to the draft determination.

The OSM was designed to maximise the value of trade on the basis of offered prices into the energy market by generators. These offer prices may not reflect actual settlement prices, because of the regional pricing model used in the NEM. For example, generators behind a constraint can bid at the market price floor (-$1000/MWh) to maximise their chances of dispatch, without changing the regional reference price that they receive. If the OSM paid to relieve these constraints on the basis of the low offer prices, but this did not change the regional reference price, then costs to consumers would be increased.

### 2.2.3 Market power concerns arise in operational procurement of system configurations

The Commission considers that, due to the locational characteristics of supplying security services, the OSM may have been prone to instances of market power, which can arise when a firm has the ability to set and maintain prices at inefficiently high levels when it sells a good or service. This could then flow through into higher costs for consumers.

Market power concerns are likely to be difficult to manage where there are limited participants in system configurations. For instance, while there are multiple potential system configurations which would be used in each jurisdiction to manage system security, some units feature frequently in many configurations. The OSM draft determination presented some simple analysis of unit configurations in South Australia[25] showing that three portfolios (AGL, Engie and Origin) all participate in a majority of configurations in South Australia. This illustrates that there may be some situations where suppliers of ESS for minimum system configurations in South Australia may have market power, particularly if there are changes to the availability of units, for example, through planned or unplanned outages. TasNetworks agreed that market power may be a concern initially and noted that Hydro Tasmania is required for all system configurations in Tasmania.[26]

The Commission considers that market power may be difficult to manage in operational procurement of system security, because providers of security are aware of their crucial role in security and can see whether alternatives are available or not through pre-dispatch. The Commission proposed a method to manage market power in the draft determination — however, the AER had concerns about the scale of their role in helping address market power.[27] Market power concerns were likely to be exacerbated in the near-term due to ongoing retirements of synchronous generators and the ongoing use of system configurations.

### 2.2.4 Stakeholders raised many questions on how the OSM would work in practice

Many stakeholders raised questions about how the OSM would work in practice. Submissions that supported the OSM approach generally raised substantive concerns with design aspects of the OSM, which would have been complex and time-consuming to solve. This may have delayed the implementation of the mechanism beyond the envisaged timeframes, reducing its effectiveness in supporting the system through the transition.

25 OSM draft determination, p 45.

26 TasNetworks submission to the draft determination, p 3.

27 AER submission to the draft determination.

One area of particular concern from stakeholders was the OSM's interaction with the system strength framework. The OSM would have scheduled any contracts NSPs entered into in planning timeframes with resources to provide system services, such as system strength contracts procured under the new system strength framework. This meant providers of system strength would have been compensated by the OSM for activation costs, and by system strength service providers (SSSPs) for any further costs under the contract (for example, ongoing availability payments). SSSP cost recovery for system strength was proposed to build on the system strength framework to prevent SSSPs from being compensated twice for providing the same service.

However, compensating units for their variable costs through the OSM framework would have moved these costs out of the system strength framework and onto market customers. The ENA and TasNetworks expressed support for this approach[28] as it would have relieved TNSPs of managing operational costs, but requested clarification as it created complexities with cost recovery and had the potential to undermine the incentives and intent of the system strength framework.

To avoid double-charging for system strength, this approach of moving activation costs onto market customers would mean that connecting parties should not be charged under the system strength framework forward-looking charging mechanism for these costs. However, there are two issues with this approach:

- Not charging connecting parties for the full impact of their increased system strength demand would reduce the incentives in the system strength framework to incorporate system strength impacts in connection decisions.
- It would be complex to adjust the system strength framework to avoid double-charging for system strength. The OSM did not include this adjustment.

Stakeholders also raised many questions about the mechanism design overall, including specific concerns relating to all design aspects of the mechanism. Feedback included:

- Energy Australia, the AEC and CS Energy[29] proposed services be defined through a process involving the Reliability Panel, and Energy Australia[30] felt AEMO should be required to specify service definitions (moving away from system configurations) before the OSM commenced.
- Origin, the AEC and the AER[31] proposed to refocus the objective function on minimum secure services to avoid potential perverse outcomes. Thermal generators noted that being unable to access energy prices after OSM enablement would make defending contracted positions challenging and could create challenging interactions with the energy market. Delta Electricity was particularly concerned that this risk would increase the price of forward contracts while reducing the volume available to the market.

28 TasNetworks, Energy Networks Australia, submissions to the draft determination.
29 Energy Australia, AEC, CS Energy, submissions to the draft determination.
30 Energy Australia, submission to the draft determination.
31 Origin Energy, Australian Energy Council, AER, submissions to the draft determination.

- Enablement payments, as well as the eligibility rules, were seen as incentivising plant to falsely decommit to receive revenue.[32]

## 2.3 The Commission has revised the direction of the rule change based on stakeholder feedback

After carefully considering stakeholder feedback and the issues raised the Commission considers the OSM — and its arrangements for operational procurement and scheduling of security services — would be costly and complex to implement.

The Commission also considers that it is important to have greater engineering and operational understanding of the power system before introducing any complex market changes. Our understanding of system security needs through the transition is still developing. It is yet to be seen how new technologies will contribute to security and whether system services can be individually defined in operational timeframes.

The Commission is therefore proposing a revised approach to deliver simpler and more timely solutions. This would avoid many of the fundamental issues raised about the mechanism's ability to promote long-term investment and avoid energy market distortions, as well as the specific design issues that would potentially take significant time to work through. The revised approach is based on amending the existing security frameworks so that they are comprehensive enough to allow for the procurement and scheduling of the necessary security services and avoid reliance on directions to maintain security.

This would allow a solution to address the need for power system security sooner, building on existing security frameworks (including inertia, system strength, and NSCAS, as well as a proposed new transitional services framework) to allow procurement of security services for known configurations and for trialling new methods of delivering system security.

Considered together, these solutions focus on addressing the needs of the power system today and aim to support power system security through the transition to 100% instantaneous IBR. The Commission considers the revised approach would promote the NEO by focusing on ensuring a smooth and efficient transition to a new operating environment. We are seeking to build on these existing arrangements to put in place simpler and more flexible solutions compared with the tool outlined in the draft determination. This ensures we are delivering the best approach based on the information we know today, while also preparing us to meet the system needs of the future.

## 2.4 AEMO's prototyping work has been integral to our assessment

In early 2023, AEMO provided a prototyping final report to the AEMC.[33] AEMO's analysis of an OSM model included exploring how the OSM interacts with the NEM pre-dispatch and participant decision-making, as well as the impact of various scheduling parameters (for example, simulation horizon and resolution).

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32 Australian Energy Council, submission to the draft determination.

33 AEMO's prototyping final report can be found at https://www.aemc.gov.au/sites/default/files/2023-05/AEMO%20OSM%20Prototyping%20Final%20Report%20%281%29.pdf.

The AEMC acknowledges the important analysis undertaken by AEMO on the design of an OSM. The model was developed to inform the OSM final solution. This prototyping work has provided significant value to the AEMC in progressing this rule change further by enhancing the Commission's understanding of an OSM model and formulation.

# 3 IMPROVEMENTS TO EXISTING SYSTEM SECURITY FRAMEWORKS

## BOX 3: KEY POINTS IN THIS SECTION

The Commission proposes several improvements to the inertia and NSCAS frameworks to better support system security, economic efficiency and reduce the need for market intervention or directions.

**Introducing a mainland inertia floor**

- The current inertia framework does not recognise inertia requirements during interconnected operation to manage system rate of change of frequency (RoCoF) and transient stability. It may also result in unbalanced procurement which would mean some regions of the NEM under-invest while others bear a disproportionate burden.
- The Commission proposes introducing a mainland inertia floor for interconnected operation to promote distributed and proactive inertia procurement.
- AEMO would set the inertia floor with regard to the RoCoF limit for credible contingency events in the Frequency Operating Standard (FOS), the level of inertia required to maintain security without relying on market interventions, and any other matters as AEMO sees fit.
- AEMO would allocate proportions of the inertia floor across the regions of the mainland NEM according to regional inertia needs and other factors to promote balanced TNSP procurement.
- The inertia floor would complement the existing inertia shortfall framework, to ensure that inertia sub-networks at risk of separation can procure higher levels of local inertia to operate as an island.

**Aligning inertia and system strength procurement timeframes**

- The Commission proposes that AEMO would be required to project inertia needs for all sub-networks over 10 years, including the inertia floor for interconnected operation and the secure operating level.
- TNSPs would be required to ensure that sufficient inertia is continuously available, three years into the future. This mirrors the current system strength obligations.
- The proposed changes would commence on 1 December 2024, meaning that binding procurement of the mainland inertia floor would commence from 1 December 2027.

**Enabling TNSP procurement of synthetic inertia to meet the minimum threshold level**

- The Commission proposes to widen the eligibility of units capable of meeting the minimum threshold level of inertia beyond synchronous sources.

- TNSPs would be able to procure synthetic inertia to meet the minimum threshold level, subject to AEMO approval.
- AEMO would be required to consult on and publish a detailed specification of the required capabilities of synchronous and synthetic inertia providers.

**Removing the exclusion of inertia and system strength under NSCAS**

- Currently, there is no backstop procurement mechanism to procure inertia and system strength services if a shortfall emerges prior to the three-year compliance window.
- The Commission proposes to allow inertia and system strength services to be procured through the NSCAS framework.
- The inertia and system strength frameworks would remain the primary mechanisms for the procurement of those services — the NSCAS framework would only be used as a backstop procurement mechanism.
- The Commission is also proposing that a RIT-T would not be required if AEMO requires inertia network or system strength services to be provided less than 18 months after an NSCAS gap is declared.

## BOX 4: QUESTIONS FOR STAKEHOLDERS IN THIS CHAPTER

**Introducing an inertia floor for the mainland NEM for interconnected operation** (see section 3.3)

- Do stakeholders support the Commission's proposal to introduce an inertia floor for the mainland NEM?
- Do stakeholders consider that the allocation of proportions of the floor across the NEM would promote balanced and proactive procurement?

**Alignment of the inertia and system strength procurement timeframes** (see section 3.4)

- Do stakeholders support the Commission's proposal to require AEMO to project inertia needs for all sub-networks every 10 years?
- Do stakeholders support requiring TNSPs to ensure that sufficient inertia is continuously available, based on the three-year compliance period?

**Widening the eligibility of units capable of providing inertia** (see section 3.5)

- Do stakeholders agree with the Commission's proposal for TNSPs to be able to procure synthetic inertia to meet the minimum threshold level?
- Do stakeholders agree with the requirement for AEMO to consult on and publish a specification of synchronous and synthetic inertia?

**Removing the exclusion on inertia and system strength in the NSCAS framework**

(see section 3.6)

- Do stakeholders agree with the Commission's proposed approach to remove the current exclusion on inertia and system strength in the NSCAS framework?

**RIT-T exemption** (see section 3.6)

- Do stakeholders think should a RIT-T exemption should apply to inertia and system strength services where a shortfall arises within 18 months?

**Commencement arrangements** (see section 3.7)

- Do stakeholders agree with the proposed commencement arrangements?
- Are there extra factors that the Commission should consider in transitioning to the new inertia arrangements?

This section covers the Commission's proposed improvements to existing planning timeframe system security frameworks to facilitate the secure transition of the power system to an IBR-dominated grid, including:

- Section 3.1 — The Commission proposes **three** changes to ensure inertia procurement is forward-looking, balanced, and open to new technologies
- Section 3.2 — These changes would address issues and promote opportunities in the current inertia arrangements
- Section 3.3 — An inertia floor would promote system security and economic efficiency by distributing procurement around the NEM
- Section 3.4 — Aligning inertia and system strength procurement timeframes would allow TNSPs to more efficiently coordinate investment
- Section 3.5 — Enabling TNSP procurement of synthetic inertia to meet the minimum threshold would promote system security and economic efficiency
- Section 3.6 — The Commission proposes to remove the exclusion on procuring inertia and system strength under the NSCAS framework
- Section 3.7 — The Commission proposes that most changes to the inertia and NSCAS frameworks would commence on 1 December 2024
- Section 3.8 — These arrangements would help promote system security and reduce the use of directions

## 3.1 The Commission proposes three changes to ensure inertia procurement is forward-looking, balanced, and open to new technologies

This Commission proposes three main changes to the existing inertia framework (described further below), which together should result in a more secure power system, a more proactive and simple approach to meeting system needs as the generation fleet decarbonises and a more cost-effective outcome for consumers. These three proposed changes are:

1. **Introduction of a mainland inertia floor** (section 3.3) — the rules would introduce a new mainland inertia floor to ensure that minimum system needs for interconnected operation would be proactively met through balanced procurement in all mainland regions of the NEM.
2. **Alignment of procurement timeframes** (section 3.4) — the rules would align the forecasting and procurement timeframes of the system strength and inertia frameworks, allowing for transmission network service providers (TNSPs) to more efficiently coordinate system strength and inertia needs when considering network or non-network solutions.
3. **Removing restrictions on the procurement of synthetic inertia** (section 3.5) — the rules would make synthetic sources of inertia eligible to provide the minimum threshold level (subject to AEMO's approval), encouraging greater investment in zero-carbon sources of security services to meet system needs as synchronous units continue to retire.

The Commission is seeking stakeholder feedback on these proposed changes. Importantly, the revisions seek that the reliance on market interventions such as that seen in South Australia is not replicated in other regions of the NEM. We seek to avoid this outcome by having system security needs met through forward-looking long-term procurement frameworks ahead of the retirement of synchronous generators.

The Commission notes that following the completion of this rule change, we will consider operational procurement of inertia through the *Efficient provision of inertia* rule change.[34]

## 3.2 These changes would address issues and promote opportunities in the current inertia arrangements

The *Managing the rate of change of power system frequency* rule change introduced the current inertia framework in 2018. The framework seeks to manage any inertia shortfalls in sub-networks at risk of separation from the wider NEM. This section provides an overview of how the inertia framework works, and issues that have been identified with the framework as well as opportunities to improve it.

> **BOX 5: WHAT IS INERTIA?**
>
> Inertia can be defined as an object's resistance to any change in its momentum. Inertia is important in the power system as this resistance to change helps to maintain frequency and voltage within the technical limits of a secure and stable power system. The greater the inertia on the power system, the less vulnerable it is to disturbances, all else kept equal.
>
> For example, inertia limits the rate of change of power system frequency following a sudden change in the balance of generation and load on the power system, such as caused by a large generator disconnecting from the power system. The NEM operates at a frequency range as close to 50 Hertz (Hz) as possible, meaning the power system safely and securely transmits

34 See: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia.

power from generators to consumers. When there is more inertia on the power system, frequency changes more slowly. This allows more time for frequency control services, such as primary frequency response and FCAS, to address the energy imbalance and arrest the change in frequency.

In a similar manner, inertia also supports a stable voltage waveform by dampening oscillations in active power and so can contribute to system strength.

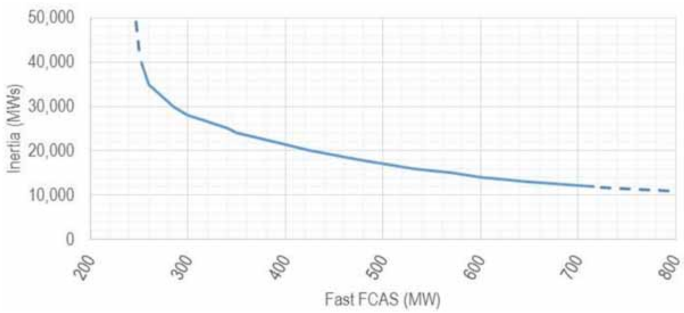
A synchronous inertial response is the electromechanical inertial response from stored kinetic energy in the rotating mass of a machine that is electromagnetically coupled to the power system's voltage waveform at 50 Hz. Generators with large spinning turbines (such as coal, gas or hydro plants) or a synchronous condenser can provide synchronous inertial responses, and are called 'synchronous generators' or 'synchronous machines'.

A synthetic inertial response is the emulated inertial response from an inverter-based resource that is inherently initiated in response to a power system disturbance. It is sufficiently fast and large enough to help manage the rate of change of frequency. Some grid-forming inverters and systems are capable of providing synthetic inertia.

While fast frequency response (FFR) may appear similar to synthetic inertia, AEMO considers that fast frequency response 'may require external measurements of frequency to initiate an active power response,' while synthetic inertial responses are inherent and may not require external measurements.

Although fast frequency response is not equivalent to inertia, it can help reduce the amount of inertia that the power system requires for secure operation. A power system with higher volumes of fast frequency response requires less inertia to arrest large changes in frequency, while a system with a lower volume of FFR requires more inertia (see Figure 3.1). This trade-off means that FFR can be procured to help meet inertia shortfalls through 'inertia support activities' as described in section 3.2.1.

**Figure 3.1: Plot of inertia-FFR trade-off**




Note: The material in this box has been adapted from AEMO's 'Inertia in the NEM explained' document.

### 3.2.1 Overview of the current inertia framework

The current inertia framework commenced in 2018 to ensure minimum levels of inertia are available to keep the NEM secure. It does this by ensuring there is enough inertia available in any regions at risk of separation ('islanding') from the rest of the NEM so that the region can continue to operate securely as an island following a separation event. Under the current framework:

1. AEMO declares inertia sub-networks, taking into account whether the sub-network is at risk of islanding
2. AEMO determines the inertia requirements for each sub-network, and whether any sub-networks are projected to have inertia shortfalls
3. TNSPs must procure inertia to meet any shortfalls.[35]

#### AEMO declares inertia sub-networks

Under NER clause 5.20B.1, AEMO must determine the boundaries of inertia sub-networks, taking into account:[36]

- the synchronous connections between the proposed sub-network
- the likelihood of the proposed sub-network being islanded
- the criticality and practicality of maintaining the proposed inertia sub-network in a satisfactory operating state if it is islanded and being able to return to a secure operating state while islanded.

Currently, all inertia sub-networks align with NEM regional boundaries.

#### AEMO determines inertia requirements of each sub-network and any shortfalls

AEMO is required to assess inertia sub-networks and requirements for each region of the NEM[37] and declare any identified shortfalls or gaps for the coming five-year period.

For all inertia sub-networks, AEMO projects the:

- minimum threshold level of inertia — the minimum level of inertia required to ensure the sub-network remains in a satisfactory operating state when islanded[38]
- secure operating level of inertia — the minimum level of inertia required to ensure the sub-network remains in a secure operating state when islanded.[39]

AEMO determines whether there are inertia shortfalls in the system by assessing:[40]

- the extent to which inertia typically provided in the sub-network is, or is likely to be, below the secure operating level

35 See: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-frequency

36 The rules specify that the boundaries of an inertia sub-network must be aligned with the boundaries of a region or wholly confined within a region.

37 NER, clause 5.20B.2.

38 NER, clause 5.20B.2(b)(1)

39 NER, clause 5.20.B.2(b)(2).

40 NER, clause 5.20B.3(b).

- inertia levels typically provided in adjacent inertia sub-networks and the likelihood of the inertia sub-network becoming islanded
- any other matters that AEMO reasonably considers relevant in making its assessment.

**TNSPs are required to make sufficient inertia continuously available to meet any declared shortfall**

For inertia sub-networks in which AEMO declares a shortfall, TNSPs must make continuously available sufficient inertia or alternative frequency control services to meet the projected need. AEMO must specify by when the inertia will be required in its report, but any shortfall must not be earlier than 12 months after the notice is published.[41]

TNSPs can propose network or non-network solutions to provide inertia to meet the shortfall — for example, by installing synchronous condensers with high inertia flywheels, entering into contracts with synchronous generators, or procuring FFR.[42] These solutions are subject to a RIT-T, assessing which is the solution that addresses the need that has the highest net benefit.[43]

**TNSPs can only procure synchronous inertia to meet the minimum threshold level**

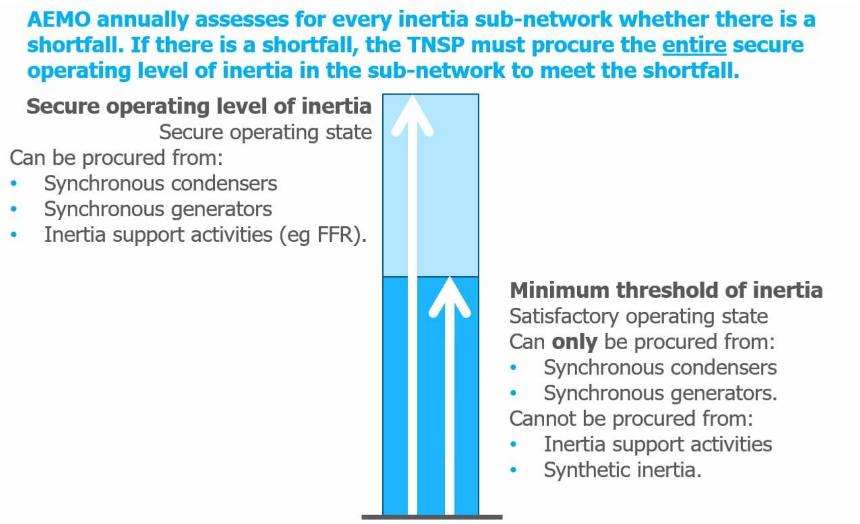
TNSPs must meet the minimum threshold level using synchronous inertia provided by the rotating masses of synchronous condensers or generators. The remaining inertia (to meet the secure operating level) can be provided by either synchronous inertia or other 'inertia support activities' (for example, through procuring FFR).

41 NER, clause 5.20B.3(c).

42 This refers to fast frequency response procured through a contract, and not the new *very fast raise* or *very fast lower* ancillary services commencing on 9 October 2023.

43 An important exception to note is that if the TNSP is required to make inertia services available in less than 18 months, then the proposed solutions are not subject to a RIT-T (NER, clause 5.16.3(10)(ii)). The Commission proposes to retain this in the new framework, with the exception applying to inertia services procured through the NSCAS framework to meet a need in less than 18 months after AEMO declares an NSCAS gap — see section 3.6.

**Figure 3.2: Eligibility of sources to meet the minimum threshold and secure operating levels of inertia**




Source: AEMC

### 3.2.2 Issues and opportunities in the current inertia framework

Stakeholder submissions and the Commission's analysis have identified issues with the current approach and opportunities to promote a proactive and enduring framework to meet system needs. Overall, the framework:

- procures inertia reactively to address gaps rather than proactively to address future system needs in a context where inertia is declining, which increases risks of costly interventions in the operation of the wholesale electricity market
- does not effectively coordinate solutions to address inertia and system strength needs simultaneously, missing out on opportunities for efficiency.

#### Declining inertia in the NEM could compromise the secure operation of the power system

Inertia in the power system has historically been provided by synchronous generators, such as coal, gas, and hydro. Inertia is important in the power system as this resistance to change helps to maintain frequency and voltage within the technical limits of a secure and stable power system.

As the generation mix shifts and system inertia decreases, there is an expectation that post-contingency RoCoF will likely increase. This would likely test the existing operational practices of the power system by compromising the:

- time for FCAS to respond and recover the frequency to normal operating levels

- time for emergency frequency control schemes to operate effectively[44]
- probability that generators remaining online following a contingency event.

AEMO has also noted in its 2022 *Engineering Roadmap to 100% renewables* that a precondition for the first 100% renewable period is the:[45]

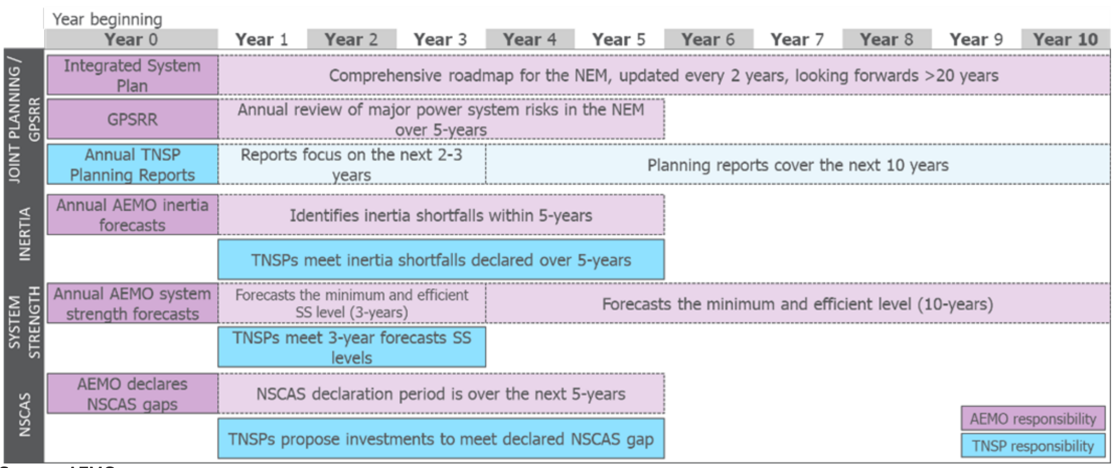
> Ability to keep system frequency within defined limits following credible and non-credible events, including RoCoF containment and effective emergency frequency control arrangements.

As such, given the importance of inertia in maintaining system security, the Commission seeks to establish enduring frameworks to pro-actively and effectively procure inertia to enable the secure decarbonisation of the NEM.

**Misaligned timeframes and procurement triggers for inertia and system strength can result in missed efficiencies**

TNSPs currently procure for inertia and system strength needs according to separate timelines and triggers (see Figure 3.3 below). TNSPs only procure inertia if there is a shortfall — with inertia currently projected 5 years[46] into the future — while they procure system strength up to an 'efficient level', with needs projected over 10 years.[47]

**Figure 3.3: System security framework procurement timelines**




Source: AEMC

44 In rare circumstances following unlikely, or non-credible contingency events, the frequency deviation can be large. If this happens, emergency frequency control schemes may be activated. Under-frequency load shedding (UFLS) is one such scheme implemented to manage a large drop in frequency following an unexpected event that results in too little electricity supply to meet demand.

45 AEMO, Engineering Roadmap to 100% Renewables, December 2022, p 73.

46 NER, clause 5.20.5 currently requires AEMO to forecast inertia shortfalls arising anytime within a planning horizon of at least 5 years.

47 SSSPs are required to meet 10-year forward projections, but AER compliance is based on meeting the rolling 3-year forward projections.

System strength solutions are often able to contribute to providing inertia and vice versa — for example, installing high-inertia flywheels to synchronous condensers installed to meet system strength needs. However, the misalignment of procurement triggers and forecast timeframes mean that TNSPs are not always able to take benefits of both system strength and inertia into account when assessing their options under either framework. This can result in increased costs for consumers, as TNSPs potentially forego incremental investments (like flywheels on synchronous condensers) that could provide significant inertia benefit for little added cost. For example, the installation of high inertia variant synchronous condensers in South Australia provided a total of 4,400 MWs of inertia at an incremental cost of $1m per unit.[48]

Stakeholders[49], AEMO[50] and the AER[51], in their submissions to the AEMC's *Efficient provision of inertia* rule change consultation paper, expressed support for allowing TNSPs to consider inertia benefits in their system strength proposals.

**Limiting inertia procurement to sub-networks at risk of islanding can cause uneven outcomes**

Under the current inertia framework, AEMO is unable to declare shortfalls in regions not at risk of islanding. Restricting procurement to sub-networks at risk of islanding when global inertia is falling results in:

- significant reductions in regions not considered at risk of islanding, compromising system security during interconnected operation
- inertia investment not being well-distributed throughout the NEM with disproportionate allocation of inertia procurement costs between regions.

For example, in its 2022 inertia report (see Figure 3.4 below), AEMO does not declare an inertia shortfall in NSW despite the projected level of inertia falling below the secure operating level, because AEMO does not consider the islanding of NSW from the rest of the NEM to be credible.[52] This increases the inertia procurement burden on Queensland because the prohibition against declaring a shortfall in NSW results in Queensland not being able to rely on additional inertia in NSW. It also means that NSW is more likely to under-invest in inertia solutions while Queensland over-invests, resulting in a sub-optimal inertia distribution with a potential higher cost in the long-term.

48 ElectraNet, Addressing the System Strength Gap in SA – Economic Evaluation Report, 18 February 2019, p 25.

49 Submissions to the efficient provision of inertia consultation paper: Transgrid, p 2; ENA, p 2; TasNetwork, p 2, Iberdrola, pp 5-6;

50 AEMO, Submission to the efficient provision of inertia consultation paper, 31 March 2023, p 3.

51 AER, Submission to the efficient provision of inertia consultation paper, 11 April 2023, p 1.

52 AEMO, 2022 Inertia Report, December 2022, pp 19-22.

**Figure 3.4: 2022 Inertia review outcomes for the NEM, for the five-year period to December 2027**

| New South Wales | Queensland | South Australia | Tasmania | Victoria |
|---|---|---|---|---|
| No shortfall declared, although inertia declines observed in forecast. | New shortfall ranging from 8,200 megawatt seconds (MWs) to 10,352 MWs against the secure operating level, from 1 July 2026. | Existing shortfall is confirmed consistent with the 2021 assessment. | Existing shortfall is confirmed consistent with the 2021 assessment. | New shortfall ranging from 2,421 MWs to 2,482 MWs against the secure operating level, from 1 July 2026 onwards. |

Source: AEMO, 2022 Inertia Report, December 2022, p.3.

### TNSPs are not able to meet the minimum threshold level of inertia by procuring synthetic inertia

As outlined in section 3.2.1 above, for any declared shortfall, TNSPs must rely on synchronous inertia to meet the minimum threshold level. The remainder, up to the secure operating level, can include inertia support activities (such as FFR), subject to AEMO's approval.

These arrangements mean TNSPs cannot source 'synthetic inertia' from inverter-based resources to meet minimum system requirements, which:

- reduces incentives to invest in technologies that provide synthetic inertia
- limits competition to provide the minimum threshold level of inertia, likely increasing costs for consumers.

Although synthetic inertia is still being understood, it is expected that the NEM's future RoCoF needs can be met by a combination of synchronous inertia and synthetic inertia response on the power system.[53] Stakeholder submissions have identified the restriction on the procurement of synthetic inertia to not be in the long-term interests of consumers.[54]

## 3.3 An inertia floor would promote system security and economic efficiency by distributing procurement around the NEM

The Commission proposes introducing a mainland inertia floor for interconnected operation to promote distributed inertia procurement.

53 AEMO, Inertia in the NEM explained, March 2023, p 4.

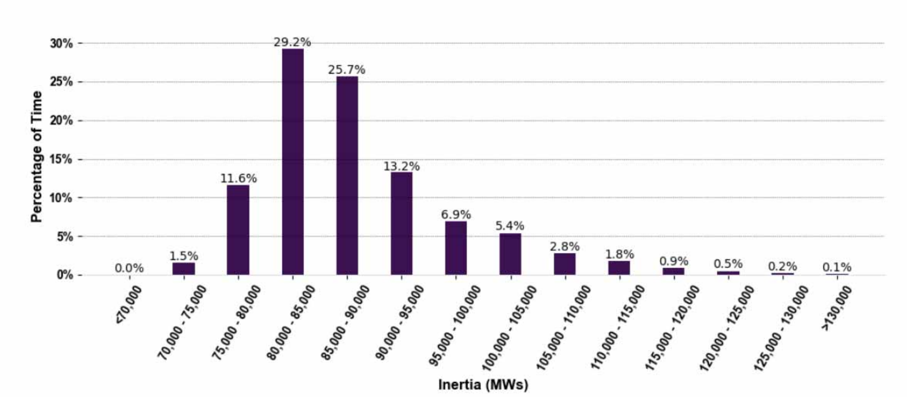
54 Goldwind, submission to the *Efficient provision of inertia* consultation paper, p 5; Tilt Renewables, submission to the *Efficient provision of inertia* consultation paper, p 5.

As outlined above, the current inertia framework takes a reactive approach to inertia needs, limiting procurement to sub-networks that are at risk of separation from the rest of the NEM, with the aim of limiting over-procurement.[55] However, this framework:

- does not recognise that even when intact, the NEM has minimum inertia requirements during interconnected operation to manage system RoCoF, transitory stability and oscillations. Inertia is a global service. As such, restricting inertia solely in regions at risk of islanding could compromise the long-term security of the NEM.
- results in unbalanced procurement which distributes costs unevenly and ultimately may mean some regions of the NEM under-invest in inertia over time while others bear a disproportionate burden.

To date and in the immediate future (see Figure 3.5 below), the mainland NEM has generally had sufficient inertia when intact to maintain security.[56] However, mainland inertia will decline as synchronous generators retire and this may threaten security in interconnected operations.[57] This may occur faster than expected if synchronous generator retirements occur quicker than expected.

**Figure 3.5: Distribution of mainland inertia in Q1 2023**




Source: AEMO, Frequency and Time Error Monitoring — Quarter 1 2023, May 2023, p 19.

To rectify these drawbacks, the Commission proposes to require TNSPs to make inertia available to meet a minimum floor for interconnected operation in the mainland NEM, as explained further below.[58] This would establish an enduring framework that ensures long-term security needs are met, even during periods of 100% IBR penetration.

55 AEMO, *Managing the rate of power system frequency* final determination, 27 June 2017, p 22.
56 AEMO, Advice for the Reliability Panel's review of the frequency operating standard, December 2022, p 40.
57 AEMO, Advice for the Reliability Panel's review of the frequency operating standard, December 2022, p 40.
58 As Tasmania is connected to the mainland through the Basslink undersea DC cable, the inertia floor would not apply.

### 3.3.1 AEMO would set an inertia floor for the mainland NEM to maintain security during interconnected operation

AEMO would forecast inertia floor requirements for the mainland NEM (that is, across all regions except Tasmania) over 10 years, to align with the timeframes for the system strength framework (see section 3.4). As Tasmania is connected to the mainland through the Basslink undersea DC cable, it is subject to different frequency operating standards to the mainland and mostly operates as a synchronous island. Therefore, the minimum mainland NEM inertia floor would not apply. Instead, TasNetworks would continue to be required to meet the secure operating level of inertia in any sub-networks at risk of islanding.

In setting the inertia floor, AEMO would have flexibility but would need to consider principles aimed at ensuring that sufficient inertia is available during interconnected operation. AEMO would consider:[59]

- the level of inertia required on the mainland during interconnected operation to meet the RoCoF limit for credible contingency events in the FOS
- the level of inertia required to maintain security without relying on market interventions
- any other matters that AEMO reasonably considers to be relevant in making its assessment and outlined in the inertia methodology.

In setting the inertia floor, the rules would require AEMO to consider the Reliability Panel's rate of change of frequency (RoCoF) standard for credible contingency events in the FOS.[60] This standard encapsulates system needs during normal operation and the ride-through capabilities of connected plant. Linking the setting of the inertia floor to the FOS ensures that system inertia needs are independently and regularly reassessed by the Reliability Panel, protecting consumers against potentially unjustifiable ancillary service costs.

### 3.3.2 AEMO would allocate proportions of the floor across the NEM to promote balanced procurement

AEMO would be required to allocate the inertia floor among mainland inertia sub-networks in a way that considers both balanced procurement and any regional or sub-regional inertia needs critical to maintaining system security, such as transient stability after small or large disturbances.[61] In determining the distribution AEMO would consider:[62]

- a balanced distribution of inertia throughout the mainland NEM
- inertia needs in each sub-network to maintain system security
- any inter-regional inertia needs
- any other matters that AEMO reasonably considers to be relevant in making its assessment and outlined in its inertia methodology.

59 Proposed draft rule, clauses 5.20.4(d1) and 5.20B.2(b).

60 The revised Frequency operating standard (which will take effect from 9 October 2023) introduced a new requirement for allowable RoCoF following credible and non-credible contingency events. Following a credible contingency event, mainland RoCoF must not be greater than ±1Hz/s (measured over any 500ms period).

61 The spatial distribution of inertia affects the maximum time (or critical fault clearing time) required for protection systems to avoid rotor angle or transient instability after a disturbance. For example, two similar regions with the same total inertia volumes but different inertial distributions can have significantly different critical fault clearing times, which could cause security issues.

62 Proposed draft rule, clause 5.20B.2(b).

AEMO would not be required to consider costs when setting the floor. This is because:

- The security benefits of a wide distribution of inertia would likely outweigh any short-term economic efficiencies because the long-term security benefits of distributing inertia effectively will reduce the risk of costly procurement in the future. While AEMO may be capable of allocating the inertia floor across the NEM to minimise the costs of procurement in the short-term, the security benefits of a wide distribution of inertia would likely outweigh any short-term cost savings if security problems are dealt with proactively, rather than reactively as they materialise.
- Given the expected investment in system strength across the NEM, the Commission considers that any incremental costs to meet the mainland NEM inertia floor would likely be insignificant. In addition, the Commission considers that TNSPs are better placed to assess the most efficient allocation of resources to meet the combined inertia and system strength needs.

### 3.3.3 The inertia floor would complement the existing shortfall framework

Inertia sub-networks may still be at risk of separation and therefore require higher levels of local inertia to maintain system security when operating as an island. As such, the inertia floor would complement the existing shortfall arrangements.

AEMO would continue to assess whether there are any inertia shortfalls in sub-networks as it does under the current framework. If AEMO determines that there is a shortfall in a sub-network, TNSPs would be required to meet the floor amount and make any further inertia available to meet the shortfall amount.

TNSPs would be obligated to make this level of inertia continuously available, three years into the future**.** This mirrors the current system strength obligations.

The obligation to make inertia network services available to meet the inertia floor would be a regulatory obligation or requirement imposed on the relevant TNSP in connection with the provision of prescribed transmission services.[63] The costs incurred by the TNSP would be recovered through the existing cost recovery arrangements.

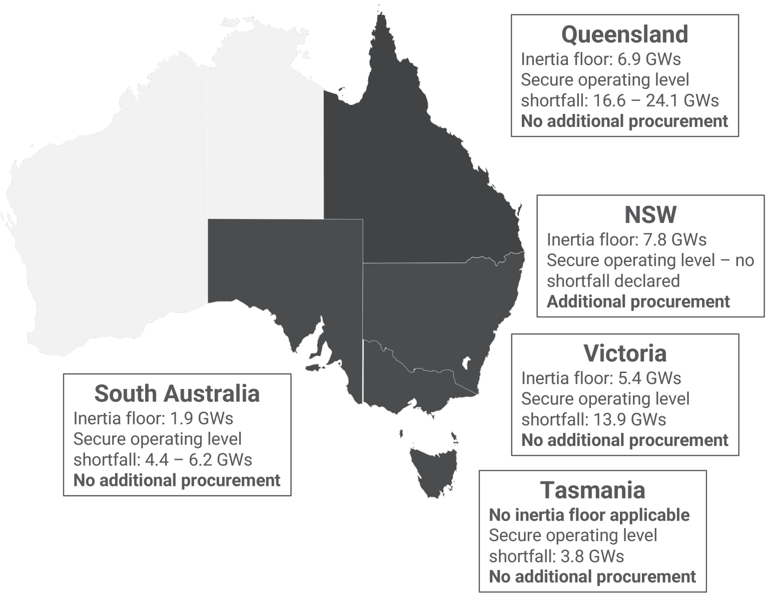
### 3.3.4 The inertia floor would promote balanced and proactive inertia procurement while mitigating risks of over-procurement

An illustrative example of how the new inertia floor could interact with the existing framework is provided in Figure 3.6 below.[64]

63 Proposed draft rule, clause 5.20B.4(a1).

64 The illustrative example assumes a mainland inertia floor for interconnected operation of 22GW.s with proportions of the floor allocated based on ISP generation capacity size. AEMO's implementation of the proposed inertia floor could operate differently in practice.

**Figure 3.6: How the new minimum inertia floor could operate**




Source: AEMC

The example shows that the introduction of a mainland inertia floor would likely only result in increased procurement in regions without existing shortfalls (currently NSW). Such an approach:

- would provide for more balanced inertia procurement, with better distributed cost allocation
- could result in a recalculation of minimum inertia levels in regions at risk of islanding. By considering inertia available in adjacent regions, current and future shortfalls could be reduced.[65]

## QUESTION 1: INTRODUCING AN INERTIA FLOOR FOR THE MAINLAND NEM FOR INTERCONNECTED OPERATION

Do stakeholders support the Commission's proposal to introduce an inertia floor for the mainland NEM?

Do stakeholders consider that the allocation of proportions of the floor across the NEM would promote balanced and proactive procurement?

65 AEMO, 2022 Inertia Report, December 2022, p22. Based on declining inertia levels projected for both New South Wales and Queensland, and historical islanding events between New South Wales and Victoria which led to New South Wales and Queensland islanding together, AEMO has assessed the inertia levels for a combined island of New South Wales and Queensland and accounted for these in the inertia requirements for each inertia sub-network.

## 3.4 Aligning inertia and system strength procurement timeframes would allow TNSPs to more efficiently coordinate investment

The Commission proposes to align the procurement timeframes for system strength and inertia. Under the revised arrangements:[66]

- AEMO would be required to project inertia needs for all sub-networks over 10-years, including the minimum inertia floor for interconnected operation and the secure operating level.
- TNSPs would be required to ensure sufficient inertia is continuously available to meet the projection, for the year that is three years into the future (see Figure 3.7).

This would better support system security needs as thermal generators retire, by projecting inertia needs over a longer timeframe, and improve efficiency and lower costs for consumers by allowing TNSPs to better coordinate system strength and inertia investment over the same timeframes.

**Figure 3.7: The inertia requirements that would bind each year to drive TNSP procurement**

| Year | | 2023/4 | 2024/5 | 2025/6 | 2026/7 | 2027/8 | 2028/9 | 2029/0 | 2030/1 | 2031/2 | 2032/3 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Binding sub-network inertia needs (MWs) | Minimum inertia floor allocation | N/A | N/A | N/A | 3,000 | 3,000 | 3,500 | 3,500 | 3,000 | 3,000 | 3,000 |
| | Secure operating level | N/A | N/A | N/A | 6,500 | 6,750 | 7,500 | 7,750 | 8,000 | 8,250 | 8,500 |
| 2023 inertia report forecasts | Minimum inertia floor allocation | 2,500 | 2,750 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 |
| | Secure operating level | 5,750 | 6,000 | 6,250 | 6,500 | 6,750 | 7,000 | 7,250 | 7,500 | 7,750 | 8,000 |
| 2024 inertia report forecasts | Minimum inertia floor allocation | | 2,750 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 | 3,000 |
| | Secure operating level | | 6,000 | 6,250 | 6,500 | 6,750 | 7,000 | 7,250 | 7,500 | 7,750 | 8,000 |
| 2025 inertia report forecasts | Minimum inertia floor allocation | | | 3,000 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 |
| | Secure operating level | | | 6,250 | 7,500 | 7,500 | 7,500 | 7,750 | 8,000 | 8,250 | 8,500 |
| 2026 inertia report forecasts | Minimum inertia floor allocation | | | | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 |
| | Secure operating level | | | | 7,500 | 7,500 | 7,500 | 7,750 | 8,000 | 8,250 | 8,500 |
| 2027 inertia report forecasts | Minimum inertia floor allocation | | | | | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 | 3,500 |
| | Secure operating level | | | | | 7,500 | 7,500 | 7,750 | 8,000 | 8,250 | 8,500 |

Unexpected changes of inertia needs does not change TNSP procurement until the compliance year

Source: AEMC

Note: Forecast inertia requirements are shown in generic units for illustrative purposes only.

Note: Each year AEMO would publish a forecast of inertia requirements over a 10-year horizon. The above figure cuts off at 2032-33 for illustrative purposes only.

The Commission recognises that — as illustrated in Figure 3.7 — these revised timeframes could create a gap where shortfalls prior to the 3-year compliance period cannot be addressed. The current inertia shortfall framework allows AEMO to declare inertia shortfalls starting 12 months from the publication of the annual inertia report. Under the revised arrangements AEMO could not trigger TNSP inertia procurement within the 12 – 36 month period before TNSPs compliance is assessed.

Unexpected shortfalls could result from:

- the sudden retirement or failure of a synchronous generator
- the failure of a piece of network equipment
- other unforeseen circumstances.

To address unexpected needs arising, the Commission is proposing minor amendments to the NSCAS frameworks that would allow for procurement of system strength and inertia to meet

66 Proposed draft rule, clauses 5.20B.2(b) and 5.20B.4.

minimum system security requirements that eventuate within the 12 – 36 month period. Further details on the proposed changes to NSCAS are in section 3.6.

> QUESTION 2: ALIGNMENT OF THE INERTIA AND SYSTEM STRENGTH PROCUREMENT TIMEFRAMES
>
> Do stakeholders support the Commission's proposal to require AEMO to project inertia needs for all sub-networks every 10 years?
>
> Do stakeholders support requiring TNSPs to ensure that sufficient inertia is continuously available to meet the projection three years into the future, to align with the system strength framework?

## 3.5 Enabling TNSP procurement of synthetic inertia to meet the minimum threshold level would promote system security and economic efficiency

The Commission proposes to widen the eligibility of units capable of meeting the minimum threshold level of inertia beyond synchronous sources.[67] Under the proposed changes:[68]

- TNSPs would be able to procure synthetic inertia to meet the minimum threshold level — subject to AEMO approval
- AEMO would be required to consult on and publish a detailed specification of the required capabilities of synchronous and synthetic inertia to gain approval.

Having clear and transparent requirements for providing synthetic inertia would help original equipment manufacturers (OEMs) and market participants better understand the expected technical capabilities of their equipment to get AEMO's approval. It would also provide clear investment signals of what is required, and encourage providers to invest in such technologies that would do so.

This change could also increase investment in new zero-carbon technologies by providing long-term investment signals to market participants to justify adopting grid-forming inverters.

> QUESTION 3: WIDENING THE ELIGIBILITY OF UNITS CAPABLE OF PROVIDING INERTIA
>
> Do stakeholders agree with the Commission's proposal for TNSPs to be able to procure synthetic inertia to meet the minimum threshold level?

67 The inertia framework defined the minimum requirement as two separate levels: the minimum threshold of inertia which is the minimum level of inertia to operate in a satisfactory operating state when islanded; the secure operating level of inertia which is the minimum level of inertia to operate the sub-network in a secure operating state when islanded.

68 Proposed draft rule, clause 5.20B.4A.

Do stakeholders agree with the requirement for AEMO to consult on and publish a specification of synchronous and synthetic inertia?

## 3.6 The Commission proposes to remove the exclusion on procuring inertia and system strength under the NSCAS framework

Currently, there is no backstop procurement mechanism (other than directions) to procure inertia and system strength services where a shortfall emerges prior to the three-year compliance window. To fill this potential gap where a shortfall emerges or materialises earlier than originally forecast, the Commission proposes to allow inertia and system strength services to be procured through the NSCAS framework.

The proposed new timeframes for inertia, as outlined in section 3.4, are more forward-looking and would align the framework with the existing planning framework for system strength. However, when a shortfall materialises earlier than forecast, or there are unexpected delays with the longer-term solution, there is no procurement mechanism other than directions to procure these services.

The Commission proposes to address these gaps by removing the current exclusion of inertia and system strength from the definition of NSCAS.[69] The proposed arrangements are outlined in detail below.

The Commission considers NSCAS is the most appropriate framework to procure these services because it aligns with the objective of NSCAS. NSCAS requirements represent a gap between the level of services that have been identified by AEMO and those that have been identified by the TNSP. This is referred to as the NSCAS gap. The Commission considers that this technical oversight provided by AEMO under the NSCAS framework aligns with the purpose of this change. Further, the definition of NSCAS is also broad enough to include these services, if the exclusion was removed.[70]

These services were previously removed from the NSCAS framework to allow their respective frameworks to be the primary tool of procurement and because the shortfalls, at the time, applied after 12 months which precluded the 3-year compliance gap.

The inertia and system strength frameworks would remain the primary mechanism for the procurement of these services. The NSCAS framework would only be used as a backstop mechanism where more flexible procurement is required to meet a gap that was not originally forecast.

69 Proposed draft rule, chapter 11, definition of 'NSCAS'.

70 NSCAS is defined as *a service, (excluding an inertia network service or system strength service) with the capability to control the active or reactive power flow into or out of a transmission network to address an NSCAS need.* See chapter 10 of the NER.

In addition, since the decision to exclude inertia and system strength from the NSCAS framework, the compliance date to meet the shortfalls for system strength has been extended to three years.[71] We are proposing to align the forecasts of inertia with system strength, as discussed in section 3.4, which would result in a three-year compliance date. The history of why inertia and system strength were removed from the NSCAS framework is discussed more in section 3.6.1; however, we consider that these reasons no longer apply as also explained in section 3.6.1.

To support the timely and flexible procurement of these services under the NSCAS framework, the Commission is also proposing to remove the requirement for a RIT-T process for the relevant transmission investment if AEMO requires the inertia network and/or system strength services to be provided less than 18 months after the NSCAS gap is declared. This is discussed further below.

> QUESTION 4: REMOVING THE EXCLUSION ON INERTIA AND SYSTEM STRENGTH IN THE NSCAS FRAMEWORK
>
> Do stakeholders agree with the Commission's proposed approach to remove the current exclusion on inertia and system strength in the NSCAS framework?

**Declaring an NSCAS gap for inertia and system strength and procurement responsibility**

As per the proposed NSCAS framework:[72]

- AEMO would declare an NSCAS gap for inertia or system strength (only if the gap will emerge within near-term timeframe and it cannot be addressed by the primary frameworks).
- TNSPs would procure to meet the NSCAS gap relating to either an inertia network service and/or minimum system strength.
- If AEMO considers that the NSCAS gap remains unmet, then AEMO may procure an inertia network service and/or system strength and publish details of why it considered the relevant NSCAS gap persists.

The primary frameworks for these services would remain the primary mechanism to procure inertia and system strength. The proposed change would allow these services to be procured through NSCAS only where a gap arises prior to the three-year compliance date.

**System strength and inertia procurement levels**

TNSPs would be required to procure system strength and inertia up to the levels that are required to meet minimum security requirements.[73] This is because the system strength and

71 The *Efficient management of system strength on the power system* extended the compliance to three years for the SSSP to meet the system strength standard specifications. Setting the standard three years in advance was intended to provide investment certainty for the SSSP given the changing nature of forecasts. NER, clause S5.1.14.

72 Proposed draft rule, chapter 10, definition of 'NMAS'.

73 Proposed draft rule, clause 3.11.1(f).

inertia frameworks are the primary tools to incentivise forward-looking procurement of these services, and NSCAS should only be used when minimum security requirements are under threat in the short term. NSCAS would then be used to fill minimum security gaps to reduce reliance on directions.

This means that:

- for system strength — NSCAS gaps could be declared for the minimum secure level — but not for the 'efficient level'.
- for inertia — NSCAS gaps could be declared for the shortfall amount, including the mainland inertia floor.

**Cost recovery arrangements**

The Commission proposes to apply the current NSCAS cost recovery provisions for TNSP procurement to inertia service and system strength procured through the NSCAS framework, so cost recovery for all services procured through the NSCAS framework are consistent.

Under the NSCAS framework, and where a TNSP is the primary procurer, NSCAS costs are recovered from consumers through the TNSPs' regulated transmission charges. This cost recovery provision also applies to the inertia framework.

The cost recovery mechanism for system strength, however, differs from the inertia and NSCAS frameworks. Under the system strength framework, connecting parties can either pay the system strength charge or self-remediate its general system strength impact.[74] We are not proposing to extend the system strength cost-recovery provisions under the NSCAS framework for either service due to its impracticality. The system strength charge is a forward-looking charge designed to incentivise efficient use of the service for the lifetime of the connection. It is not designed for shorter-term procurement of the more immediate needs of the power system. Furthermore, including extra short-term procurement costs would likely reduce investment certainty for connecting projects, as this could cause short-term changes to connection costs.

We consider that the current NSCAS cost recovery provisions for inertia network service and system strength are fit-for-purpose because NSCAS procurement is intended as a more flexible procurement option to complement, rather than replace, the primary frameworks. It is not likely NSCAS procurement for these services will be used frequently enough to warrant an extensive overhaul of cost recovery mechanisms. The Commission is interested in stakeholder feedback on this.

**RIT-T exemptions**

The Commission proposes that TNSPs are not required to apply the RIT-T to potential expenditure to meet an NSCAS gap relating to either an inertia network or system strength service where the time for making those services available is less than 18 months after AEMO declares the gap.[75]

74 NER, clause 5.2A.2(8).

75 Proposed draft rule, clause 5.16.3(a)(11).

The Commission considers that this aligns with the objective of the proposed approach, to allow more flexible, timely and efficient solutions to be procured when an inertia or system strength shortfall is required in the near-term.

Removing the requirement for TNSPs to undertake a RIT-T to assess capital expenditure expands the options available to TNSPs beyond third-party contracting. This would allow for efficient investment options to be considered, particularly where there is a lack of competition in provision of the required services.

This approach also aligns with the current inertia framework and the previous system strength framework. Under these respective frameworks, the Commission determined that TNSPs would not be required to apply the RIT-T to propose expenditure on "inertia network payments" or "system strength service payments" or to network investment undertaken where:

- the proposed expenditure is to make inertia network services available in relation to an inertia shortfall and the time required for these services is less than 18 months after the notice is given by AEMO[76]
- a fault level shortfall is declared in a region, where prior to the declaration the TNSP is not under an obligation to provide system strength services and where the time for making the system strength services available is less than 18 months after the notice is given by AEMO.[77]

### QUESTION 5: RIT-T EXEMPTION

Do stakeholders think should a RIT-T exemption should apply to inertia and system strength services where a shortfall arises within 18 months?

### 3.6.1 The proposed changes target issues and opportunities in the current NSCAS framework

The Final Determination for *Efficient management of system strength on the power system* extended the compliance to three years for the SSSP, under the system strength framework, to meet the system strength standard specifications. Setting the standard to three years in advance was intended to provide investment certainty for the SSSP given the changing nature of forecasts. Three years was determined to be the shortest period possible to enable SSSPs to appropriately consider all potential solutions for providing the services to meet the system strength standard.

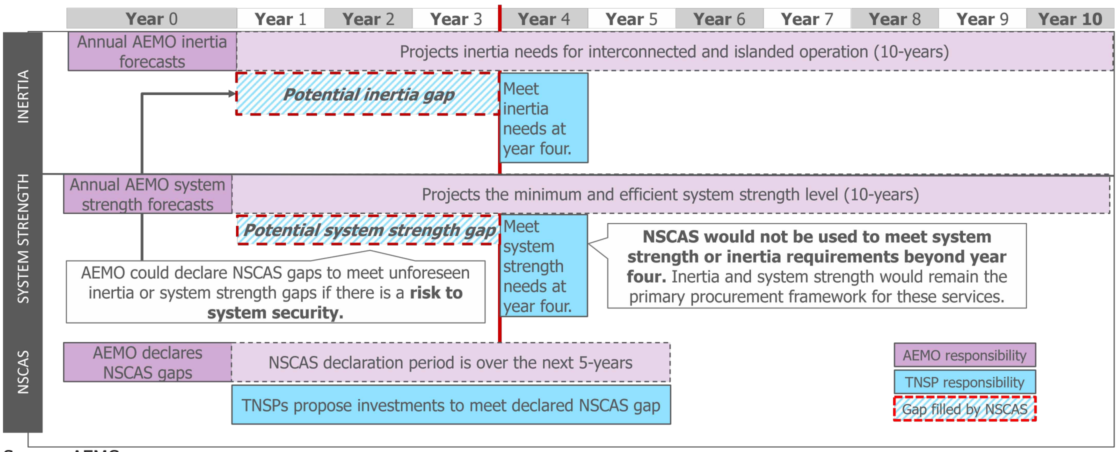
As discussed in section 3.4, the Commission is proposing to align the procurement timeframes for inertia with the current system strength framework. Under the revised arrangements AEMO would be required to project inertia needs for all sub-networks over 10 years with TNSPs bearing responsibility to meet the projections based on the three-year forecast.

76 NER, clause 5.16.3(10)(ii).

77 NER, clause 11.143.16(a).

In order to minimise a gap in system strength or inertia procurement arising before the three-year compliance period, and to give AEMO a tool other than directions, the proposed changes would provide a framework for procurement in this three year period. This would allow TNSPs to procure for an inertia network service and system strength, allowing TNSPs to retain the ability to effectively plan for the most appropriate longer-term solution.

**Figure 3.8: Proposed procurement timelines: inertia, system strength and NSCAS**




Source: AEMC

## 3.6.2 History of why an inertia network service and system strength were previously excluded from the NSCAS framework

Under the current inertia shortfalls framework, AEMO must give notice of the date that the TNSP must provide for the availability of an inertia network service, which must not be earlier than 12 months after the date that the notice of the assessment is published, unless an earlier date is agreed with the TNSP.[78] This was introduced in 2017 by the *Managing the rate of change of power system frequency* rule change.

This aligned with the 2017 Final Determination for *Managing power system fault levels* which similarly gave SSSPs 12 months after the notice of assessment of a shortfall to ensure the availability of system strength services.[79]

The system strength framework was updated in 2021, under the *Efficient management of system strength* rule change*,* which extended the compliance date for SSSPs to make system strength services available to three years.[80] As outlined above, three years was considered the appropriate balance between the need to meet the shortfall, and the time required to determine and implement the most appropriate long-term solution.

The Commission also decided to continue the exclusion of system strength from the NSCAS framework because of concerns that dual procurers in the investment timeframe (as AEMO

78 NER, clause 5.20B.3(c).

79 Previous clause 5.20C.2(c)(2) of the NER (removed by *Efficient management of system strength* rule 2021).

80 NER, clause S5.1.14(a).

can act as a procurer of last resort) may have some perverse outcomes.[81] The Commission did not consider that the NSCAS framework was suitable for the evolved system strength framework. The Commission continues to recognise the risks of dual procurers, however, considers that these risks are mitigated through the proposed approach. This is discussed below.

With regard to inertia, the 12-month compliance date remains. However, as discussed in section 3.1, we are proposing to extend this timeframe to three years to align with the updated system strength framework.

### 3.6.3 The Commission considers the risk of dual frameworks and procurers has changed

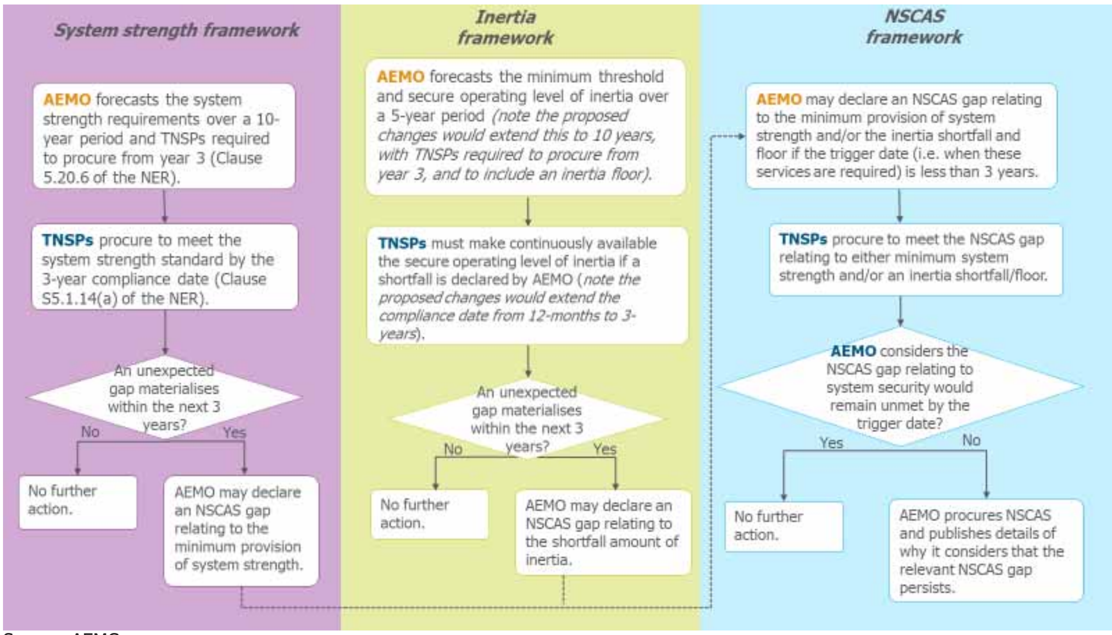
The Commission considers the risks of dual procurement frameworks are mitigated by:

1. **The inertia and system strength framework would be the primary procurement framework for system strength services.** TNSPs would continue to procure under the existing system strength framework to meet both the minimum levels of system strength and the system strength standard (the efficient level). The NSCAS framework would only be used to procure up to the minimum level, not the efficient amount. With regard to inertia, TNSPs would still need to meet their inertia requirements under the existing inertia framework. The NSCAS framework would only be used to procure the shortfall amount.
2. **TNSPs would remain the primary procurer for all inertia and system strength services.** TNSPs would remain the primary procurer for inertia and system strength services under the NSCAS framework. AEMO could only intervene if the gap would be unmet. This is similar to existing arrangements, where AEMO can intervene via directions to procure an inertia network service or system strength if a shortfall arises that was not planned for or captured in the planning timeframe.
3. **The NSCAS framework would only be used as a last-resort procurement where a gap arises prior to the three-year compliance date under the system strength framework.** The NSCAS framework is not intended to be a proactive mechanism for the procurement of inertia or system strength. It would only be used in unexpected situations, for example, a delay in longer-term solutions procured through their respective framework, or a gap materialises earlier than expected.

The Commission considers the risks of dual frameworks and procurers are outweighed by the benefits. System strength, at its core, is a service that keeps the grid stable. It is also central to enabling a smooth transition to a generation fleet with increasing IBR. Allowing more flexible procurement of this ESS would result in a more secure power system at a lower cost to consumers, rather than relying on directions.

81 For more information, see https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

**Figure 3.9: Proposed interactions between the system strength, inertia and NSCAS frameworks**




Source: AEMC

## 3.7 The Commission proposes that most changes to the inertia and NSCAS framework would commence on 1 December 2024

### 3.7.1 Procurement of new levels of inertia would commence on 1 December 2027

The Commission proposes that the new arrangements for AEMO to project inertia needs for the following 10 years, including the inertia floor, would begin on 1 December 2024. This would align with the timing of AEMO's current publication of its annual inertia report, and allow close to a year after the final determination is published for AEMO to adjust its forecasting processes.

This would mean that the requirement for TNSPs to procure the required levels of inertia would commence 3 years later, on 1 December 2027. This allows time for TNSPs to adequately consider procurement options and conduct RIT-Ts.

However, TNSPs may be continuing to enter inertia contracts in the meantime under the existing shortfall framework. The Commission considers that ideally, these contracts would be able to enabled by AEMO along with system strength contracts from 2 December 2025, when TNSPs' system strength obligations begin and AEMO's proposed enablement role begins. The Commission intends to include a requirement that from this date, TNSP inertia contracts would need to be enabled by AEMO. Preexisting inertia contracts prior to this date would continue to be enabled under their existing arrangements.

### 3.7.2 Changes to allow synthetic inertia to contribute to the minimum threshold level would commence on 1 December 2024

To maximise the benefit of allowing a wider range of technologies to contribute to providing inertia during the energy transition as synchronous generation declines, the ability for synthetic inertia to meet the minimum threshold level would commence on 1 December 2024. This gives AEMO time to publish a specification of the capabilities of synchronous and synthetic inertia — after which, synthetic inertia sources would be able to seek AEMO approval so that they may provide inertia network services. This would improve the competitiveness of TNSP procurement for existing shortfalls that have yet to be met, providing an effective investment signal for the future.

### 3.7.3 The proposed commencement date for NSCAS aligns with the start of the proposed changes to the inertia framework

The proposed changes to NSCAS would commence upon publication of the final determination, as potential gaps for system strength could already be arising. The Commission intends that procurement of inertia under NSCAS would only begin when the new inertia arrangements begin (from 1 December 2027) as the problem of a potential three-year gap does not exist under the current shortfall framework.

QUESTION 6: COMMENCEMENT ARRANGEMENTS FOR CHANGES TO THE INERTIA FRAMEWORK

Do stakeholders agree with the proposed commencement arrangements?

Are there extra factors that the Commission should consider in transitioning to the new inertia arrangements?

## 3.8 These arrangements would help promote system security and reduce the use of directions

The Commission considers that the proposed changes in this chapter meet its assessment criteria and the NEO.

### 3.8.1 Promote power system security

The proposed mainland inertia floor would promote power system security by directly including mainland security needs in long-term procurement. It would also provide AEMO with a way to set minimum inertia levels in regions that have localised inertia needs that are not directly related to islanding.

The Commission's proposal to require AEMO to project inertia needs for all sub-networks over 10 years would also better support system security. Making the framework more proactive allows long-term inertia needs to be met in the planning timeframe, promoting system security as synchronous generation declines in the NEM.

Widening the eligibility of inertia sources to meet the minimum threshold level would also benefit power system security by allowing a greater range of technologies to provide security services through the energy transition.

Allowing the procurement of an inertia network service and system strength through NSCAS would also promote the security of the power system by addressing short-term security gaps if they arise, in a way that complements the main frameworks.

### 3.8.2 Emission reduction impacts

As noted in section 1.5 we will use an emissions reduction criterion as part of the assessment framework for this rule change when the change to the NEO becomes law, and we are starting to consider how we would apply this criterion.

The Commission's proposed expansion to allow synthetic inertia to meet minimum threshold levels would also promote emissions reductions as it would allow for a broader range of technologies to be considered in meeting security needs, rather than relying on synchronous plant.

### 3.8.3 Appropriate incentives and risk allocation

The proposed approach allocates incentives, responsibilities and risk to those who are best able to manage them. AEMO has overall responsibility for maintaining power system security and would therefore be responsible for declaring inertia needs and NSCAS gaps TNSPs would need to address these needs in line with their responsibilities for planning, designing, operating and maintaining their transmission network in line with the system security standards.[82]

The introduction of an inertia floor for interconnected operation would provide appropriate incentives and risk allocation by making it easier for TNSPs to consider the inertia benefits of any system strength investment in sub-networks not at risk of islanding, increasing economic efficiency and lowering costs for consumers. Forecasting inertia needs over a 10-year period would also complement appropriate incentives by providing a long-term investment signal for inertia that reflects current and future inertia requirements during interconnected operation. Additionally, the Commission's proposals would also allocate costs across the mainland NEM more equitably by distributing inertia procurement according to the inertia floors set for each region.

### 3.8.4 Transparency, predictability and simplicity

To ensure that stakeholders can understand how AEMO intends to set and allocate the mainland inertia floor, AEMO would include any factors and processes it considers relevant in its *inertia requirements methodology.* It would also continue to report on inertia sub-networks and shortfalls through its yearly inertia report. Together, these reporting requirements would ensure that stakeholders understand how AEMO would forecast and allocate inertia needs, providing greater investment certainty.

82 NER, clause 4.3.4(g).

In widening the eligibility of units capable of providing inertia, the Commission considers that its proposal for AEMO to be required to consult and publish a specification of the capabilities of synchronous and synthetic inertia would benefit stakeholders. Clear and transparent requirements for providing inertia help OEMs and market participants better understand the expected technical capabilities of their equipment to get AEMO's approval. It would also provide clear investment signals of what is required, and encourage providers to invest in such technologies that would do so.

The proposed NSCAS solution is flexible and can adapt to the needs of the power system. It provides flexibility to TNSPs to procure these services in unexpected situations, such as a delay in longer-term solutions (for example, network build), a gap materialises faster than expected or an incumbent coal generator retires earlier than planned. It is also a more transparent solution than directions as AEMO would be required to declare an NSCAS gap in the NSCAS annual report. This would outline what services are required and when. If AEMO considers that gap would remain unmet, AEMO would then be required to publish details of why it considers that the relevant NSCAS gap persists prior to procuring NSCAS.

### 3.8.5 Technology neutrality

The proposed approaches to inertia and NSCAS are designed to be technology neutral. Widening the eligibility of inertia to units capable of providing inertial responses (subject to AEMO's approval) would improve technology neutrality and likely increase competition, resulting in lower costs for consumers. The Commission considers this is particularly important as understanding develops on how new technologies can support system security.

### 3.8.6 Flexibility and consistency with broader reform

Aligning the inertia framework with the new system strength framework would provide the NEM with a flexible and consistent set of approaches to planning and procuring security services during the energy transition. It is also consistent with the overall aim of reducing market intervention as the inertia framework would be more proactive, ensuring that foreseeable security needs are addressed and efficiently met.

By removing the exclusion on inertia and system strength services in NSCAS, it also contributes to the aim of reducing market intervention. These services would likely be procured more efficiently than if AEMO had to rely on directions.

### 3.8.7 Implementation cost and complexity

By building on existing frameworks, the Commission has aimed to keep implementation cost and complexity low. There may be some initial complexity in determining the inertia floor and allocating it among NEM regions, but the Commission considers that this complexity would reduce once methods are in place to do this. AEMO's inertia specification would likely draw on existing expertise, with any potential new work limited to specifying synthetic inertia, which is important for technology neutrality and to support the transition. Otherwise, the Commission considers that the proposed changes to the inertia and NSCAS frameworks are largely building on existing arrangements and would not constitute any significant operational or administrative cost.

The Commission acknowledges that the more proactive approach to inertia procurement may result in increased costs for TNSPs, and therefore consumers, but considers that this would provide net benefits over time in supporting system security more proactively and more equitably distributing inertia procurement across the NEM. Increased costs would likely be mitigated by potentially reducing shortfalls as a result of the new inertia floor, as described in section 3.3.4.

# 4 THE COMMISSION IS PROPOSING A NEW NMAS FRAMEWORK

## BOX 6: KEY POINTS IN THIS CHAPTER

- The Commission proposes to introduce a new NMAS framework for transitional services (the 'transitional services framework'). This would allow AEMO to procure services, in the form of unit configurations, in order to provide system security throughout the transition (and which are likely not captured in existing planning frameworks).
- While the Commission still considers there are efficiency benefits in individually valuing and procuring security services, given the current engineering reality of the system, this is not yet feasible in practice.
- The transitional services framework would therefore allow AEMO to procure security services to meet specific power system requirements e.g. to help contribute and form the unit configurations that are being used to manage the power system. This would allow such resources to be used to maintain power system security, rather than relying on directions.
- This framework would also enable AEMO to prepare for a future without the existing secure configurations and assets that it relies on. Transitional services could be used by AEMO to trial and conduct experimentation on how newer technologies could contribute to system security.
- This would support the power system in transitioning away from synchronous assets via known unit configurations and towards a future NEM with security services provided by diverse technologies.
- AEMO would be required to outline its reasons for procurement prior to using the framework. When in use, AEMO would also need to outline the ongoing costs and services of the transitional services framework each year.
- The framework is designed as transitional, as AEMO's understanding of power system security develops. It is designed with a seven-year review and an expiry date of 10 years. The review would consider how the framework has performed and whether a short extension to the framework is required beyond 10 years. The intent is that the framework is only in use while needed through the transition.

## BOX 7: QUESTIONS FOR STAKEHOLDERS IN THIS CHAPTER

**Need for, and design of, the transitional services framework**

Do stakeholders agree on the need for a transitional services framework?

What are stakeholders' thoughts on the design of the transitional services framework?

**Review and expiry arrangements of the framework**

Do stakeholders agree that a sunset clause is required?

Is a 10-year expiry an appropriate timeframe?

This section covers the Commission's proposal to introduce a new ability for AEMO to procure security services which cannot currently be procured, but are necessary to support the system transition, under a new transitional services framework, including:

- Section 4.2 — The Commission proposes a new NMAS framework to meet security services that are not captured in existing planning frameworks.
- Section 4.2 — Why AEMO needs the ability to procure transitional security services.
- Section 4.3 — How the new NMAS would work as a transitional measure to support the power system transition to a new operating environment.
- Section 4.4 — The framework would be used as a transitional tool, with a set expiry date.
- Section 4.5 — The Commission considers that the transitional services framework aligns with, and promotes, the assessment criteria.

## 4.1 The Commission proposes a new NMAS framework to meet security needs that are not captured in existing planning frameworks

The Commission is proposing to create a new NMAS framework for transitional services. The transitional services framework would complement existing frameworks through the transition. It would do this by allowing AEMO to procure unit configurations that provide system security throughout the transition to 100% renewables and are not able to be procured through existing planning frameworks. For example, it would be used to enable AEMO to enter into contracts with generators that form part of the unit configurations that AEMO is using to manage the system. While AEMO develops its technical and operational understanding of the power system to support the transition and achieve a power system that can be operated at 100% renewables, it may continue to experience issues managing system security throughout this period, so it is important that AEMO has tools to help ensure system security.

AEMO currently uses unit configurations and directions to meet security gaps that arise operationally which cannot be met through other tools. The transitional services framework would enable contracts to be used instead of directions where AEMO has identified a security need that is not specifically an inertia, system strength, or NSCAS gap.

This framework would be designed to adapt as the needs of the power system evolve — it is about delivering the best approach based on current operational realities, while also preparing us to meet the system needs of the future. In addition to procuring for unit configurations based on current power system knowledge, it would also allow AEMO to procure newer technologies for the purpose of testing and experimentation. It would provide

AEMO a framework to trial technologies that may be able to meet security needs in the future, without relying on synchronous assets. The experimental nature of the framework is discussed further in section 4.3.2. Given the focus is on supporting system security needs through the transition, the Commission is proposing the framework as a transitional measure and so it would have a clear expiry date set out in the NER as discussed in section 4.4.3.

Specifically, the transitional services framework would:

- **give AEMO the ability to procure for transitional system services** — the rules would include a dedicated NMAS framework under which AEMO can procure unit configurations to maintain a secure operating system as a transitional measure.
- **allow AEMO to procure security services with the purpose of trialling new system configurations or technologies** — the rules would allow AEMO to procure services for the purpose of performing trials and conducting experimentation in the NEM. This would give AEMO a flexible framework to gain engineering knowledge and confidence on operating the power system with fewer synchronous generators, akin to a sandboxing tool, without necessarily relying on directions.
- **increase transparency on what AEMO needs to maintain system security as the power system transitions to a new operating environment** — the rules would include transparency requirements to allow industry to understand what AEMO needs for system security today, and why and what will be needed longer-term to transition to a new operating environment with fewer synchronous units.
- **place a sunset clause on the framework** — the rules would place a sunset clause that would expire the transitional services framework after 10 years, unless otherwise recommended in the AEMC's seven-year review.
- **require the AEMC to review the framework after seven years —** if this review determined that the framework should be extended, a rule change could be submitted to extend the transitional services framework beyond the 10-year expiry.[83] If the review determined the framework should expire after 10 years, it would automatically do so without a rule change process required.

Notably, the Commission's proposed NMAS framework is designed as a *transitionary* measure. As we move through the transition, system security will likely become more challenging to manage. This will likely only be the case for a transitional period, as we expect that in the future we will likely have sufficient resources and services to provide system security and these will be plentiful. However, during the transition, system security may be scarce as synchronous plant retires, and as we learn about the capabilities of new technology. This is discussed further in Box 8. Given the importance of system security to the integrity of the grid, we consider it necessary to give AEMO an additional tool to manage this as a transitory mechanism.

While AEMO's understanding of the power system is evolving, it is essential that the current arrangements are enhanced to support the most efficient and transparent procurement of these system needs. This framework is designed to adapt as the needs of the power system,

83 Because the AEMC cannot submit a rule change request itself, an external party would need to submit this request.

and our understanding of it, develops in the longer-term. This ensures we are delivering the best approach based on the information that we know today, while also preparing us to meet the system needs of the future.

## 4.2 Why AEMO needs the ability to procure for transitional security services

The energy transition is underway and the NEM is at the leading edge of global thinking about how to run large, interconnected systems with significant amounts of inverter-based resources (IBR).

There is a broad range of technical challenges for operating a grid with high penetrations of variable renewable energy (VRE) and IBR. Some of these technical challenges are better understood than others. As we transition to higher amounts of VRE and fewer synchronous units online, the technical risks of whether new technologies will provide an adequate level of system security increase.

At the moment, AEMO relies on known asset configurations involving synchronous machines to ensure the system is secure. Developing the ability and confidence to meet security needs using new technologies and in new operating conditions (with increased renewables online) will involve a process of progressive testing. In the Engineering Roadmap to 100% Renewables, AEMO outlines how it envisages transitioning to 100% renewables NEM-wide by progressing through 'major hold points'. In this process, the power system's operating limits are expanded through successive milestones, through an iterative process of analysis, testing and assessment, and formalising the new operating envelope.

While the Commission considers there are efficiency benefits in individually valuing and procuring security services, given the current reality of system needs, this is not yet feasible in practice.[84] It is important that progress be made in coming years on these matters. In the interim, AEMO is managing power system security and working towards expanding the operating envelope to 100% renewables, and it is therefore critical it is equipped to do this.

### BOX 8: THE PROPOSED NEW FRAMEWORK IS ADDRESSING A TRANSITIONAL PROBLEM, AS SECURITY SERVICES WILL LIKELY BE ABUNDANT IN THE FUTURE

We consider that scarcities in system security are likely to arise in:

- the **near-term**, as synchronous generators are retiring, reducing the supply of security services. There are not yet appropriate substitutes for the supply –while there are some synchronous condensers installed they are not abundant and grid-forming inverters are not accepted. At this time, we may be able to manage the system securely but will likely have to schedule synchronous generators out of merit to achieve system security.

84 See chapter 1 and AEMO's Engineering Roadmap to 100% Renewables 2022, pp. 16-17.

- the **intermediate-term**, as synchronous generators have retired, and we are starting to get new technologies supplying security services (such as grid-forming inverters and more synchronous condensers), but it is likely that there is not enough yet for system services to be abundant again. During this time, we want to continue to encourage investment and reward those who are operationally providing the services.

However, in the **distant future**, we expect that system security will be once again abundant. This is due to ongoing investment in security-providing technologies as well as AEMO's evolving technical and operational knowledge.

This would be similar to the power system of the **past**, where security services were abundant due to the prevalence of synchronous generators, albeit with security services provided by different technologies.

As AEMO's understanding of the power system evolves, it will have a greater understanding of how to manage system security without synchronous assets, instead obtaining security services from synchronous condensers and grid-forming inverters.

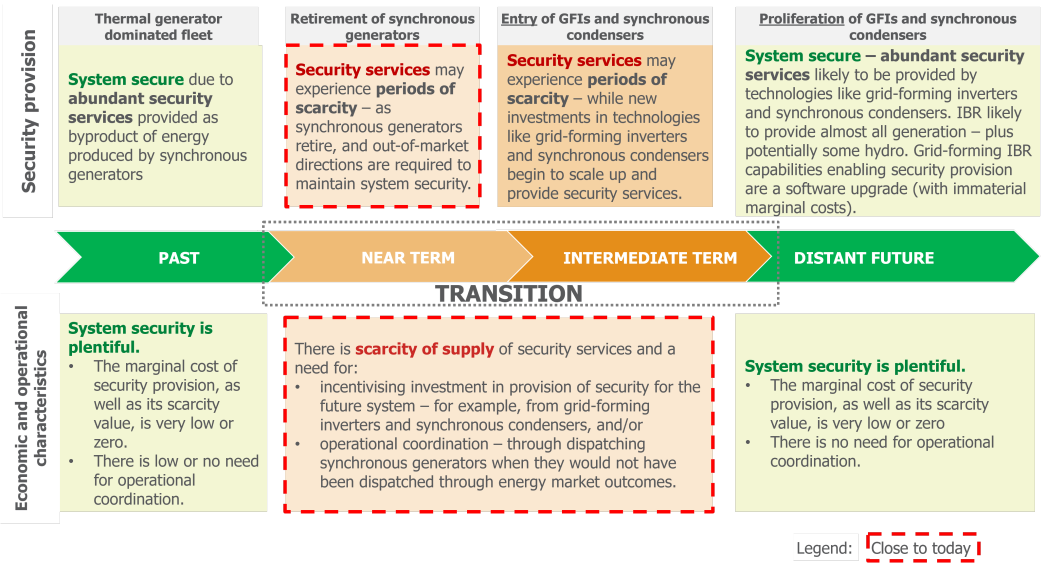
Synchronous condensers can already provide security services including inertia and system strength, and grid-forming inverters are likely to be able to provide many security services in the future. The increasing abundance of these technologies over time is likely to reduce the need for the operational coordination which is currently needed to achieve system configurations. Furthermore, the marginal cost of these technologies providing security services operationally is likely to be low. The Commission understands that synchronous condensers have relatively low ongoing operational costs once the upfront capital investment is made, and grid-forming inverters in future are likely in many cases to only require a software upgrade in order to provide certain security services, again involving low or zero ongoing costs. If this view of the future materialises, there would be very low or zero ongoing costs and potentially also low requirements for operational coordination.

Of course, the capabilities and security demands of new technologies, and therefore the likely future abundance of security services, are still being understood. However, the Commission considers this view of abundant security services as a reasonable view of the distant future of the power system, given the characteristics of synchronous condensers and inverter-based resources.

The transitional services framework is therefore designed to address a temporary need in the near and intermediate-term where security scarcities arise. This is why this proposed framework, unlike the existing security frameworks, has a sunset clause that would expire the framework after 10 years.

While we consider that in the distant future, we will no longer require the framework, we cannot say for certain when the distant future will be. Because of this, the AEMC would review the framework after seven years and could recommend an appropriate extension if there is still a need for transitional services. The review and sunset clause are discussed in more detail in section 4.4.2 and section 4.4.3 respectively.

**Figure 4.1: The transition and its likely impact on security services**




Source: AEMC

While current frameworks already cover most security needs, we recognise there is a range of known unknowns that are not captured in existing long-term planning frameworks. Given that these security requirements do not relate to services that can be currently defined (e.g. inertia or system strength), they are not captured under the existing security frameworks, which results in AEMO directing for them.

For example, in South Australia, AEMO has identified a need for a minimum number of synchronous units online to meet operational requirements.[85] This is to keep the system operating within security parameters and risk tolerances it considers acceptable, while it tests whether it can transition confidently to fewer synchronous units online.

In order to maintain a secure operating envelope, AEMO currently directs required units online (if these units are not already dispatched to be online). There are no alternatives for AEMO to allow it to procure these unit configurations. This issue becomes exacerbated in South Australia given there are so few assets that can meet the unit configurations, which have meant that units increasingly need to be directed.

Because of this, the number of security directions in South Australia has risen significantly since 2016 (although has declined more recently as AEMO becomes more comfortable with less synchronous units online at any one time). Reliance on directions causes a lack of certainty for market participants, wear and tear on equipment, increased risk on the security of the system and is a largely opaque mechanism. See section 4.2.1 for more details.

85 For more information see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/sa-transition-to-fewer-synch-gen-grid-reference.pdf.

AEMO also notes that this is likely a transitional issue for South Australia that will be resolved for normal conditions when Project Energy Connect (PEC) is completed.[86] In its 2022 update on South Australia minimum synchronous generator requirements AEMO notes

> A minimum synchronous generator requirement in SA is not expected to be required under system normal conditions once:
>
> - Project Energy Connect Stage 2 interconnector (PEC) is operational;
> - ElectraNet implement a scheme to effectively manage non-credible loss of PEC or Heywood.[87]

The Commission does not consider that directions should be relied on to maintain system security — they should be a last-resort mechanism but not the primary tool. Therefore, the Commission considers there is a need to put in place frameworks that allow AEMO to procure for these known unit configurations to avoid directions while AEMO develops a better understanding of how to maintain security through the system transition.

The transitional services framework would therefore allow AEMO to procure security services for specific power system needs, for example, to help contribute and form the unit configurations that are being used to manage the power system. These services — that cannot be specifically and individually defined in the same way that inertia and system strength can be — would be procured from assets that make up the unit configurations. This would allow such resources to be used that AEMO knows are needed to maintain power system security, rather than relying on directions.

This new framework would be a simple yet effective approach to manage technical risks while ensuring we are transitioning to a power system with fewer synchronous units online.

While this is to address a transitional need in South Australia, tied to the implementation of PEC, it may arise in other jurisdictions across the NEM. It is therefore important that AEMO can understand how it can manage security without relying on synchronous units to avoid a similar situation to that of South Australia spreading to other regions in the NEM. The transitional services framework would allow AEMO to trial new technologies with the purpose of understanding how it can manage security without relying on synchronous units. AEMO would be able to procure transitional services from a broad range of technologies (known as ‘transitional services providers’) such as inverter-based resources and undertake trials to test the capabilities of these resources.

The proposed NMAS framework is a critical reform that the Commission considers needs to be implemented now to manage system security and prevent situations arising in other parts of the NEM where interventions are frequently used to manage security. It is intended to be a safety net framework, allowing AEMO to procure security services and trial new approaches where no other framework is applicable. We recognise that the framework may not be

86 PEC is an electricity interconnector between South Australia, New South Wales and north-west Victoria. It involves the construction of a new 330 kilovolt (kV) above ground transmission line, with approximately 800MW transfer capacity. The project is expected to be completed in 2024.

87 For more information, see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/sa-synchronous-generator-requirements-stakeholder-update-sep-2022.pdf?la=en.

needed, as our power system knowledge could evolve faster than anticipated. However, the Commission considers it is in the long-term interest of consumers to have this framework available if needed, and potentially not used, than to risk continuing to rely on directions for the foreseeable future.

### 4.2.1 Security directions in South Australia

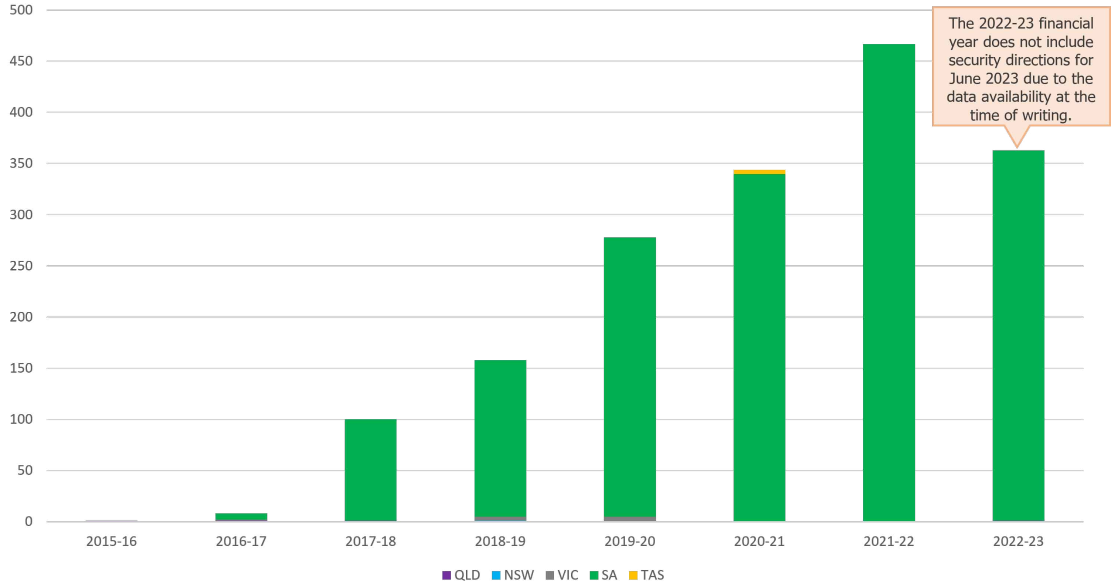
Currently in the NEM, the majority of directions are made by AEMO to synchronous gas-fired generators to ensure that there is adequate system security in South Australia and to make sure there are sufficient synchronous units online in AEMO's unit configurations. This trend started in December 2016, when AEMO announced that at least two large synchronous generating units should be online at all times to maintain system strength in South Australia.

To maintain system security in South Australia, four synchronous condensers were connected and became fully operational on 25 November 2021, following which the system strength limit advice was updated to reduce the minimum number of gas generation units required to ensure power system security from the equivalent of four large units to two under most operating conditions, as well as allowing for an increased nominal limit on non-synchronous generation in the state.

While the four synchronous condensers have addressed the shortfall in system strength in South Australia, AEMO has advised that a minimum number of large synchronous thermal generators are still required online to provide essential system support that may not otherwise be available in the South Australian system.

Over the period of 2016-17 until the present, the number of directions issued in the NEM has increased significantly; see Figure 4.2. The directions issued by AEMO for South Australia are to maintain a minimum number of synchronous machines online to avoid the risk of system instability and supply interruptions following contingency events. Between 1 July 2022 and 27 May 2023, AEMO issued 363 power system directions. Of these, 362 were issued in South Australia. The latter half of 2022, however, showed a decline in the number of directions in South Australia. This could be attributed to the required number of synchronous units online declining, and/or the higher spot price last year resulting in these synchronous units already bidding into the market. Across the period shown below, only 15 security directions were issued in jurisdictions other than South Australia with ten in Victoria, four in Tasmania, three in Queensland, and one in New South Wales.

**Figure 4.2: Directions for security from 2015 to May 2023**




Source: AEMO data via AEMC analysis
Note: The 2022-23 financial year does not include security directions for June 2023 due to the data availability at the time of writing.

Directions, however, are intended to be a last-resort mechanism to manage security. This paper describes the current limitations of the direction's framework in chapter 6. While the proposed changes outlined in chapter 6 would improve the efficiency and transparency of directions, this framework remains unsuitable for the regular use of a security service because it:

**Lacks information on power system needs** — improving transparency on directions would allow for a greater understanding of why AEMO needed to intervene, but it may not go far enough to provide a depth of understanding on power system needs, specifically the transition to fewer synchronous units online.

**Increases the administrative burden** — participants can claim additional compensation under the current (and proposed) compensation framework. There is a significant administrative burden on both market participants and AEMO to submit, review and assess these additional claims.

**Does not provide certainty to participants** — AEMO needs to direct at the latest possible time to intervene. This not only increases the risk of the power system being insecure, but it also means that required directed resources must become available and start-up with short notice. A longer-term contract would allow generators to negotiate startup times in the contracts to provide more certainty on when these services are needed, thus reducing wear and tear.

**Does not support trials of new technologies to support power system security** — the directions framework is designed as a last-resort intervention framework to maintain power system security. Because of the critical nature of this intervention framework, it has a natural bias towards known resources to meet power system needs. A longer-term framework can provide space for testing of advent technologies that may contribute to power system security in the future, while directions remain an essential framework to maintaining the power system security in the operational timeframe.

### 4.2.2 Why a new NMAS framework is a fit-for-purpose solution

The Commission considers developing a new NMAS framework is the best approach to allow for the procurement of these transitional security services. This would align with the operation of the current NMAS frameworks (see Box 9) which allow for the procurement of security services through contracts, outside of spot markets for energy and FCAS.

The transitional services framework would move these services, for example asset configurations, away from being acquired via directions to a more stable and predictable framework that recognises their function in supporting the transition. While other planning frameworks procure for individual services, the transitional services framework would allow procurement of more general power system requirements, for example the online presence of a generator in an asset configuration under specified conditions.

The Commission considers AEMO is best placed to define and procure these transitional services if needed. AEMO is responsible for maintaining and improving power system security across the NEM, and is working towards transitioning the system to be able to operate at 100% renewable penetration. Because these transitional services relate to AEMO's progress towards new ways of keeping the system secure, only AEMO can identify potential providers of these services. Therefore, it is appropriate for AEMO to have procurement responsibility for any transitional services. This would contrast with other security frameworks such as inertia and system strength, where AEMO defines security requirements but TNSPs procure against those requirements.

#### BOX 9: OVERVIEW OF THE CURRENT NMAS FRAMEWORKS

Ancillary services are essential to the management of power system security in the NEM. AEMO acquires both market and non-market ancillary services under the NER:

- Market ancillary services are acquired through central dispatch and the prices are determined using the dispatch algorithm.
- Non-market ancillary services (known as 'NMAS') are acquired under bilateral contracts.

Currently, there are two types of NMAS that AEMO may acquire in its capacity as market and system operator:

- System Restart Ancillary Services (SRAS) and
- Network Support and Control Ancillary Services (NSCAS).

SRAS can help restore electricity supply following a large-scale blackout of part or all of the power system. AEMO must use its reasonable endeavours to acquire sufficient SRAS for each defined electrical sub-network to meet the requirements of the System Restart Standard (SRS) as set by the AEMC's Reliability Panel.

AEMO, in its role as market operator, can also procure NSCAS as a last resort to prevent an adverse impact on power system security and reliability.

### 4.2.3 Why the Commission does not recommend expanding the NSCAS framework

The Commission considered whether these services should be procured under the NSCAS framework, but does not consider they align with the objectives of the NSCAS framework for two reasons:

1. The NSCAS framework is designed to provide AEMO technical oversight of the TNSPs' network planning projections and outcomes.
2. The NSCAS framework gives TNSPs primary responsibility for procurement if an NSCAS gap is declared.

The NSCAS framework allows AEMO to monitor and report on the TNSPs' network planning processes. The NSCAS need definition is, therefore, limited to the transmission network (or substitutes, such as non-network options) to allow TNSPs to build, maintain and plan their network under their regulatory responsibilities, prior to AEMO's review through the NSCAS framework.[88] It is not within the TNSPs' remit under their regulatory responsibilities to plan for power system services that maintain security while transitioning to fewer synchronous units. The Commission did not consider it appropriate to expand the NSCAS need definition's scope to include procurement of a service that is not within the TNSPs planning remit.

The NSCAS framework gives TNSPs primary responsibility for procurement if an NSCAS gap is declared.[89] AEMO is only given powers of 'last resort' if the NSCAS gap remains unmet and if the gap is related to the security or reliability of the NEM.[90] The Commission considers allowing AEMO a greater role in NSCAS procurement would likely lead to confusion amongst procurement roles and would not promote optimal delivery of these services.

## 4.3 How the new NMAS would work as a transitional measure to support the power system transition to a new operating environment

The transitional services framework would build on the existing planning frameworks while recognising the realities of the power system today and current engineering knowledge. While other planning frameworks procure for individual services, the proposed framework

88 AEMO may declare an NSCAS gap if it forecasts an NSCAS need will arise within a planning horizon of at least five years. The NSCAS need must relate to either maintaining the power system security and reliability of the transmission network, or to maintain or increase the power transfer capability of the transmission network to increase market benefits (see NER, chapter 10, definition of *NSCAS need*).

89 NER, clause 3.11.3(a).

90 NER, clause 3.11.3(c)(4).

would allow AEMO to procure security services in the form of known unit configurations that it needs to maintain power system security.

The transitional services framework would also prepare us for a future that moves away from security provision by synchronous assets, by allowing AEMO to trial and conduct experimentation on how newer technologies could contribute to system security. This 'real-world' experience and engineering knowledge is an essential requirement for AEMO to enable the system transition to 100% renewable energy. It would allow AEMO to gain essential engineering knowledge about operating the power system with fewer synchronous generators, akin to a sandboxing tool.

This would be a transitional framework, only being used if needed to support system security until engineering knowledge develops to the point that these transitional services are no longer required. The transitional services framework would sunset after 10 years, with an AEMC review after seven years to consider whether we have enough engineering knowledge at that point such that the framework is no longer needed.

### 4.3.1 AEMO procurement would be limited to security needs

AEMO would only be able to procure services for a security need under the proposed framework. This could include contracts with generators that form part of the unit configurations that AEMO is using to manage the system or for newer technologies that AEMO is trialling to test whether it can manage power system security without synchronous units. This is defined in the objective for the framework that notes:

> The transitional services framework objective is to give AEMO the power to acquire transitional services only where the service cannot be provided by an inertia network service, a system strength service, or any other NMAS. The service is needed to maintain power system security or part of a trial for testing new ways of maintaining power system security, with the aim for AEMO to transition away from reliance on the number of synchronous generating units required to maintain power system security.[91]

The Commission considers that the existing long-term planning frameworks, including inertia, system strength and NSCAS, should continue to be used as the primary framework for the respective security services. This framework would only be able to be used where no other long-term security procurement framework applies. This retains primary responsibility for meeting security requirements with TNSPs, through joint planning arrangements and the system strength, inertia and NSCAS frameworks.

Because the transitional services framework would allow procurement of more general security services rather than individually defined services, AEMO would not technically specify the services that it is providing, but rather it would describe the security need and its reasons for procuring the services for the particular unit configuration.

91 Proposed draft rule, clause 3.11.12.

### 4.3.2 The framework would give AEMO flexibility to adjust procurement to suit security needs over time

As system needs change, AEMO may be able to maintain power system security from newer technologies, such as grid-forming inverters. The proposed framework would also allow AEMO to trial these technologies, or new system configurations. This would be akin to a sandboxing tool. This knowledge is critical to ensuring the success of the energy transition by informing the minimum security requirements going forward and the technical envelope of the future, aligning with AEMO's priority actions in its Engineering Roadmap to 100% Renewables.[92]

The Commission is therefore proposing the transitional services framework would also provide AEMO flexibility to perform trials and conduct experimentation in the NEM to gain essential engineering knowledge about operating the power system with fewer synchronous generators.

To incentivise newer technologies to participate in this framework, it would allow for resources beyond registered participants to enter into bilateral agreements with AEMO. The transitional services framework would allow for a broad range of 'transitional service providers'[93] to support AEMO in increasing their understanding of how newer technologies and resources can maintain system security. We are proposing that AEMO would procure these above services through ancillary service agreements under the transitional services framework.

AEMO would not be obligated to use the framework for this purpose. However, the Commission is supportive of providing AEMO with the necessary tools to ensure it can progress its understanding of power system security to move away from synchronous assets as the transition continues.

### 4.3.3 There would be clear transparency requirements

To mitigate against inefficient or opaque procurement the Commission proposes the transitional services framework would include guardrails. This is distinct from the existing planning frameworks and mirrors the transitional nature of this new framework.

The framework would have transparency measures to allow the broader industry to evolve its understanding of power system security as AEMO's does and to mitigate the risk of opaque procurement. This would include:

*Statement of security needs*

The Commission proposes the transitional services framework would only be used where no other long-term procurement framework applies. To support this, if AEMO proposes to procure through the transitional services framework, it would be first required to publish a statement indicating:

- the security need

92 For more information see https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

93 Clause 3.11.11(a) of the proposed draft rule.

- the expected duration of the security need
- why no other long-term procurement framework applies (for example, why system strength, inertia, NSCAS and other relevant frameworks are not able to solve the need)
- AEMO's intended procurement process. If AEMO proposes to use direct tender, it would need to explain this in the statement and justify its reasoning for direct tendering.

This statement of security needs would need to be linked back to the objective in section 4.3.1.[94]

The Commission considers the statement of security needs would provide industry insight into, and better understanding of, security needs as the system evolves. It would also provide assurance that the framework is only being used where there is not a more specific framework for a service to use.

*Annual report*

AEMO would be required to publish annually a description of the services covered under the framework and include a breakdown of costs for each facility under the ancillary services agreements.[95] This aligns with the current arrangements where AEMO procures services under the NSCAS framework. The cadence of the report also aligns with the broader security frameworks, including NSCAS, inertia and system strength.

The proposed framework would also place an obligation on AEMO to include an overview of the pathway it is undertaking to not require the transitional services in the future. This differs from the existing system security reports, but it reflects the temporary nature of the transitional service framework and its objective to transition to new ways of delivering system security. The Commission considers that a pathway away from using transitional services is particularly important given the rapid need to decarbonise and to manage the system with increasing levels of VRE. The ability to procure services for experimentation under the proposed framework, as discussed in section 4.3.2, may support AEMO in its ability to move away from needing transitional services.

While the statement of security needs addresses the 'why', the annual report will address the 'how' and the 'what' by including the services and costs of the transitional services framework.

### 4.3.4 Competitive or direct procurement would be allowed and the transitional services guideline would set out AEMO's procurement process

It is likely that there would be a shallow market for the procurement of these services, particularly in relation to the need for specific assets that form part of unit configurations while transitioning to fewer synchronous units. For example, in South Australia, there are just two units that AEMO has identified that it needs online to maintain power system security.[96]

94 Clause 3.11.13(a) of the proposed draft rule.

95 Clause 3.11.13(b) of the proposed draft rule.

96 For more information see https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/related-resources/operation-of-davenport-and-robertstown-synchronous-condensers

Because of this, the framework would allow for procurement without a competitive tender and for AEMO to determine the appropriate procurement process.

In determining the appropriate procurement process, AEMO would be required to develop a transitional services guideline that would include:

- factors for how AEMO determines procurement of transitional services (for example, how much competition exists)
- any further relevant procurement requirements of processes (for example, requirements for information, equipment testing, requirements for NSPs or other Registered Participants to identify and resolve issues relating to the provision of the service).

The preparation of the guideline and any major updates would be prepared using the Rules consultation procedure. Participants who are continuously being directed to maintain security would also be permitted to submit offers to AEMO to set up a contract through the transitional services framework instead of being directed. If AEMO does not determine that the participant's services can be procured under the proposed framework, AEMO must outline its reasoning why in the transitional services annual report.

AEMO's obligation to update this guideline using the RCP, as well as its annual reporting obligations and statement of security needs, would ensure accountability in this process. This adds resilience and agility, ensuring that the way we deliver security services evolves as knowledge and technology develop.

### 4.3.5 AEMO would be required to consider whether costs are reasonable

As outlined above, it is likely there will be few eligible providers for the transitional services framework in the near-term as the system transitions to fewer synchronous units online. This may create a risk that AEMO would be unable to negotiate costs as potential providers may have significant leverage.

In light of this, AEMO would be required to consider appropriate remuneration when deciding whether to enter transitional service agreements. The Commission expects AEMO to take into account the following factors when determining appropriate remuneration:

- AEMO's understanding of costs to the provider, profit margins and opportunity costs.
- the cost of using directions for the service — which may indicate a lower bound for reasonable costs.
- the costs of alternative infrastructure that could provide similar functions when AEMO has confirmed its ability to keep the system secure — for example, synchronous condensers (which may indicate an upper bound for a reasonableness test).

We consider this approach balances costs with flexibility, aiming to reduce risks of high costs while also being able to adapt to the particular services being procured.

### 4.3.6 Costs would be recovered in line with NSCAS

The transitional services cost-recovery provisions would be aligned with the current NSCAS provisions. Specifically, this would allow AEMO to recover the costs of transitional services contracts across all market customers, with AEMO having the ability to specify regional beneficiaries, if appropriate.[97]

The Commission considers this cost-recovery mechanism is appropriate as the whole energy market benefits from AEMO operating the power system within secure limits. Further, the ability for AEMO to trial newer technologies also provides system-wide benefits to all market participants.

### 4.3.7 Timeframe for implementation

The Commission considers that AEMO would be able to procure for security services under the new NMAS framework as soon as AEMO has published the procurement guidelines[98] We consider that this reflects that the need for this framework is already occurring, while also recognising that the industry requires transparency of why AEMO is procuring these security services.

### 4.3.8 Compliance

Given that non-compliance with a transitional services framework agreement could introduce system security risks, we propose that a Tier 2 penalty provision be included.[99]

This is the only new penalty introduced in this directions paper as it is also the only new framework proposed. The other policy approaches proposed in this directions paper would make adjustments to existing frameworks that already have equivalent penalties in place.[100] The proposed rule drafting retains these penalties.

> QUESTION 7: DESIGN OF THE TRANSITIONAL SERVICES FRAMEWORK
>
> Do stakeholders agree on the need for a transitional services framework?
>
> What are stakeholders' thoughts on the design of the transitional services framework?

## 4.4 The framework would be used as a transitional tool with a set expiry date

The transitional services framework is proposed as a transitional tool and is not envisioned to be needed once AEMO's understanding of power system security evolves and we return to a position where system security is plentifully provided with new technologies, as discussed in Box 8. Because of this, the Commission proposes the framework would have a sunset period of 10 years; see section 4.4.3 for more details.

97 Proposed draft rule, clause 3.15.6A.

98 Proposed draft rule, clause 11.xxx.1.

99 Proposed draft rule, clause 3.11.11.

100 For example, the system strength framework also includes a tier 2 civil penalty, NER, clause 5.20C.4.

There would also be a review undertaken by the AEMC after seven years. This review would decide whether the framework is required beyond the 10-year point, see section 4.4.2 for more details. The duration of the contracts would also be contained to reflect the transitional nature of the system needs, for further information see section 4.4.1 below.

The transitional services framework would not be used as an explicit tool to provide investment signals. We consider that the existing arrangements, including the current long-term planning frameworks, are sufficient to provide investment signals in the right mix of plant needed to meet system security needs. Instead, it would effectively be another tool to help us maintain system security as we more through the transition.

### 4.4.1 Contract duration would be limited to three years

We propose that the contracts AEMO enters into under the transitional services framework would be for a maximum of three years.[101] The Commission considers that this balances the need for certainty amongst industry, the time in which power system understanding is evolving and the efficiency in multi-year contracts. This approach also aligns with the current IRM and the RERT framework, which provides simplicity and consistency for participants.

### 4.4.2 The AEMC would review the framework after seven years

The Commission would review this new framework by the end of 2030.[102] This would be used to assess whether the transitional services framework is delivering on its objective and determine whether this procurement power is still needed, in light of AEMO's progression of system security understanding and the framework's overall performance. This review would also recommend whether the framework is required beyond the 10-year point.

The Commission considers that the seven-year review timeframe is appropriate to allow sufficient time for the framework to operate so that trends or issues could be identified and AEMO can undertake relevant trials to progress its power system knowledge.

The AEMC could also choose to conduct the review sooner if major issues are identified in the annual reporting processes.

### 4.4.3 The framework would sunset after 10 years unless the AEMC review recommends it be extended

The proposed framework would automatically expire after 10 years.[103] This would not require a rule change process.

However, if the AEMC's seven-year review recommends that the framework should continue beyond 2034, stakeholders could submit a rule change request to extend the framework. The AEMC would then undertake a rule change process considering whether to amend or remove the expiry date. The rule change request would need to be initiated by an external party as the AEMC cannot self-initiate a rule change.

101 Proposed draft rule, 3.11.11(d)(2).

102 Proposed draft rule, clause 11.xxx.2.

103 Proposed draft rule, clause 11.xxx.3.

We consider that the 10-year expiry date is required, as the framework is designed as a transitional measure to address a temporary need. We recognise that at some point, we will not require synchronous generators to provide the system's security needs. However, we cannot say for certain when this date will be, as AEMO's understanding of the power system continues to evolve.

Given this, we consider that some flexibility is required to allow the framework to continue beyond 2034 if required. The seven-year review would provide this flexibility, while the sunset clause reflects the intent of the framework to address a temporary need during the transition.

> QUESTION 8: SUNSET CLAUSE
>
> Do stakeholders agree that a sunset clause is required?
>
> Is a 10-year expiry an appropriate timeframe?

## 4.5 The Commission considers the transitional services framework aligns with, and promotes the assessment criteria

The Commission considers the proposed framework promotes the long-term interests of consumers, as well as the system services assessment criteria. The reasons are summarised below.

### 4.5.1 Promote system security

The proposed framework would promote power system security by providing a long-term planning tool to support AEMO to manage system security through the transition.

Rather than continued use of directions, the framework would be used to more transparently signal system security needs to participants. The bespoke framework would give participants greater certainty on the security services required and providing AEMO more confidence that the right services would be online.

The framework also allows AEMO to improve its understanding of how power system security can be maintained operationally. As we continue the transition to fewer synchronous units online, AEMO would also be able to undertake trials and conduct experimentation on how newer technologies and resources can maintain system security in the new operating environment.

### 4.5.2 Emission reduction impacts

As noted in section 1.5 we will use an emissions reduction criterion as part of the assessment framework for this rule change when the change to the NEO becomes law, and we are starting to consider how we would apply this criterion.

The proposed framework would contribute to emissions reduction by improving AEMO's technical understanding of how new technologies can provide security services, particularly in the context of retiring synchronous generators.

Flexibility in procurement for trials and experimentation means AEMO can get 'real-world' experience in how these technologies can maintain power system security. This would give AEMO and participants the ability to test and learn about the best way to manage power system security, for these transitional services.

The framework would assist AEMO to gain technical understanding of power system security to be able to procure security services from non-synchronous thermal generators as required.

### 4.5.3 Appropriate incentives and risk allocation

The framework would create more appropriate arrangements than directions for those participants whose presence is needed to maintain a secure operating envelope. It would provide those participants with more certainty of when they are required and give AEMO more certainty that those providers will be there when needed.

### 4.5.4 Timely and appropriate mechanism for security

The framework has been designed to be compatible with current arrangements, meaning it would be relatively simple to implement and therefore provide timely support for security. The framework would commence as soon as AEMO publishes its transitional services guideline. Having this framework in place would mean there is less likelihood that other areas of the NEM reach a similar situation to South Australia, where directions are relied on as a primary means to maintain power system security. At the same time, the framework is appropriately transitional, ensuring that costs are only incurred under this framework while they are necessary to maintain security.

The Commission also considers that the framework would assist in AEMO's understanding of power system security, fostering the transition towards the new operating environment. The framework would support AEMO to iteratively improve its understand and management of the system as it transitions, allowing the procurement of transitional needs from new and emerging technology.

### 4.5.5 Transparency, predictability and simplicity

The Commission has designed the proposed transitional services framework to be transparent, predictable and simple. Stakeholders have continually provided feedback throughout this process that these components are important to any change in how security services are valued and procured.

It would provide added transparency on the security needs of the system and how different technologies can meet them. The annual report would provide industry with information on the security services procured and the costs of them.

The transparency arrangements would also improve understanding of system security requirements over time by allowing AEMO to gain more of an understanding of how it can transition to fewer synchronous units online and the performance of new technologies.

### 4.5.6 Technology neutrality

The framework has been designed to be technology neutral, which the Commission considers particularly important as understanding develops on how new technologies can support system security. The Commission considers the technological neutrality of transitional services is important given the need for rapid decarbonisation of the energy system and need to accommodate new technologies.

While scheduled generators are likely to be the majority of framework initially, it has been designed to encourage AEMO to experiment with new entrants and new technologies over-time. The definition of transitional service providers is also broad and flexible, allowing participation by a diverse range of technologies and services, not just those that generate energy.

### 4.5.7 Flexibility and consistency with broader reform

The proposed framework would help facilitate the transition and make management of security more transparent now as it would be flexible and consistent with broader reform.

Given the challenges of the transition that the market is facing, the proposed framework would provide AEMO with the flexibility to incorporate new technical knowledge and expand the number of technologies that are able to be procured through this framework.

The simplicity of the framework and the proposed sunset clause also allows for broader reform to complement, or indeed replace, the framework as required. The proposed framework is not designed or intended to be an enduring solution. It has been designed to provide AEMO the flexibility to manage the system with the knowledge it has today, while increasing its technical understanding to prepare for more long-term solutions.

### 4.5.8 Implementation costs and complexity

The Commission has designed the transitional services framework to be as simple as possible, in line with existing frameworks, which would keep implementation costs and complexity to a minimum. AEMO has not provided an estimate of implementation costs, however, we expect this to be minimal.

The framework has also been designed to retain many of the features of the existing NMAS frameworks, to ensure consistency and simplicity for participants. This includes the cost-recovery provisions of the framework, annual reports, and the procurement process.

# 5 ENABLEMENT OF PLANNING TIMEFRAME SECURITY CONTRACTS

## BOX 10: KEY POINTS IN THIS SECTION

- The Commission proposes that AEMO would enable security contracts that have been procured in the planning timeframe, such as contracts for system strength or inertia, and would also have the option to enable NSCAS or transitional service contracts.
- Placing enablement responsibility on AEMO would align with its overarching responsibility to maintain system security and would allow for the entire pool of contracts NEM-wide to be leveraged to minimise costs for consumers. AEMO also has better visibility than TNSPs over real-time security and IBR participation and would be better placed to enable contracts across regional boundaries to meet the security needs of the NEM.
- AEMO would enable contracts to meet gaps in system security requirements at least cost for consumers and would be guided by various principles that would be specified in the NER. AEMO would also enable system strength contracts to meet the projected level of IBR that is forecast to be dispatched, but only if it results in an overall increase in the level of IBR dispatched in the NEM.
- AEMO would publish an enablement guideline that would outline how AEMO forecasts system security requirements, how it makes and communicates enablement decisions, and the timing of its enablement decisions. AEMO would also be required to publish daily enablement outcomes by reporting on:
  - which contracts have been enabled
  - how frequently have contracts been enabled
  - aggregated enablement costs over the day.
- AEMO would also be required to report at least annually on its enablement processes and provide commentary on any potential improvements that could better promote the long-term interests of consumers.
- In its enablement guidelines, AEMO would specify the information it requires from TNSPs and service providers to ensure that AEMO has the relevant information to effectively enable contracts, such as plant start-up time or minimum enablement levels. AEMO would be able to regularly update these guidelines as it sees fit.
- These arrangements would commence on 2 December 2025, which is the date by which system strength service providers must meet the new system strength standard.

### BOX 11: QUESTIONS FOR STAKEHOLDERS IN THIS CHAPTER

**Placing enablement responsibility on AEMO** (see section 5.3)

- Do stakeholders support the Commission's proposal to place the responsibility of enabling inertia and system strength contracts on AEMO, with an ability to enable NSCAS and transitional services if it is beneficial?
- Are there any issues with split contracting and enablement responsibilities between TNSPs and AEMO that have not been outlined in section 5.3.3?

**Enablement levels to support system security** (see section 5.4.2)

- Do stakeholders support that the Commission's proposed levels for enablement, including the enablement of system strength contracts to levels above the minimum requirement only if it would result in an overall increase in dispatched IBR?

**Enablement principles** (see section 5.4.3)

- Do stakeholders consider the proposed enablement principles to be appropriate and adequate?

**Reporting requirements for enabling system security contracts** (see section 5.4.5)

- Do stakeholders support the Commission's proposal for AEMO to:
  - publish an enablement guideline
  - provide daily information about the type, frequency and cost of enabled contracts
  - publish an annual enablement report?

This section covers the Commission's proposed approach to the enablement (or scheduling) of any planning timeframe contracts for system security that have been entered into, including:

- Section 5.1 — AEMO enablement (or scheduling) of planning timeframe contracts with generators would improve the security of the system, the efficiency of providing system security and the transparency of system security in the NEM
- Section 5.2 — This would address an opportunity to clarify and streamline enablement responsibilities for security services
- Section 5.3 — The Commission considers AEMO is best placed to enable security contracts
- Section 5.4 — AEMO would enable security services to meet system security requirements at least cost for consumers

## 5.1 AEMO enablement (or scheduling) of planning timeframe contracts would improve security, efficiency and transparency of system security in the NEM

The long-term procurement frameworks for system strength, inertia, NSCAS and the proposed transitional services framework allow solutions for certain security needs to be provided through longer-term contracts with parties who are capable of providing these services, or at least part of these services. We refer to such contracts as being 'procured in the planning timeframe'. The proposed changes to these procurement frameworks (described in chapter 3 and chapter 4) aim to provide investment certainty for new investments that provide these needs. They would also seek to provide AEMO (and the market more generally) with greater certainty that it would have sufficient security contracts available to meet security needs on the day.

It would be important to complement these long-term procurement arrangements with clear arrangements for operational 'enablement' — or 'scheduling' — of any such contracts that are entered into. Enablement refers to making decisions in operational timeframes about which participants would be online to meet security requirements, when, and for how long. This section uses the terminology of 'enablement' to mirror the proposed draft rule. Given we are proposing that AEMO 'enables' the contracts, it is also used to include how AEMO communicates with those participants to confirm their enablement. For example, enablement could be for a hydroelectric or thermal unit to be online and synchronised with the power system, or for a battery or other device (such as a synchronous condenser) to be in an operating mode so that it can provide services such as inertia or synthetic inertia.

Enablement arrangements need to cover which party is responsible for making enablement decisions, any rules or guidance for how and when those decisions are made, and how those decisions are communicated and acted upon.

Under the current security frameworks, enablement responsibilities are varied — either sitting with the generator itself, AEMO or TNSPs, depending on the security framework and specific contractual arrangements (see section 5.2):

- for inertia and NSCAS — AEMO can, but is not required to, enable contracts. If AEMO does not enable these contracts, TNSPs need to make enablement arrangements.
- for system strength — AEMO can enable contracts up to the minimum security level, while TNSPs are required to ensure that the efficient level is met, which could include leaving it to the generator itself to make sure it is online at times specified in the contract.

The Commission is proposing to clarify and streamline enablement arrangements to improve security, efficiency and transparency by:

1. **placing enablement responsibility on AEMO** (section 5.3) — AEMO would be responsible for enabling all system strength and inertia contracts (including any system strength and inertia needs that were met by AEMO procuring contracts through NSCAS). AEMO would have the flexibility to enable other NSCAS contracts and any new transitional

service contracts if it considered that this would be beneficial, but it would not be required to enable all of these contracts.

2. **ensuring enablement decisions promote efficiencies, but allowing AEMO appropriate flexibility in how it makes enablement decisions** (section 5.4.4) — contracts would be enabled to meet gaps in minimum system security requirements and also provide system strength to support IBR to reflect the intent of the planning frameworks for system strength and inertia. AEMO would make enablement decisions based on least-cost for consumers. It would be at AEMO's discretion to decide on exact enablement arrangements (for example, the tool or method to be used to make enablement decisions, and timing of issuing enablement instructions), but it would be guided by principles set out in the rules.
3. **ensuring enablement processes and outcomes are transparent** (section 5.4.4) — the rules would introduce transparency requirements on AEMO to ensure that stakeholders are kept informed of its methodology for making enablement decisions and the outcomes of enablement, promoting transparency on how many times such contracts are enabled, the costs of such enablement and also to promote predictability and transparency to the market on outcomes.
4. **placing requirements on TNSPs to provide AEMO with the necessary information to make enablement decisions** (section 5.4.5) — we envisage that TNSPs would require, through contracts, the collection of information from providers to allow them to pass on this information to AEMO. AEMO would outline the information it requires from TNSPs in a guideline.

## 5.2 This would address an opportunity to clarify and streamline enablement responsibilities for security services

As described above, scheduling and enablement responsibilities for the long-term security frameworks fall to either generators themselves, AEMO or TNSPs and differ depending on the different procurement frameworks as well as the individual contractual arrangements within the frameworks.

### 5.2.1 AEMO can currently enable inertia and NSCAS contracts — but is not required to

Under the **inertia** framework, as described in section X, TNSPs procure inertia, and TNSPs can set the enablement arrangements or AEMO can enable the inertia services if the contract provides for this.[104] AEMO can enable services in the following situations:

- where a contingency event that would result in the islanding of an inertia sub-network has been classified as a credible contingency event or defined as a protected event — AEMO can enable inertia services up to the minimum threshold level.
- where an inertia sub-network is islanded — AEMO can enable inertia services up to the secure operating level.[105]

104 NER, clause 4.4.4.
105 NER, clause 4.4.4(a) and (b).

In selecting the inertia network services to be activated, AEMO must use reasonable endeavours to select the services in the order of priority specified by the relevant TNSP.[106]

Similarly, under the **NSCAS** framework, where NSCAS is acquired by TNSPs it can be dispatched (equivalent to enablement) by either the TNSP or AEMO. This arrangement was confirmed by the Commission in the 2012 *Network Support and Control Ancillary Service* rule that concluded that:

> The benefits of the new arrangements include promoting efficient operation of electricity services by allowing NSPs to either dispatch NSCAS they acquire or to allow it to be dispatched by AEMO.[107]

In cases where AEMO procures NSCAS because the TNSP has not been able to, AEMO would be able to dispatch the NSCAS in accordance with contractual arrangements.

Under the current rules AEMO may dispatch NSCAS to:[108]

- maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard
- maintain or increase the power transfer capability of that transmission network to maximise the present value of net economic benefits to all those who produce, consume or transport electricity in the market.

### 5.2.2 TNSPs are currently responsible for ensuring the full amount of system strength is operationally available

The current **system strength** framework was introduced in 2021 and its implementation is currently underway. It will be fully implemented by December 2025. Under the framework, system strength service providers[109] are required to use reasonable endeavours to plan, design, maintain and operate their transmission networks, or make system strength services available to AEMO, to:

- meet the minimum level of system strength (the three phase fault level), and
- achieve stable voltage waveforms for the level and type of IBR projected.[110]

SSSPs can choose to meet these requirements through network investment (such as synchronous condensers) or by entering contracts with providers of system strength services, such as synchronous generators or privately owned synchronous condensers. Some contracted system strength will require enablement decisions close to real-time, — for example, a thermal generator needs to be dispatched in order to provide system strength.[111] AEMO can enable these contracts to maintain the minimum three phase fault level at any

106 NER, clause 4.4.4(c).

107 AEMC, *Network Support and Control Ancillary Services,* final determination, 7 April 2011, p 8.

108 NER, clause 3.11.6.

109 System strength service providers (SSSPs) are a subset of TNSPs and AEMO in Victoria.

110 NER, clause 5.1.14.

111 Some non-network solutions, such as collective inverter retuning, or network solutions such as installation of synchronous condensers, do not require instructions from AEMO or the TNSP to be enabled, and could therefore be used in the operational timeframe to provide system strength services to meet both limbs of the standard.

system strength node but cannot enable them to achieve stable voltage waveforms to support projected IBR.[112]

### 5.2.3 Placing enablement responsibility on one party would improve efficiency

In the system strength rule change, the Commission considered whether AEMO should be allowed to enable contracts to support meet the second limb of the system strength standard (i.e. to support the stable voltage waveform) and achieve net market benefits. While it was noted that SSSPs could include arrangements in the contract itself that incentivise or require generators to self-commit in order to provide system strength to meet the second limb of the standard,[113] the Commission considered that the OSM rule change process should consider how AEMO would enable system strength services contracted under the second limb:[114]

> The draft rule did not specify how AEMO would enable system strength services contracted under the second limb [the efficient level]. This was due to there being ongoing parallel rule change processes that were considering the most efficient and effective ways for operational arrangements for unit commitment and other required services that are essential for power system security. This is continuing through the AEMC's consideration of the Capacity commitment mechanism proposed by Delta Electricity and the Synchronous services market proposed by Hydro Tasmania. [115] [116]

Furthermore, having one party that can leverage the combined pool of security contracts would mean that the lowest-cost contracts can be chosen to meet security requirements at any given time, minimising costs for consumers (see section 5.3.3).

Additionally, having the entire pool of contracts to leverage would improve security outcomes by making all options available to meet security needs and would reduce reliance on market interventions as the system continues to decarbonise.

### 5.2.4 Both rule change requests and the OSM draft determination proposed new approaches to enablement

Both rule change requests and the OSM draft determination proposed approaches to enablement (scheduling) to improve operational efficiency and coordination:

- Hydro Tasmania proposed that participants would bid and be paid for co-optimised real time security services in the same way as for energy and FCAS.[117]

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112 NER, clause 4.4.5.

113 AEMC, System strength final determination, pp 95-96.

114 AEMC, System strength final determination, p 101.

115 AEMC, System strength final determination, p 96.

116 The Commission consolidated the *Capacity commitment mechanism* and *Synchronous services market* rule change projects into the *Operational security mechanism* rule on 2 February 2022.

117 Hydro Tasmania, *Synchronous services markets* rule change request, 14 November 2019

- Delta Electricity proposed a day-ahead, ex-ante commitment market, where participants could be committed to provide security and reliability services for a whole day (for slow-start plant) or specific trading intervals (for faster-start plant).[118]
- The OSM Draft Determination proposed a scheduling mechanism which would iteratively determine system security needs, and procure and schedule for these needs as close to real-time as possible.[119] This design aimed to maximise the net benefits of trade across the energy, FCAS and OSM markets by publishing expected OSM schedules and allowing all markets to iteratively adjust in response.

The proposed approach to enablement in this directions paper (section 5.4) is simpler and more flexible than the previously proposed scheduling mechanism. It would give AEMO flexibility in exactly how to make enablement decisions, while ensuring that costs for consumers are minimised and system security is maintained. Furthermore, it is unlikely to significantly or adversely affect the wholesale energy market as it avoids creating an 'ahead' market and other significant interactions with the wholesale market distort real-time energy price signals.

## 5.3 The Commission considers AEMO is best placed to enable security contracts

The Commission considered whether AEMO or TNSPs should be responsible to enable system security contracts. We consider that it would be preferable for AEMO to enable these contracts. This is because it is better-placed than TNSPs due to its operational security responsibilities and greater ability to coordinate operational security needs.[120]

### 5.3.1 Enablement would need to achieve minimum operational security requirements and host IBR online

The Commission considers that enablement decisions should support the policy intent of the long-term frameworks for managing system security, as far as practical. This means that contracts should be enabled to meet minimum inertia, system strength, NSCAS and any transitional security requirements, as per the respective security goals of each framework.

Enablement should also reflect the intent of the system strength framework, which is to ensure system strength can be available to a level that supports IBR that is projected to connect. The Commission notes that this was not intended to guarantee *dispatch* of IBR in operational timeframes, with this still being guided by the outcomes of NEMDE. However, in general, the Commission considers that system strength contracts should be enabled to support this goal where practical and efficient.

118 Delta Electricity, *Capacity commitment mechanism for operational reserve and other system security services* rule change request, 4 June 2020.

119 AEMC, *Operational security mechanism* draft determination.

120 While generators can self-schedule into the energy market to provide a security service under a contract with TNSPs, for the purposes of this paper, this is considered equivalent to TNSPs being responsible for enabling contracts. This is because, in practice, these generators would self-commit in the energy market according to a predetermined schedule or some other information ahead of real-time that is included in the conditions of the contract with their TNSP.

### 5.3.2 Either AEMO or TNSPs could enable long-term security contracts

The Commission considers that either AEMO or TNSPs could develop systems to enable long-term security contracts to meet these goals in a coordinated manner.

AEMO could develop a tool or system which:

- identifies system security needs close to operational time
- decides which is the lowest-cost set of security contracts to meet these needs, and
- communicates enablement decisions to participants.

One example of this approach could be a simplified version of the previously designed scheduling tool described in the OSM draft determination. In contrast to that design, the current approach would mean that the tool meets security requirements at lowest cost (rather than maximising the net benefits of trade). It would also not conduct operational procurement (instead, it would only enable existing long-term contracts).

TNSPs could take a number of approaches to meet this goal. For example, they could:

- place static obligations on parties as part of the contract to meet security requirements and support projected IBR. Under this approach, a unit would be required to self-commit in the energy market based on a predetermined schedule
- specify triggers for parties to respond to — for example, a unit would be required to self-commit in the energy market based on trigger circumstances in ST PASA
- develop systems to enable units closer to real-time to try and more accurately achieve operational security and support the expected IBR generation on the day.

### 5.3.3 AEMO enablement would align with AEMO's system security responsibilities and facilitate efficient outcomes

One of AEMO's key responsibilities is ensuring operational system security.[121] Having AEMO be responsible for enabling contracts would help to make sure that AEMO has the tools it needs to achieve a secure system. In fact, this responsibility is already reflected in AEMO's current powers to enable security contracts like inertia and system strength if necessary (even though those contracts are between participants and TNSPs).

Placing enablement responsibility on AEMO would also achieve efficiency in a number of ways.

First, AEMO has better visibility than TNSPs over real-time security needs and IBR participation in the market. This is because AEMO is responsible for operating the wholesale market and has responsibility for the integrity of the system. Therefore, AEMO would be better-placed to more precisely determine the number of contracted resources needed online at the time. This would reduce the chances of over- or under- enablement, therefore reducing risks to security (by under-enablement) and costs for consumers (by over-enablement).

121 NER, clause 4.2.1(a), and NEL, clause 49(1)(e).

AEMO also has better visibility of inter-regional security provision than TNSPs. Security services like inertia can be provided across regional boundaries. System strength can also be provided across regional boundaries (even through it is relatively localised) given the development of the grid at its fringes to support renewable energy zones. AEMO is therefore best-placed to determine the NEM-wide lowest cost approach to maintaining security and avoid activating multiple units to meet the same security need. If each TNSP was enabling security contracts for security needs in its own region, then units in different regions could be activated for the same security reason, increasing the chances of inefficient over-procurement and increased costs for consumers.

Another key advantage of this approach is that only one centralised system for enablement would be needed, rather than each TNSP developing its own capabilities and systems, including the need to communicate close to real-time with other TNSPs to determine security needs and which TNSPs' contracts would be enabled to meet those needs.

Finally, this approach is likely to be more consistent and transparent than individual TNSPs each developing systems and approaches for enabling contracts.

AEMO would require resourcing to develop and operate a tool or system for enablement. However, the Commission considers this could be relatively simpler than the previous OSM design and at lower cost. It could also be designed in such a way that it is more flexible.

The Commission also considered that this approach would result in split contracting and enablement responsibility. TNSPs would not be activating their own contracts — but would be incurring activation costs. This could lead to:

- financial risks for TNSPs, if contracts are activated more than originally expected and recovered for. However, this is mitigated by TNSPs' abilities to recover any extra costs through transmission use of system (TUOS) entitlement adjustments.
- a lack of the ability to build in incentives for TNSPs to 'beat' their originally projected costs and lower costs for consumers — analogous to the efficiency benefits sharing scheme (EBSS) / capital efficiency sharing scheme (CESS).[122] However, costs for consumers would be kept down by AEMO activating contracts at lowest cost, avoiding duplicating activation of contracts to meet the same security need, and the increased efficiency from AEMO's ability to more closely reflect security needs on the day.

It is worth noting that under the current inertia and NSCAS frameworks, AEMO already has the ability to enable TNSP-procured contracts. The Commission considers that the split in contracting and enablement does not pose any significant legal risk, and contributes to ensuring efficiency over the operational and planning timeframes (as discussed in section 5.3 and section 5.4).

122 The efficiency benefits sharing scheme (EBSS) is an AER-administered scheme that aims to reward network service providers that improve the efficiency of their operating expenditure and pass on these efficiency gains to consumers. The capital efficiency sharing scheme (CESS) is a similar AER scheme that applies to the capital expenditure, rather than the operational expenditure, of network service providers.

### 5.3.4 TNSP enablement would be less efficient due to lower system visibility and the need to implement multiple systems

In contrast, the Commission considers that although it would be possible for TNSPs to be responsible for operational enablement of security contracts, this approach would introduce security risks and inefficiencies.

This approach could give rise to security risks if TNSPs were responsible for enabling contracts to meet minimum security requirements. This is because there may be disparity between TNSPs' and AEMO's parameters for the level of services required to maintain security in the operational timeframe. AEMO would always need operational oversight of security, and the power to address gaps through tools like directions, even if TNSPs were responsible for enabling security contracts — and this would result in duplication of efforts.

There are also efficiency drawbacks to TNSPs enabling contracts that mirror the advantages of AEMO activating contracts outlined above:

- TNSPs have less visibility of inter-regional flows of system strength and other security services. As such, TNSPs would likely activate more contracts than required to be certain the required level is met in all regions.
- TNSPs cannot activate or enable contracts in adjacent regions. As such, TNSPs would be unable to optimise the activation of all contracts to come to a NEM-wide lowest cost solution.
- All implementation options available to TNSPs would be subject to inefficiencies:
  - If TNSPs relied on a preset pattern of enablement, or a trigger such as ST PASA to indicate when enablement was required, this is likely to under- or over-enable contracts due to forecasting error, sacrificing efficiency and so compromising security or increasing costs for consumers.
  - If all TNSPs enabled contracts close to real-time, in response to system needs and conditions on the day, each would be required to individually develop a tool or system to enable contracts. The duplication of tools throughout the NEM would likely increase costs, potentially compromise transparency and may increase complexity when compared to a single tool.

#### QUESTION 9: PLACING ENABLEMENT RESPONSIBILITY ON AEMO

Do stakeholders support the Commission's proposal to place the responsibility of enabling inertia and system strength contracts on AEMO, with an ability to enable NSCAS and transitional services if it is beneficial?

Are there any issues with split contracting and enablement responsibilities between TNSPs and AEMO that have not been outlined above?

## 5.4 AEMO would enable security services to meet system security requirements at least cost for consumers

To provide guidance on how the contracts are to be scheduled in the operational timeframe, the Commission proposes to include enablement principles and minimum requirements in the rules. [123]

### 5.4.1 Levels of services to be enabled

AEMO would enable security services to levels that meet gaps in minimum security requirements and host projected IBR as described in Table 5.1.[124]

Table 5.1: Levels of security services to be enabled by AEMO

| SECURITY SERVICE OR NEED | CONTRACTS TO BE ENABLED BY AEMO | LEVEL OF THE SECURITY SERVICE TO BE ENABLED |
|---|---|---|
| **System strength** | AEMO would enable all system strength contracts — including any NSCAS contracts for system strength gaps. | Enough **system strength** would be enabled to:<br>• meet the minimum three-phase fault level, which represents minimum security requirements<br>• provide a secure voltage waveform to host the projected dispatched amount of IBR, subject to an IBR principle (see section 5.4.2 for further details). |
| **Inertia** | AEMO would enable all inertia contracts — including any NSCAS contracts for inertia gaps. | Enough **inertia** would be enabled to meet minimum inertia requirements for security — that is, the mainland inertia floor and any inertia needed in an inertia sub-network if it is credibly at risk of separation or islanded. |
| **NSCAS** | It would be at AEMO's discretion whether to include or exclude NSCAS contracts from any enablement tool or | **NSCAS** contracts, if included in overall enablement processes, would be enabled to meet the |

123 Proposed draft rule, clause 4.4A

124 When AEMO 'enables' a contract, it would instruct the unit to either commit in the energy market by bidding at the market floor, by applying a must-run constraint in NEMDE, or through some other means as AEMO sees fit. The proposed draft rule does not specify how AEMO would instruct enabled units to be online for the relevant trading intervals.

| SECURITY SERVICE OR NEED | CONTRACTS TO BE ENABLED BY AEMO | LEVEL OF THE SECURITY SERVICE TO BE ENABLED |
|---|---|---|
| | process (except NSCAS contracts for system strength or inertia, as above).<br><br>NSCAS contracts can address very specific locational needs, which means that it may not make sense to include them in an overall enablement process. | relevant system security requirements (i.e. to meet the declared NSCAS gap). |
| **Transitional services** | It would be at AEMO's discretion whether to include or exclude transitional service contracts from any enablement tool or process.<br><br>Like NSCAS, transitional service contracts would be expected to often address very specific locational needs. | **Transitional service** contracts, if included in overall enablement processes, would be enabled to meet the relevant system security requirements (i.e. to meet the transitional need) |

Importantly, AEMO would only enable contracts where there is a gap between the outcomes of projected dispatch and these specified levels. This maintains the effectiveness of the energy market spot signal. If contracts were to be activated to meet the entire system security need instead, then it is likely that many contracts would often be enabled ahead of time, taking these participants out of the energy spot market, which is not the intent of the security frameworks.

The Commission acknowledges that this approach could result in participants being enabled for security requirements that have flow-on impacts on the energy spot price, which may cause other participants to decommit in response — which could then cause a further security gap that requires further units to be enabled. However, this risk is significantly reduced when compared with the design of the OSM as outlined in our draft determination. In the OSM design, enablement and dispatch outcomes would have been iteratively adjusted based on expected spot market prices and changing OSM rebids to maximise the value of trade across the OSM, energy market and ancillary service markets (see chapter 2). Here, the Commission's proposed enablement principles would mean that although some participants may be displaced, the overall effect on the spot market would be much more minimal due to the static costs of enabling contracts and the fact that enablement is not based on forecast energy or ancillary service prices.[125]

125 The proposed enablement principles also mean that there is significantly less risk of enabling a contract for energy purposes only ahead of real-time, as each contract would be enabled to meet a tangible gap for a particular security service. If there are no security gaps between pre-dispatch and real-time, then no contracts would be enabled, avoiding any energy-only commitments. While the Commission stated in our draft determination that the 'OSM would not schedule security services for the sole purpose of reducing energy costs', this would have been difficult to avoid through a mathematical optimisation engine with an objective function of maximising the value of trade across the energy, FCAS and OSM markets.

The Commission considers that the inefficiency risk of affecting energy market outcomes by enabling contracts for the gap between pre-dispatch and real-time is still preferable to enabling all units up to the required levels. This risk would also be mitigated by the enablement principles that AEMO would aim for efficient outcomes when enabling contracts ahead of time (see section 5.4.3 below).

### 5.4.2 AEMO would schedule system strength to meet the projection of dispatched IBR

System strength is the only service that would be enabled to achieve a goal above minimum security requirements. The intent of the system strength framework is to have enough system strength available to host the level of IBR online that was projected in the planning timeframe. However, the Commission was clear in the *Efficient management of system strength on the power system* final determination that the system strength framework would not provide all IBR with an absolute guarantee of dispatch in real-time, stating that:

> While it is acknowledged that one of the objectives of this final rule is to minimise these system security interventions by AEMO, the Commission considers that it will be inefficient to eliminate them completely. The costs of SSS Providers providing system strength services so that IBR could have unconstrained access will in all likelihood exceed the benefits of the reduced generation costs.[126]

The Commission considers that to implement this policy intent, system strength should be enabled to host the level of IBR online **unless** this would result in dispatch outcomes that would not be practical or that would significantly compromise efficiency. Specifically, the Commission wishes to avoid situations such as where:

- an entire system strength contract is enabled to support a very small amount of IBR dispatch, which would result in inefficiently high costs for consumers. For example, a thermal generator with a 50 MW baseload is enabled to provide a stable voltage waveform for the final 1 MW of a dispatched IBR resource.
- system strength is enabled to support IBR coming online and the result is that this simply displaces an equivalent amount of IBR that would have otherwise been dispatched. For example, 50 MW of system strength is enabled to support 50 MW of IBR, which displaces 100 MW of IBR from being dispatched elsewhere.

Under the Commission's proposed approach, AEMO would:

1. project the level of expected IBR dispatch over a specified enablement period, by considering factors such as:
    a. IBR bids into pre-dispatch
    b. forecasts of projected IBR generation
    c. ST PASA
    d. effect of network constraints
    e. operational demand

126 AEMC, *Efficient management of system strength on the power system* final determination, p 38.

   f. any other factors AEMO reasonably considers relevant.

2. determine the amount of system strength required to ensure a stable voltage waveform to host this projected level of IBR.
3. enable system security contracts to fill any system strength gap over the enablement period at least cost, up to the maximum system strength level projected over the planning timeframe.

To ensure IBR is not simply displaced by system strength bringing different IBR resources online, AEMO would enable contracts **only if:**

- the enablement of system strength contracts results in an overall increase in dispatched IBR
- the total increase in dispatched IBR is greater than the total energy provided by additional system strength contracts.

As well as supporting efficient outcomes, the Commission considers that this principle would help manage costs for consumers by reducing the frequency of situations where system strength contracts are enabled to increase the amount of dispatched IBR without a reduction in the wholesale energy price. Moreover, the Commission considers it is reasonable to incur system strength contract costs where these simply implement the intent of the system strength framework and help incentivise more IBR to be dispatched and come online. Over time, if cheaper IBR is able to be dispatched more often through enablement, then the wholesale energy price is likely to reduce, outweighing the costs of system strength contracts.

### QUESTION 10: ENABLEMENT LEVELS TO SUPPORT SYSTEM SECURITY

Do stakeholders support that the Commission's proposed levels for enablement, including the enablement of system strength contracts to levels above the minimum requirement only if it would result in an overall increase in dispatched IBR?

### 5.4.3 AEMO's enablement decisions would be guided by principles in the Rules

The Commission considers that AEMO should aim to achieve system security at least-cost for consumers, but it should also have some flexibility in how it makes and communicates enablement decisions, so that it can accommodate both system needs and the needs of security service providers. The Commission is therefore proposing a principles-based approach to AEMO's enablement decisions, where AEMO would be required to:[127]

- enable a combination of contracts that meet the required level of the security services at lowest cost
- not enable contracts more than 12 hours ahead of time

127 Proposed draft rule, clause 4.4A.4.

- aim for efficient outcomes when enablement contracts ahead of time — balancing more accurate forecasts closer to real-time with unit commitment constraints
- enable contracts only when energy spot market outcomes are not expected to provide the required level
- only enable contracts to meet security service gap, not always enable for the full amount of the required service
- enable contracts for stable voltage waveforms only where it meets the IBR principle outlined above in section 5.4.2
- aim to — but not be required to — use contracts specifically for their contracted purpose (for example, system strength contracts to meet system strength needs).

These principles aim to achieve both efficiency (lowering costs for consumers) and flexibility for AEMO. They also aim to ensure that contracts are used for their intended purpose, to provide as much contractual certainty as possible that operational costs actually incurred would reflect expectations formed in the planning timeframe. The rules would not preclude AEMO from enabling contracts that incidentally meet other system needs, for example, a system strength contract could be activated which also meets an inertia need. However, AEMO would be required to use reasonable endeavours to use contracts for their intended use.

Under these principles, AEMO could for example make enablement decisions progressively over a 12-hour period, to accommodate individual plant circumstances such as different start-up times. The principles also limit ahead-commitments to 12 hours, which is considered enough time for most plant to come online, and reduces forecast error.

The principles intentionally do not specify a particular tool or process for AEMO to use in making enablement decisions — AEMO would have the flexibility to determine what is operationally most suitable and efficient. To see how the principles would work in practice, we have provided a simplified example of how AEMO may choose to make its decisions on the following landscape pages. Note that this should not be seen as a prescription for how AEMO would implement enablement decisions but rather as an illustrative example.

### QUESTION 11: ENABLEMENT PRINCIPLES

Do stakeholders consider the proposed enablement principles to be appropriate and adequate?

### Simplified example of AEMO enablement of system security

Suppose that the time is 13:00 on 1 January 2028. AEMO is determining which security contracts may need to be enabled for the trading intervals between 13:00 and 14:00 pm on 2 January 2028 for NSW (the ‘relevant trading intervals’). AEMO determines that it has the following contracts available in NSW:

**Table 5.2: Hypothetical contracts available for AEMO to enable in NSW**

| GENERATOR | SERVICES INCLUDED IN CONTRACTS | ENABLEMENT COST (FOR 1 HOUR DURING RELEVANT TRADING INTERVALS) |
|---|---|---|
| Blackwood BESS (300 MW) | • 500 MWs of inertia | $5,000 |
| Red Gum Hydro Plant (300 MW) | • 400 MWs of inertia<br>• 500 MVA of fault level at the Buronga node | $10,000 |
| Wattle Thermal Power Station (350 MW) | • 300 MVA of fault level at the Buronga node | $15,000 |
| Jacaranda Thermal Power Station (500 MW) | • 600 MVA of fault level at the Buronga node | $20,000 |

Note: For this example, all units in the table above are not yet bidding to be dispatched at 13:00 on 2 January 2026. Enablement costs include both start and running costs for the generators to be enabled during the relevant trading intervals.

By looking at pre-dispatch and forecast IBR generation based on weather data, AEMO estimates that the level of IBR that is likely to generated and could be dispatched in NSW on 1.00 pm on 2 January is 5000 MW.

Time passes, generators rebid, and at 06:00 on 2 January, AEMO forecasts that according to pre-dispatch, there will be:

- 7500 MWs of inertia in NSW
- 1500 MVA of fault level at the Buronga system strength node

during the relevant trading intervals between 13:00 and 14:00 on 2 January.

These levels of inertia and fault level are below the minimum security requirements that have been determined by AEMO. Also, there is some IBR that was initially forecast to be dispatched that would require additional system strength to be dispatched. AEMO enables two contracts to meet minimum security requirements, and one to allow for extra IBR dispatch. AEMO also determines that no NSCAS or transitional service contracts need to be enabled to ensure the system remains secure.

Table 5.3 shows these security gaps, the opportunities for additional IBR dispatch, whether contracts were enabled, and settlement amounts (assuming the average energy spot price over the relevant trading intervals is $10/MWh). Table 5.4 explains the reasons as to why AEMO enables the contracts to meet each need according to the principles outlined in section 5.4.3.

Table 5.3: **Summary of contracts enabled to meet security requirements and dispatch additional IBR**

| SECURITY NEED OR IBR OPPORTUNITY | SECURITY GAP | CONTRACTS ENABLED | SETTLEMENT (ASSUMING AVERAGE ENERGY SPOT PRICE OF $10/MWH) |
|---|---|---|---|
| **Inertia floor:**<br>8 GWs | 500 MWs | Contract with Blackwood BESS | • $10/MWh x 300MW = $3,000 from energy spot market<br>• Balance to receive agreed enablement payment of $5,000: $5,000 — $3,000 = $2,000 |
| **Minimum fault level at Buronga:**<br>1750 MVA | 250 MVA | Contract with Red Gum Hydro Plant | • $10/MWh x 300MW = $3,000 from energy spot market<br>• Balance to receive agreed enablement payment of $10,000: $10,000 — $3,000 = $7,000 |
| Stable voltage waveform requirement at Buronga for additional IBR | 800 MVA to relieve constraints to allow 400 MW of IBR to be dispatched | No contract enabled | N/A |
| Stable voltage waveform requirement at Buronga for additional IBR | 1100 MVA to relieve constraints to allow 800 MW of IBR to be dispatched | Contract with Jacaranda PS | • $10/MWh x 500 MW = $5,000 from energy spot market<br>• Balance to receive agreed enablement payment of $20,000: $20,000 — $5,000 = $15,000 |

**Table 5.4:** **Contract enablement reasons**

| UNIT | CONTRACT ENABLED? | SECURITY NEED AND REASON |
|---|---|---|
| Blackwood BESS | Yes | To meet the 500 MWs inertia gap at least cost. |
| Red Gum Hydro Plant | Yes | To meet the 250 MVA minimum fault level gap at least cost. |
| Wattle PS | No | After meeting minimum security requirements through enabling the two contracts above, AEMO notes that Wattle could relieve the security constraint preventing additional IBR dispatch. AEMO estimates what the effect on dispatch would be if it enabled Wattle PS:<br>• The enablement of Wattle PS is estimated to displace 100 MW of IBR.<br>• The total increase of IBR is 400 MW — 100 MW = 300 MW.<br>• The energy that would be provided by the Wattle Power station is 350 MW.<br>• As this is greater than the increase of IBR that would be dispatched, AEMO chooses **not to enable** Wattle Power Station in accordance with the IBR principle described in section 1.4.2. |
| Jacaranda PS | Yes | AEMO estimates what the effect on dispatch would be if it enabled Wattle PS:<br>• The enablement of Jacaranda PS is estimated to displace 250 MW of IBR.<br>• The total increase of IBR is 800 MW — 250 MW = 550 MW.<br>• The energy that would be provided by the Jacaranda PS is 500 MW.<br>• As this is less than the increase of IBR that would be dispatched, AEMO chooses to **enable** Jacaranda PS.<br>• AEMO instructs Jacaranda PS to bid online for the relevant trading interval. |

Note: This hypothetical and simplified example is only an indication of how AEMO may operationalise a process for the enablement of security contracts and is not intended to be a prescriptive method. Security service quantities, contract costs and generator parameters are hypothetical examples and are not necessarily representative of reality.

### 5.4.4 AEMO would provide enablement guidelines and regularly publish enablement outcomes

Stakeholders have consistently requested more transparency over the system's needs for security services and how these can be provided. Throughout the rule change process, stakeholders have emphasised the need for improved transparency. This can assist stakeholders to manage their plant and make investment and operational decisions in ways that help to provide system security in the most efficient way possible.

As such, under the proposed rules, AEMO would be required to consult on and publish an enablement guideline outlining its proposed approach to enabling contracts in the operational timeframe. This would set out, for example, how AEMO forecasts system security requirements, how it makes and communicates enablement decisions, and the timing of its enablement decisions.

In addition, to promote transparency for market participants AEMO would be required to, under the proposed rules, publish enablement outcomes each day outlining:

- which contracts have been enabled
- how frequently have contracts been enabled
- aggregated enablement costs over the day.

AEMO would also be required to report at least annually on its enablement processes and provide an assessment of whether minimum security requirements were effectively met. This could also include commentary on any potential improvements that could better promote the long-term interests of consumers.[128] The report would also provide useful information that can help assess the effectiveness of the transitional services framework on an ongoing basis prior to its sunset,[129] as well as the efficacy of the system strength, inertia and NSCAS frameworks.

> **QUESTION 12:** REPORTING REQUIREMENTS FOR ENABLING SYSTEM SECURITY CONTRACTS
>
> Do stakeholders support the Commission's proposal for AEMO to:
>
> - publish an enablement guideline
> - provide daily information about the type, frequency and cost of enabled contracts
> - publish an annual enablement report?

128 Proposed draft rule, clause 4.4A.7.

129 For more information see chapter 4.

### 5.4.5 TNSPs would be required to provide the necessary information to effectively schedule contracts

The proposed rule would also introduce requirements for TNSPs to provide AEMO with the contractual information required to effectively enable contracts in the operational timeframe.[130] This could include, for example, the costs of enablement and any operational parameters such as plant start-up time. The required information would be set out in AEMO's enablement guideline and TNSPs would be required to provide — and regularly update — any requested information with respect to planning timeframe contracts.

## 5.5 New enablement arrangements would commence on 2 December 2025

The Commission considers that the new enablement responsibilities, arrangements and obligations would commence on 2 December 2025, in line with the beginning of the first compliance period of the new system strength framework, and the proposed changes to the inertia and NSCAS frameworks. This would ensure that there is a method for enabling system strength contracts entered into under the new system strength framework — the proposed date coincides with when system strength service providers (SSSPs) are required to meet the system strength standard. To implement this intent, contracts set up under the new system strength framework and the proposed new inertia framework would be required to specify AEMO as the enabling party. [131]

AEMO would need to produce an enablement guideline and set up enablement systems and/or processes by this date. Although these would be new, the Commission considers that the flexibility provided to AEMO in the systems it uses for enablement allow for a less complex approach than under the previous OSM, which would help manage implementation timeframes. Further, it is possible that AEMO could draw on some of the previous OSM thinking in designing enablement arrangements, as the new arrangements are flexible, and some work done to date would likely be relevant.

Any system strength and inertia contracts that are entered into under the existing shortfalls frameworks after the final determination commences would need to ensure that AEMO is able to enable those contracts from 2 December 2025.

## 5.6 The Commission considers that the proposed approach to enablement would benefit power system security and contribute to the NEO

### 5.6.1 Promote power system security

The Commission considers that AEMO enablement of system security contracts would promote power system security by aligning with AEMO's overarching responsibility to maintain security, as discussed in section 5.3.3 and section 5.3.4. It would reduce the need

130 Proposed draft rule, clause 5.20B.6(c)(2) and 5.20C.4(c)(2).

131 Proposed draft rule, clause 5.20B.6(b1) and clause 5.20C.4(b1) — noting this obligation would only come into effect after the final rule is made. Any preexisting contracts under the inertia framework would retain any scheduling arrangements already specified in the contract and would not be non-compliant with this requirement.

for directions by ensuring that all security contracts are appropriately enabled when security needs arise, and ensure that AEMO has the tools necessary to maintain a secure system at least cost.

### 5.6.2 Emissions reduction impacts

As noted in section 1.5 we will use an emissions reduction criterion as part of the assessment framework for this rule change when the change to the NEO becomes law, and we are considering how we would apply this criterion.

The proposed enablement of system strength contracts to provide a stable voltage waveform for projected IBR would promote emissions reduction by supporting IBR to be dispatched more often, increasing the NEM's renewable penetration. Similarly, the proposed IBR principle whereby contracts are only enabled if they increase the dispatched level of IBR would ensure that enablement to meet the stable voltage waveform does not result in NEM-wide increases in emissions.

### 5.6.3 Appropriate incentives and risk allocation

The Commission considers that allocating enablement responsibility to AEMO aligns with AEMO's remit to ensure operational system security under the NER and the NEL. TNSPs would maintain their responsibility to procure and meet long-term security needs (guided by AEMO through joint planning). These arrangements would best align with existing security responsibilities.

The proposed principles for enablement (particularly the principle requiring enablement to meet security requirements at least cost) along with TNSPs' RIT-T requirements under the security frameworks, would help incentivise both TNSPs and AEMO to procure and manage security services at least cost to consumers.

Placing responsibility for enablement on AEMO would also promote economic efficiency by leveraging AEMO's visibility over dispatch and ability to consider inter-regional security service flows. AEMO would be able to consider inter-regional ESS flows and enable contracts across the entire NEM to result in a least-cost outcome.

The proposed arrangements would also provide clearer enablement responsibilities, enablement principles and information sharing requirements for AEMO and TNSPs, which would help provide guidance to TNSPs as they fulfil their responsibilities under the new system strength framework.

### 5.6.4 Transparency, predictability and simplicity

The proposed requirements for AEMO to provide an enablement guideline and publish regular enablement outcomes would provide stakeholders with clear information about enablement purposes and costs. This would allow TNSPs and service providers to better understand and predict how often they may be enabled and for which security reasons. Furthermore, AEMO enabling contracts instead of TNSPs would result in a consistent approach to enabling planning timeframe contracts across the NEM, rather than different approaches in each region.

### 5.6.5 Technology neutrality

The proposed enablement principles are technologically neutral. They would allow AEMO to draw upon a wide range of technologies to meet minimum security levels in operational timeframes as the energy mix evolves during the energy transition.

### 5.6.6 Flexibility and consistency with broader reform

The Commission has proposed these changes with flexibility in mind by outlining principles and guidelines that should be followed in enablement, rather than prescribing a specific or detailed operational method. The changes would allow AEMO to design enablement systems and processes as it sees best, and to modify them to meet changing security demands of the NEM during the energy transition.

The changes would also be consistent with the policy intents of the existing security frameworks. The proposed arrangements would require the levels of services enabled operationally to match the levels procured in the planning timeframe — that is, minimum levels for security in most cases; levels to support projected IBR in the case of system strength.

### 5.6.7 Implementation cost and complexity

As described in section 5.6, the Commission considers that the flexibility provided to AEMO, simplicity of the enablement approach, and drawing on preexisting work could help manage implementation cost and complexity.

# 6 IMPROVEMENTS TO THE DIRECTIONS FRAMEWORK

## BOX 12: KEY POINTS IN THIS CHAPTER

- The proposed reforms to system strength, inertia, NSCAS and the addition of a new NMAS framework should help reduce the number of security directions that are issued by AEMO.
- Directions should remain a last-resort mechanism, and should not be relied upon as a primary mechanism to procure services or system needs. However, as the system transitions and each region undergoes changes in generation mix, directions may be used at times to manage security as they have been in South Australia.
- As such, it is worthwhile taking opportunities to improve the efficiency and transparency of the directions framework in a way that contributes to the NEO.

**Basis of directions compensation**

- Directions compensation is currently based on the 90th percentile price for energy or FCAS over the preceding 12 months from when the direction was issued. However, the Commission considers that this basis has a high risk of under or over-compensating participants relative to the short-run marginal costs (SRMCs) of generators, risking increased costs for consumers. Moreover, the 90th percentile often does not accurately reflect the operating costs of generators, further risking under or over-compensation.
- The Commission is proposing to amend the basis of directions compensation to be a benchmark-based compensation framework, similar to the framework used during market suspension periods.
  - Directed participants who provide a compensable service would be entitled to compensation based on predetermined benchmark values that reflect their SRMCs, as determined through ISP data inputs.
  - A 15% premium would supplement the benchmark values to account for the variability of heat rates and other divergences between the estimated and actual costs on the day.
  - The ability for market participants to lodge a claim for additional compensation would remain.
- A benchmark-based compensation framework for directions is more likely to reduce the risk of under- or over-compensation, which would better balance the needs of generators and consumers. It also dissuades any bidding designed to withhold supply in order to be directed to earn higher revenue through directions compensation.

**Transparency of directions reporting**

- There are opportunities to improve the real-time reporting of directions through market notices by including more valuable information for market participants and interested parties.
- The laborious process of preparing a directions report for each direction event has resulted in a significant time lag between the issuance of a direction and its corresponding report being published.
- To address these issues and to improve transparency, the Commission is proposing improvements for both real-time and post-fact reporting:
  - At the time of issuing a direction, AEMO would be required to issue a market notice that identifies all directed participants and provides detail about the nature of the direction and the circumstances that have caused the need for a direction
  - AEMO would be required to prepare a detailed quarterly report that includes trends observed in directions in each quarter, AEMO's view on whether directions may be required in future reporting periods, and a breakdown of compensation amounts payable to each directed or affected participant. This would replace the requirement for AEMO to prepare a report for every direction event.
- To provide transparency in situations where there is a reliance on directions for system security, the Commission is also proposing that if a participant has been directed 30 times or more within a 12-month period, then AEMO will be required to include in its quarterly reports a description of why the directions were needed, any work being undertaken to avoid the need for continued directions, and whether the NMAS framework could be used to procure the security requirement.
- These proposed changes would likely improve the transparency of the directions framework by ensuring that participants receive valuable information in a timely manner, while also minimising the administrative burden on AEMO. They would also allow more opportunities for stakeholders to understand how AEMO is managing the power system during the decarbonisation and transition of the NEM.

## BOX 13: QUESTIONS FOR STAKEHOLDERS IN THIS CHAPTER

**Amending the basis of directions compensation to a benchmark-based framework** (see section 6.3)

- Do stakeholders support the Commission's proposal to adopt the market suspension compensation framework and apply it to directions compensation?

**Frequency and methodology of benchmark value calculation** (see section 6.3.1)

- Do stakeholders agree with the proposal to include annual updates to the schedule of benchmark values for the proposed new directions compensation framework, noting this would also apply to the market suspension framework?

**Directions compensation for energy storage systems** (see section 6.3.2)

- Do stakeholders consider that an estimate of the value of storage should form part of the automatic compensation payable to directed hydro plants and batteries?
- If so, should a proxy value, such as a relevant gas benchmark value based on the capacity factor of the storage system, be used? Should an alternative approach to estimating the value of storage be adopted for batteries?

**Improving market notices and directions reporting** (see section 6.5)

- Do stakeholders support the Commission's proposal to require AEMO to publish market notices when issuing directions that indicate information about the direction and why it is needed?
- Do stakeholders support the Commission's proposal to replace the existing directions reporting requirements with a quarterly reporting requirement? Is the information that would be included in quarterly direction reports useful (or not) to stakeholders?

This section covers the Commission's proposed amendments to the directions framework to improve the cost-efficiency of compensation, as well as to the obligations to provide greater value and transparency to market participants and consumers:

- Section 6.1 — Improving the directions framework would complement the proposed reforms to inertia, NSCAS, and the new transitional services framework, while directions would remain a last-resort mechanism
- Section 6.2 — There are opportunities to improve the efficiency of directions compensation to better reflect the operational costs
- Section 6.3 — Basing directions compensation on benchmarks rather than the 90$^{th}$ percentile price is likely to be more cost-effective and equitable
- Section 6.4 — The transparency of the directions framework could be improved to provide more valuable information for participants and consumers
- Section 6.5 — The Commission is proposing changes to reporting obligations to improve transparency
- Section 6.6 — The proposed changes would commence in mid-2024
- Section 6.7 — The proposed changes would contribute to the NEO by promoting power system security and greater transparency

## 6.1 Improving the directions framework would complement the proposed reforms to inertia, NSCAS, and the new transitional services framework, while directions would remain a last-resort mechanism

As the NEM decarbonises, new security needs are likely to arise in different regions. The proposed changes to long-term security procurement frameworks, outlined in chapter 3 and chapter 4, are aimed at ensuring these frameworks are proactive and effective in meeting security needs over the long-term.

However, in operational timeframes, there may be instances in the future where power system security is threatened due to security needs that have not been foreseen in the planning timeframe, or that have manifested in unexpected ways. In these cases, AEMO has the power to issue directions to registered participants to take any action as AEMO sees fit to ensure that the security of the power system is not threatened.[132] While the proposed new transitional services framework could be used by AEMO to alleviate the need for directions, this approach might only be used after directions have been repeatedly issued for the same need, or once the security need is better understood.

Although the power of direction is needed as part of the toolkit for maintaining system security, the Commission views directions as a 'last-resort' mechanism. They are not a primary mechanism to procure, provide or incentivise security services. The proposed changes to the long-term planning system security frameworks aim to reduce the reliance on directions for system security, thereby returning directions to a 'last-resort' mechanism.

While the intent is to reduce the total number of security directions in the future, as a transitional measure, directions may need to be issued to a wider range of generators and in regions other than South Australia. For example, new or unforeseen circumstances could cause a need for AEMO to direct a battery in Victoria, or a liquid fuel generator in Queensland — both of which have never been directed for security purposes before.

With this context, the Commission has revisited some of its recommendations that were made in the 2019 Interventions Review relating to the directions framework.[133] We have identified two key areas where amendments to the framework could be made to help make sure that it remains fit for purpose during the transition:

- The basis of directions compensation — by changing the basis of compensation to a benchmark-based framework, it is more likely to fairly compensate a wider range of generators and minimise costs to consumers.
- Real-time and post-fact directions reporting — by ensuring that market notices and direction reports provide valuable information to market participants and consumers in a timely manner, stakeholders better understand market outcomes and how system security is managed.

The Commission considers that these proposed changes complement the other reforms in this rule change to reduce over-reliance on directions, and would promote the NEO.

132 NER, clause 4.8.9(a)

133 AEMC, *Investigation into intervention mechanisms and system strength in the NEM*, final report.

## 6.2 There are opportunities to improve the efficiency of directions compensation to better reflect operational costs

### 6.2.1 The current directions compensation framework

Currently, participants who are directed for energy, market ancillary services and security services where energy is supplied incidentally are compensated based on the 90$^{th}$ percentile price. These services encompass:

- energy
- any market ancillary service (FCAS)
- a direct substitute for energy or FCAS
- a service where energy or market ancillary services are provided incidentally, including inertia, voltage control and system strength.

The 90th percentile price is calculated using the spot prices for energy or FCAS for the preceding 12 months from when the direction was issued. It is the level that 90% of all five-minute spot prices are below, or equivalently, 10% of spot prices exceed.[134] Directed participants may also choose to lodge a claim to AEMO for additional compensation to recover their direct costs if these are not covered by the 90th percentile price.[135] Direct costs include fuel, staff and maintenance costs that were incurred by the participant by complying with the direction.

A directed participant who does not provide a service that is listed above is entitled to 'fair payment compensation'.[136] Examples include:

- directions for batteries to maintain a particular state of charge and bid regulation FCAS to zero, to provide headroom[137]
- directions for units to provide System Restart Ancillary Services (SRAS).

These directed participants can lodge a claim to AEMO to recover direct costs (including fuel, staff and maintenance costs), loss of revenue, and costs of any relevant contractual arrangements.

### 6.2.2 The current compensation framework has a considerable risk of over- or under-compensating participants

The Commission considers that directions are available to AEMO as a 'last-resort' mechanism to ensure that the power system remains operationally secure. It is important for the relevant frameworks to incentivise the provision of power system needs — that is, the energy spot market should incentivise energy provision, FCAS spot prices should incentivise FCAS provision, and the long-term security frameworks should incentivise the provision of security services (given these cannot be specified in operational timeframes). Directions should not

134 NER, clause 3.15.7.

135 NER, clause 3.15.7B.

136 NER, clause 3.15.7A.

137 'Headroom' refers to energy or ancillary service capacity that is kept in reserve by a generator. For example, if a battery has a maximum output of 50 MW, but is dispatching 40 MW, then it has 10 MW of headroom. AEMO may desire headroom from batteries for the purpose of maximising frequency response capability, or to absorb excess generation to meet forecast supply shortfalls in the future.

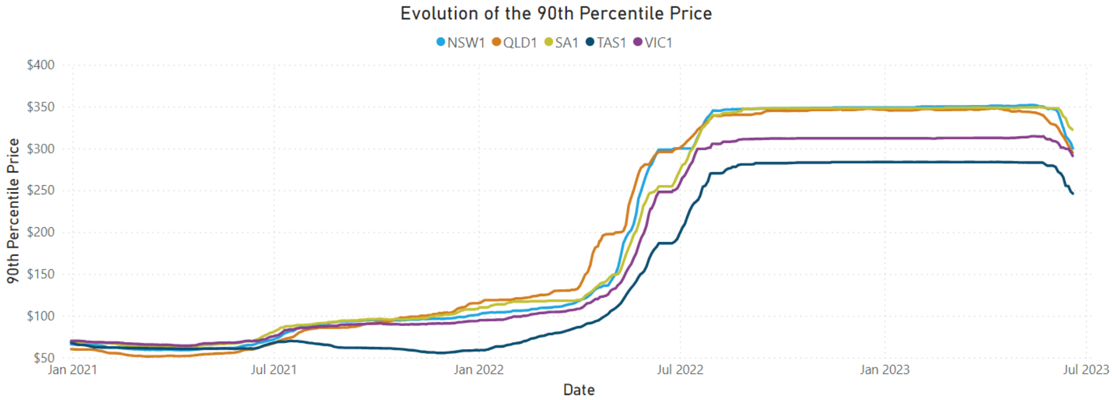
incentivise the provision of these services, and so generators should ideally be indifferent to being directed.

To reflect this principle, the Commission considers that the overarching aim of directions compensation is to put market participants in the position they would have been in had the direction not occurred. In general, this means reflecting the operational costs, or short-run marginal costs, incurred as a result of the direction.

Due to the high frequency and volume of directions, the current basis of directions compensation has been increasingly seen as an 'investment signal' to provide security services. Coupled with the volatility of the 90th percentile price and its relative lack of cost-reflectiveness, directions compensation is conflicting with the 'last-resort' intent of the directions framework.

The 90th percentile price has been highly variable in recent years due to high volatility in wholesale energy spot prices, exacerbated in 2022 by administered pricing periods during the NEM-wide market suspension. Figure 6.1 shows that the 90th percentile price varied between $55/MWh and $350/MWh between 2021 and 2023. This has resulted in directed participants receiving very different automatic compensation amounts for similar kinds of directions in different years. This variability leads to a high risk of over- or under-compensating a generator relative to their short-run marginal cost. It also makes it hard to predict how much compensation would be received if a generator was to be directed in the future.

**Figure 6.1: 90th percentile price by region**

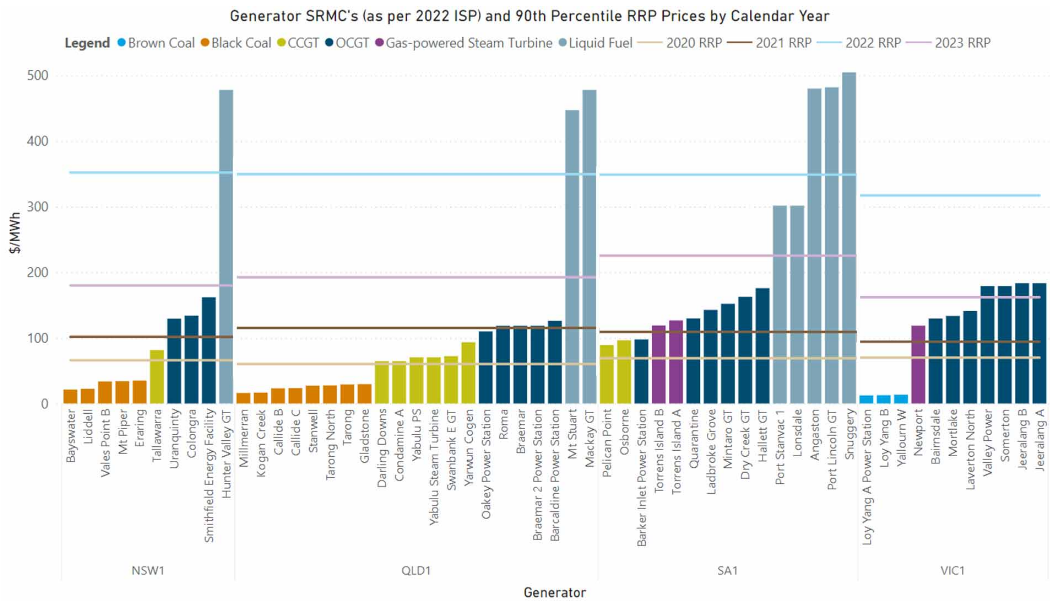



Source: AEMC analysis

Note: The 90th percentile price is calculated using a 12-month trailing window. For example, the 90th percentile price on 1 July 2021 is calculated using spot prices from 1 July 2020 to 30 June 2021.

To highlight the large risk of over- or under-compensating generators, Figure 6.2 shows the average 90th percentile price in each region from 2020 to 2023 as horizontal coloured lines, along with the short-run marginal costs (SRMCs) of each scheduled generator in the NEM (with the exclusion of Tasmania) shown as vertical coloured bars.

## Figure 6.2: Scheduled generator SRMCs and 90th percentile price by region




Source: AEMC analysis

Note: SRMC data is sourced from the 2022 ISP data inputs for 2023-24. The dates from the 2022 market suspension have been removed from the calculation of the 2022 90th percentile price.

Overall, the difference between the 90th percentile price and the SRMCs varies significantly between years and generator type. In 2020, the 90th percentile price was about $65-$70/MWh, which would not have been sufficient to recover the SRMCs of most combined cycle gas turbine (CCGT) and all open cycle gas turbine (OCGT) generators. Conversely, the 90th percentile price would have likely over-compensated all coal generators relative to their SRMCs, resulting in much higher payments than would be normal through the wholesale energy market.

If a directed participant considers that they have been under-compensated, they may lodge a claim for additional compensation to recover a shortfall in their direct costs under NER clause 3.15.7B. However, consumers do not have any mechanism to claim back costs in the event of over-compensation to directed participants. This inherent asymmetry between market participants and consumers means that the risk of over-compensating directed participants is not identical to the risk of under-compensating them.

Lodging additional claims for compensation can also impose a large administrative burden on directed participants and AEMO. Participants are required to submit claims within 15 business days, supported by evidence. AEMO often also needs to engage an independent expert to assess the claim and consult with the participants. It can take up to 30 weeks before the total amount payable is finalised, meaning that the participant does not recover their cost in a timely manner.

As a result, balancing the risks of over- and under-compensating directed participants is important to get right. The difference between scheduled generators' SRMCs across the NEM suggests that the 'one-size-fits-all' approach of the 90th percentile price is unable to appropriately balance these risks, as shown in Figure 6.2. More broadly, any particular percentile would be difficult to set — it would be too high for certain types of generators, but too low for others.

The 90th percentile price compensation framework could also influence energy bidding behaviours. Prolonged periods of low spot prices may — at an extreme — incentivise some generators to withhold supply with the aim of being directed by AEMO and earning higher revenue under 90th percentile compensation. This behaviour could risk the reliability and security of the power system by requiring AEMO to rely on directions to maintain security where plants would have otherwise cleared normally through the energy market.

## 6.3 Basing directions compensation on benchmarks rather than the 90th percentile price is likely to be more cost-effective and equitable

The Commission is proposing to amend the basis of directions compensation from the 90th percentile price to an approach based on predetermined 'benchmark values'. This aligns with one of the recommendations in the Commission's 2019 Interventions Mechanisms review, and with the market suspension compensation framework.

The Commission is proposing to adopt the market suspension compensation framework (as described in Box 14) for all energy and market ancillary service directions, as defined in NER clause 3.15.7(a2). Generators would be paid according to benchmark values based on the integrated system plan (ISP) data inputs that reflect participants' short-run marginal costs, with a 15% premium added to account for any variability in operating costs.[138]

### BOX 14: THE MARKET SUSPENSION COMPENSATION FRAMEWORK

During periods of market suspension, market participants are entitled to receive compensation based on predetermined 'benchmark values' that are calculated using the SRMCs of scheduled generators in each region. Using values contained in the ISP's 'Inputs and Assumptions' workbook, the SRMC of each generator is calculated using the following formula:

$$SRMC = (FC \times E) + VOC$$

- FC refers to the generator's fuel cost in \$/GJ
- E refers to the efficiency of the generator in GJ/MWh
- VOC refers to the variable operating cost in \$/MWh.

Benchmarks for each generator type in each region are calculated by taking a capacity-weighted average of each relevant generator's SRMC. For example, to calculate the

138 Proposed draft rule, clause 3.15.7(c) to (c5).

benchmark values for CCGT generators in South Australia:

- the SRMC of each CCGT generator in South Australia is calculated using the formula above and the most recent ISP data values
- the total capacity of all CCGT generators in South Australia is calculated
- using this total capacity, a capacity-weighted average of all the South Australian CCGT generator SRMCs is calculated.

Following the publication of each ISP, AEMO is required to calculate the benchmark values for each generator type in each region and publish a market suspension compensation schedule that contains the updated benchmark values.

The amount payable to a market participant is the relevant benchmark value multiplied by the sent-out generation of the participant, **supplemented by a 15% premium**. This premium accounts for the variability of heat rates between generators, plant loading, ambient temperatures and any other factors that would cause a divergence between the estimated and true costs of generators.

This compensation framework also applies to participants who are directed during market suspension periods, rather than using the 90$^{th}$ percentile price.

Market participants can also choose to lodge a claim for additional compensation to recover any direct costs not covered by the automatic market suspension compensation amount.

The benefits of applying the market suspension compensation framework to the directions framework include:

- Compensation based on the short-run marginal costs of generators would better reflect the different and varying operational costs of each type of generator, improving the framework's cost efficiency.
- It would likely reduce the risk of over or under-compensation to generators in prolonged periods of high or low spot prices, which would better balance the needs of consumers with directed participants.
- It would reduce any incentive for generators to withhold supply from the market during periods of high spot prices to earn more revenue by being directed, thereby promoting power system security, as the framework would aim to be indifferent to volatile market movements.
- Generators could provide feedback to AEMO on fuel costs to AEMO during its consultation on ISP inputs and assumptions, which would improve the accuracy and validity of the planning framework and is consistent with broader reform.
- By aligning the directions compensation and market suspension compensation frameworks, it would provide predictability and simplicity for market participants across intervention events.

**QUESTION 13: AMENDING THE BASIS OF DIRECTIONS COMPENSATION TO A BENCHMARK-BASED FRAMEWORK**

Do stakeholders support the Commission's proposal to adopt the market suspension compensation framework and apply it to directions compensation?

### 6.3.1 The benchmarks for compensation would be based on ISP data inputs and could be updated annually

The data used to calculate the benchmarks (such as fuel costs, efficiency data and variable operating costs) would be drawn from the Inputs and Assumptions Workbook that is prepared for the ISP. The values in the workbook are determined through extensive consultation between AEMO, independent consultants and experts, and market participants, and should be an accurate representation of the current and projected costs of each generator. While SRMC values may move in parallel with medium and long-term trends in the energy market, they should not necessarily represent a profitable level of revenue.

However, the Inputs and Assumptions Workbook is only updated every two years in line with the usual consultation process for the ISP. This means that once the benchmark values are calculated and published, they would remain unchanged throughout the next two years until a new round of consultation for the ISP begins. As the short-run marginal costs of generators can be relatively dynamic, applying the same benchmark value over a two-year period may risk inaccurate benchmarks being frequently applied for directions compensation.

As directions are generally more frequent than periods of market suspension, the Commission considers that there is a case to update benchmark values more than once every two years. One option is that the schedule of benchmark values could contain values for each year. For example, if AEMO publishes benchmark values in early 2024 following the 2024 ISP, then the schedule could contain a set of benchmark values for 2024 and another set for 2025. This would mean that the benchmark values used for compensation are updated annually, without requiring AEMO to conduct additional consultation for the ISP. Rather, forecasts and modelling from the Inputs and Assumptions Workbook would inform the annual updates of the benchmark values. The Commission has included these annual updates to the benchmark values in the proposed draft rule.[139]

If the market suspension compensation framework is adopted for directions compensation, market participants would be able to ensure that the values in the Inputs and Assumptions Workbook are accurate by providing their views and input to AEMO during its ISP consultation process. This would ensure values in the Workbook are based on realistic assumptions, are accurate, and are not based on outdated assumptions or studies.

139 Proposed draft rule, clause 3.15.7(c3). The proposed draft rule does not include the corresponding changes that could be made to the market suspension compensation framework in clause 3.14.5A so that both compensation frameworks include benchmark values that are updated annually and are aligned.

> QUESTION 14: FREQUENCY OF BENCHMARK VALUE CALCULATION
>
> Do stakeholders agree with the proposal to include annual updates to the schedule of benchmark values for the proposed new directions compensation framework, noting this would also apply to the market suspension framework?

### 6.3.2 Opportunity costs would not be included in directions compensation

In proposing a change to the basis of directions compensation, the Commission does not consider that opportunity costs should be recovered through automatic or additional compensation. Examples of generators incurring opportunity costs include a loss of revenue from failing to participate in an ancillary services market, or using a scarce resource when directed rather than at a time when wholesale prices are high.

The current directions compensation framework is not intended for participants to recover any opportunity costs incurred. This is reflected by the fact that claims for additional compensation may only include direct costs and not opportunity costs.[140] In the final determination for adopting the benchmark-based market suspension compensation framework, the Commission noted that:

> Compensation for opportunity costs is not supported since they do not form part of the directions compensation framework and the objective of the rule change request is to remove the incentive for generators to await a direction rather than participate voluntarily — hence the directions compensation framework is a key reference point.[141]

In line with the stated aim of directions compensation that participants should not view directions as a means to earn profitable revenue, the Commission has not proposed compensation for opportunity costs in direction compensation.

The Commission is aware that participants such as energy storage systems could incur relatively high opportunity costs compared with their direct costs. Using the formula in Box 14, the benchmark values that would be calculated for energy storage systems (for example, hydro plants and batteries), would be close to zero, as there are almost no fuel costs incurred by these systems. This may not reflect the true short-term operating costs of these plants, as water held in storage or headroom reserved in batteries is valuable to these participants.

This could be addressed by AEMO setting the benchmark values for hydro plants and batteries with reference to OCGT or CCGT benchmark values with similar capacity factors, to recognise opportunity costs. This was an approach previously suggested by the Commission in its 2018 final determination on Participant compensation following market suspension.[142] Using OCGT or CCGT benchmarks as a rough proxy for the value of storage may provide a

140 NER, clause 3.15.7B.

141 AEMC, *Participant compensation following market suspension*, final determination, p 47.

142 AEMC, *Participant compensation following market suspension,* final determination, p 37-39.

reasonable balance between ensuring there are no incentives to be directed, while minimising under-compensation risk to these generators.

While gas benchmarks may be suitable for estimating the value of hydro storage, they may not be suitable for a reasonable estimate of the value of battery storage, as the drivers of revenue from batteries (which determine the value of battery storage) are different to those for hydro plants. An alternative formula or methodology to estimate short-run marginal costs for batteries could be developed, but would likely depend on factors such as state of charge, average cycles per day, and market price volatility. These factors risk introducing significant opportunity-related costs into directions compensation.

If an exception were to be made to energy storage systems, and broad opportunity costs were to be included as part of the directions compensation framework, this would contradict the intent of directions compensation and would unfairly treat most scheduled generators who may incur both fuel and opportunity costs. Moreover, estimating opportunity costs is not a straightforward matter, and depends greatly upon whether the generator intends to participate in the market following a direction being revoked, as well as the estimation method used.

The Commission is interested in receiving stakeholder feedback about whether compensation for energy storage systems should include an estimate of the value of storage, and whether there may be alternative approaches to estimating the value of battery storage other than using relevant gas benchmarks for directions compensation.

> **QUESTION 15:** DIRECTIONS COMPENSATION FOR ENERGY STORAGE SYSTEMS
>
> Do stakeholders consider that an estimate of the value of storage should form part of the automatic compensation payable to directed hydro plants and batteries?
>
> If so, should a proxy value, such as a relevant gas benchmark value based on the capacity factor of the storage system, be used? Should an alternative approach to estimating the value of storage be adopted for batteries?

## 6.4 The transparency of the directions framework could be improved to provide more valuable information for participants and consumers

### 6.4.1 The current directions process, market notices and directions reports

Under the NER, AEMO has the power to issue a direction to any registered market participant to take a specified action to ensure that the power system remains reliable and secure.[143]

Prior to issuing a direction, AEMO must publish a notice of any foreseeable circumstances that may require AEMO to issue a direction.[144] These are usually published as publicly available 'market notices'.[145] AEMO must also estimate and note the latest time it would need

143 NER, clause 4.8.9(a1)(1).

144 NER, clause 4.8.5A(c).

to intervene in the market by issuing a direction if a market response does not alleviate the need for the direction.[146]

Once the latest time for AEMO intervention is reached without a suitable market response, AEMO issues a direction by notifying the relevant participant and publishes a market notice indicating that it has issued a direction, according to its directions procedure.[147] As soon as the need for the direction no longer exists, AEMO will revoke a direction by notifying the participant and publishing a new market notice.

Following a direction being issued, AEMO is obliged to publish a report 'as soon as reasonably practicable' that outlines detailed information about the direction (see Box 15).

### BOX 15: AEMO DIRECTIONS REPORT CONTENTS

As soon as reasonably practicable after issuing a direction, AEMO must publish a report that includes (but is not limited to):

- the circumstances giving rise to the need for direction
- the basis on which it determined the last time for that direction
- details of the changes in dispatch outcomes due to the direction
- the processes implemented by AEMO to issue the direction
- whether intervention pricing was applied during the direction[1]
- details of the adequacy and effectiveness of responses by generators to supply information to AEMO
- information about any non-compliance with the direction
- following settlement, a breakdown of the *compensation recovery amount* paid by participant type and region.[2]

Source: NER, Clause 3.13.6A

Note: [1] Intervention pricing is a form of scarcity pricing used when RERT is activated and when some types of directions are issued. Intervention pricing only applies for directions for energy or ancillary services (that is, for a market-traded service). It does not apply when a direction is required for inertia, system strength, voltage control or other non-market ancillary services.

Note: [2] The *compensation recovery amount* is the amount that must be recovered from consumers to 'top up' the trading amounts retained by AEMO to cover the cost of compensation.

### 6.4.2 Current market notices lack detail and specificity about system security

Currently, there are no explicit requirements in the NER for AEMO to publish a market notice when issuing a direction, nor any detail on what information AEMO should provide to the market. Market notices for directions are valuable to market participants because they can provide:

145 AEMO market notices are published at https://aemo.com.au/en/market-notices.

146 If AEMO expects that they will need to issue a reliability direction in order to meet operational demand a 'market response' usually refers to generators submitting rebids to signal that they are willing to supply the NEM with more energy than forecast. However, if AEMO expects that they will need to issue a security direction, then a market response may not exist, as the security need may be asset-specific, location-specific or require a particular combination of generators or loads to be online. This need may not be able to be alleviated by a typical market response.

147 AEMO, *Procedures for issue of directions and clause 4.8.9 instructions*, p 7.

- valuable information about security requirements under both normal and exceptional circumstances, and how their services could respond to alleviate these security needs
- information about how the direction has impacted regular market outcomes so that participants can manage risk and their impact on their operations.

However, currently published market notices often do not explain the system security circumstances that give rise to the need for direction, nor any information about the nature of the direction, beyond that the direction is needed to maintain system security (see the example of a market notice for a system security direction issued in South Australia on 12 July 2023 below).

> **AEMO ELECTRICITY MARKET NOTICE - Direction - SA Region - 12/07/2023**
>
> In accordance with section 116 of the National Electricity Law, AEMO has issued a direction to a participant in the SA region. For the purposes of the National Electricity Rules this is a direction under clause 4.8.9(a).
>
> The direction was necessary to maintain the power system in a secure operating state.
>
> AEMO may issue or revoke additional directions in order to meet the current requirement, unless sufficient market response is provided. A further market notice will be issued when all directions related to this requirement have been cancelled.
>
> The issue of the direction commences an AEMO intervention event. AEMO declares all trading intervals during the event to be intervention trading intervals, commencing from the interval ending 1705 hrs on 12/07/2023.
>
> Intervention pricing does not apply to this AEMO intervention event
>
> Manager NEM Real Time Operations

The Commission believes that there is a level of detail that could be included in market notices that would be likely to provide market participants with the valuable information needed to understand security requirements and market outcomes to position their plants operationally, while also ensuring that the administrative burden on AEMO to issue slightly more detailed market notices is not excessive.

### 6.4.3 Current reporting obligations do not ensure that participants receive information in a timely manner

In recent years, there has been a significant time lag between a direction being issued and its corresponding report being published given the large volumes of directions being issued. For example, AEMO issued over 1000 system security directions between mid-2020 and mid-2023.

Table 6.1 shows this time lag, with the last three SA direction reports being published up to 9 months after the direction was revoked.

The Rules do not specify a precise time frame by which reports must be published, which means that there is a significant time lag between the issuance of a direction and the report published in relation to that direction.

**Table 6.1: Dates of the issuance of SA security directions and publication of direction reports**

| DIRECTION REVOCATION DATE | PUBLICATION DATE OF DIRECTION REPORT |
|---|---|
| 16 October 2020 | 16 April 2021 |
| 22 October 2020 | |
| 26 October 2020 | |
| 5 November 2020 | |
| 11 November 2020 | |
| 20 November 2020 | |
| 3 December 2020 | |
| 9 December 2020 | 6 September 2021 |
| 14 December 2020 | |
| 25 December 2020 | |
| 1 January 2021 | |
| 19 November 2022 | 4 July 2023 |

Source: AEMO, Market event reports
Note: As of 18 August 2023, no directions reports have been published for system security directions in SA that have occurred since 20 November 2022.

This time lag was also noted by the Commission's 2019 Intervention mechanisms review, where we stated:

> The lack of a precise time by which reports must be published means that there is a significant timelag between the issuance of a direction and the report published in relation to that direction. The Commission acknowledges that AEMO has recently published a number of additional market event reports that were not available when the consultation paper was published. These latest reports cover system strength directions up to October 2018. Many directions have been issued since then for which reports are yet to be prepared.[148]

As of 18 August 2023, this statement is still applicable, with reports for all security directions since 20 November 2022 yet to be published.

AEMO also publishes information relating to directions in other publications, such as in their Quarterly Energy Dynamics reports. The Quarterly Energy Dynamics report for Q1 2023 notes

148 AEMC, Investigation into intervention mechanisms and system strength in the NEM, p 83.

the aggregate costs incurred for system security directions and uses of the RERT, as well as noting the percentage of time that South Australia had a direction issued.[149]

## 6.5 The Commission is proposing changes to reporting obligations to improve transparency

To improve the timeliness, transparency and value of directions information, the Commission is proposing the following changes to reporting obligations.

### 6.5.1 Including high-level detail in market notices provides valuable information to market participants

When issuing a direction, AEMO would be required to publish a market notice that includes high-level information about the direction, including:

- the identity of the directed participant(s)
- an outline of what the direction entailed, including the number of megawatts that was directed and details about any future dispatch targets, if applicable
- for system security directions, stating the system security service that was needed or identifying the security need, such as inertia, system strength, voltage control, or providing grid reference
- a brief description of the circumstances that necessitated the direction.[150]

By including this information, market participants are able to better understand the security requirements and needs of the power system in real-time, enabling participants to respond more promptly and efficiently to market intervention events. The detail of directed dispatch targets and security information also helps participants and other stakeholders understand the impact of directions on price formation and manage the impact on their own operations.

As AEMO already publishes market notices following directions, and the additional information outlined above is already known by AEMO at the time of a direction being issued, the extra level of administrative burden to implement these changes is expected to be minimal.

### 6.5.2 Directions reporting for specific events would be replaced by quarterly reporting to improve timeliness

As outlined in section 6.4.3, the current obligations on AEMO to publish a directions report have led to uncertainty about when market participants can expect to receive detailed information, due to the significant work required for AEMO to prepare and publish the reports. In the final report for the AEMC's 2019 Intervention review, the Commission agreed with stakeholder sentiment that greater transparency in directions reporting was required, and recommended that AEMO should publish its directions reports within a clearly defined period.[151]

149 AEMO, Quarterly Energy Dynamics Q1 2023 report, p 38.
150 Proposed draft rule, clause 4.8.9(k).
151 AEMC, Investigation into intervention mechanisms and system strength in the NEM, final report, p 84 – 87.

To better balance the needs of market participants with the administrative resources of AEMO, the Commission is proposing that AEMO:

- would no longer have to prepare reports for each direction event
- would instead be required to prepare quarterly reports that includes detailed information about directions in each quarter.

In its quarterly direction reports, AEMO would be obliged to publish the same information as outlined in Box 15 for each direction issued in the reporting quarter, but with the following additions:[152]

- AEMO's view on whether the circumstances that necessitated directions could materialise in the future, and whether any actions are being taken to manage power system reliability and security with the goal of limiting directions.
- any trends occurring with the use of directions, similar to those included in AEMO's Quarterly Energy Dynamics reports. This could include, but would not be limited to:
  - the percentage of time each region is under direction
  - aggregate historical costs of issuing reliability and security directions across the NEM
  - a breakdown of the number of directions categorised by system security need or reason.
- a breakdown of the amount of compensation payable to each directed and affected participant.[153] [154]

Quarterly reporting can help to reduce AEMO's administrative work by providing the flexibility for certain information to be aggregated across the reporting quarter, rather than unique reports being required after each direction. For example, if circumstances necessitating direction are the same for multiple directions across the quarter, a single explanation of the circumstances and security needs for those directions can be written, rather than preparing a detailed report for each event. Depending on the volume and nature of directions in each quarter, AEMO may choose how best to present information about general trends.

Instead of specifying a time limit for AEMO to publish its directions reports, the Commission is proposing that this simply be a quarterly reporting requirement. This timeframe aligns with increased transparency arrangements introduced in the 2019 *Enhancement to the RERT* rule change, which included a requirement for AEMO to publish a quarterly RERT report, covering both forward-looking and backward-looking costs.[155] Together, these reports would provide a clear picture of how AEMO expects interventions may need to be used in the future, with greater detail surrounding reliability and security issues that face the NEM.

152 Proposed draft rule, clause 3.13.6A(a1).

153 The Commission notes that some compensation amounts may not be finalised in time for the quarterly directions report, especially if an independent expert was required to assess additional compensation claims. In these cases, the Commission envisages that AEMO could note that the total amount is still being finalised, and then would include the final amount in a subsequent directions report once it is ready.

154 Affected participants are those participants whose dispatch targets have been changed as a result of a direction where intervention pricing was applied, and were not the subject of the direction. Affected participants are also eligible for compensation based on NER clause 3.12.2.

155 NER, clause 3.20.6.

The additional information would provide stakeholders with better insight into system security needs and any trends that may be occurring, providing greater opportunities for networks, generators and market bodies to identify efficient solutions to alleviate security needs across short- and long-term planning. The repeated directions reporting trigger (described below) also complements this aim by providing information about the complex circumstances that necessitated the repeated directions, as is currently the case with SA directions.

Including a breakdown of compensation payable to each directed and affected participant would also benefit market participants and consumers by providing:

- a more accurate metric on the costs of directions and ensuring that its effect on the wholesale market is better measured and understood
- market customers and consumers with clearer compensation information about their wholesale electricity costs
- greater transparency at the individual level to temper any potential inefficiencies from inefficient bidding behaviour.

The current *compensation recovery amount* that is reported (see Box 15) is somewhat opaque — this is the difference between the amount payable under automatic compensation and the amount AEMO retains from normal spot market prices. Reporting based on compensation recovery amounts alone can be an inaccurate signal to the cost of compensation, rather than reporting the total amount payable to each directed and affected participant.

### 6.5.3 The repeated use of directions would trigger a reporting requirement to promote transparency and consideration of long-term procurement options

The Commission is proposing that any repeated use of directions would trigger a reporting requirement for AEMO. Specifically, if a direction has been issued to a particular generator 30 times or more within a 12-month period, then AEMO would be obliged to:

- detail the circumstances that have led to the need for repeated directions
- provide details of any ongoing or planned investigation or joint planning with TNSPs to procure services to alleviate the need for directions
- state whether AEMO has, or intends to enter into, a contract to procure security services that would obviate the need for repeated directions (for example, a contract for the provision of inertia, system strength, or a transitional service).[156]

The details above should be published as soon as reasonably practicable, but no later than 6 months after the 30$^{th}$ direction to a particular generator. The proposed draft rule envisages that AEMO would include this additional information in its next quarterly directions report, avoiding the administrative burden of separate reporting processes.

This reporting trigger would provide greater transparency and information about any situations where directions are being used frequently and ensures that stakeholders are aware of and understand the work underway to alleviate system security issues. A repeated

156 Proposed draft rule, clause 3.13.6A(c).

use of directions for a particular generator implies that there is potential for AEMO or a TNSP to enter into an inertia, system strength, NSCAS or transitional services contract. This requirement would trigger consideration of whether there are more appropriate long-term procurement arrangements that could avoid relying on directions in these situations.

### 6.5.4 Identifying participants in independent expert reports provides greater transparency for consumers

The Commission is also proposing to require that when participants lodge a claim for additional compensation, the accompanying independent expert report prepared under NER clause 3.15.7A or 3.15.7B should identify the relevant directed or affected participant who is lodging the claim. This proposed change would resolve a current contradiction of how the rules are applied with respect to the identity of participants and would assist in improving the transparency of directions compensation.

Under the proposed changes to market notices, directed participants would be identified in real-time when AEMO issues directions. Additionally, in current AEMO direction reports, the identity of directed participants and details of dispatch intervals are disclosed. Therefore, despite the identity of the directed participant remaining confidential in independent expert reports, it is relatively easy to determine the identity of the claimant by looking at the corresponding AEMO direction report. [157]

The Commission considers that this proposed change will clarify AEMO and the independent expert's obligations in identifying market participants, and will ensure that publications relating to directions compensation will assist the other proposed changes in improving the value of information provided and transparency to stakeholders.

> **QUESTION 16: IMPROVING MARKET NOTICES AND DIRECTIONS REPORTING**
>
> Do stakeholders support the Commission's proposal to require AEMO to publish market notices when issuing directions that indicate information about the direction and why it is needed?
>
> Do stakeholders support the Commission's proposal to replace the existing directions reporting requirements with a quarterly reporting requirement? Is the information that would be included in quarterly direction reports useful (or not) to stakeholders?

## 6.6 The proposed changes would commence in mid-2024

To give AEMO sufficient time to:

- adjust settlement systems for a new basis of directions compensation
- amend processes to issue and receive market notices

157 There is no explicit prohibition in the NER to keep the identity of a participant confidential. Rather, the independent expert must enter a confidentiality deed with the participant to ensure that commercially sensitive information is not publicly disclosed through its reports — see NER, clause 3.12.3(c)(8).

- prepare administrative processes to produce quarterly directions reports,

the Commission proposes that the changes outlined in this chapter would commence on 1 July 2024, to align with the start of the 2024-25 financial year. This would mean that the first quarterly directions report would need to be published by 1 August 2024, and would cover all directions that have occurred in the 2nd quarter of 2024.

## 6.7 The proposed changes would contribute to the NEO by promoting power system security and greater transparency

### 6.7.1 Promote power system security

If the basis of directions compensation was changed from the 90th percentile price to the proposed benchmark-based framework, it would reduce any incentives for generators to withhold supply with a preference to be directed to gain higher revenue through compensation. Frequent occurrences of such behaviour would threaten power system security, as AEMO would be required to continually rely on directions to maintain system security. By making generators as indifferent as possible to being directed, it reduces incentives for generators to be directed, relieving AEMO of some security risk, and ensures that directions are maintained as a last-resort mechanism.

Improving the directions reporting process through more detailed market notices and clearer directions reporting would also promote power system security. Market notices can give important information about system security issues in real-time, allowing generators who may be able to relieve security gaps to reposition their plant operationally to meet system needs. Quarterly reporting that includes AEMO's analysis of directions and the circumstances that have necessitated directions would also provide stakeholders with valuable information about power system security.

### 6.7.2 Emissions reduction impacts

As noted in section 1.5 we will use an emissions reduction criterion as part of the assessment framework for this rule change when the change to the NEO becomes law, and we are considering how we would apply this criterion.

While the proposed changes to the directions framework would not directly contribute to emissions reductions, they complement the overall aim of reducing over-reliance on directions through the proposed reforms to the security frameworks. As almost all security directions have been to thermal plants, this would contribute to emissions reductions while simultaneously providing fit-for-purpose frameworks for the energy transition.

### 6.7.3 Appropriate incentives and risk allocation

As directions compensation should not be viewed as an investment signal, compensation should not incentivise generators to prefer a direction over being cleared normally through the spot market or through a security contract. Amending the basis of compensation to a benchmark-based framework which reduces the risk of over-compensation would achieve this aim.

### 6.7.4 Transparency, predictability and simplicity

The proposed changes to the compensation framework would provide greater predictability about the long-term costs of directions, as benchmark-based compensation would be indifferent to volatile market movements. It would also increase simplicity of interventions compensation by aligning directions compensation with market suspension compensation.

The proposed changes to market notices and directions reporting would also promote greater transparency over how AEMO manages power system security, and provide stakeholders with useful information about the market. This would allow participants to understand security issues better, enabling them to make more efficient operational and economic decisions. Clearer compensation information would also allow costs to be better understood by participants and consumers and therefore would be more predictable.

### 6.7.5 Technology neutrality

The proposed benchmark-based compensation framework is designed to be technology neutral, with the method of benchmark calculation being the same for all types of scheduled generators. However, as directions may be issued to a wider range of generator types in the future, and to ensure that all types of participants are equitably compensated, there may be a case to compensate storage systems (hydro and batteries) differently (see section 6.3.2).

### 6.7.6 Flexibility and consistency with broader reform

The proposed changes in this chapter would reduce incentives for generators to be directed, providing greater power system security information to stakeholders, and incentivising the use of the primary security frameworks to meet foreseeable security needs.

Where directions may still need to be used in specific situations to meet security needs, AEMO would report on any work it is undertaking to reduce the use of directions, and whether it intends to use the transitional services framework or another security framework.

### 6.7.7 Implementation cost and complexity

The Commission has sought to reduce administrative burden where possible and draw on existing arrangements. We consider that the proposed changes to directions compensation would incur relatively little cost, as AEMO and participants already have systems in place for directions compensation, settlement, issuing market notices and reporting. The proposed compensation arrangements draw on existing processes in the ISP which determine benchmark values. Therefore, relatively minor changes to processes and systems are envisaged.

The relatively low implementation costs are likely to be outweighed by the market benefits provided through reducing over-reliance on directions, greater transparency, and reducing the risk of over-compensation to directed participants.

# A RULE CHANGE REQUESTS AND THE RULE MAKING PROCESS

The Commission received two rule change requests which both propose solutions to better value system services to deliver a secure system more efficiently. This chapter gives background on the two rule change requests and the rule making process:

- Appendix A.1 - Hydro Tasmania's rule change request.
- Appendix A.2 - Delta Electricity's rule change request.
- Appendix A.3 - The rule making process.

## A.1 Hydro Tasmania's rule change request

On 19 November 2019, Hydro Tasmania submitted a rule change request to address the shortage of inertia and related services through the creation of a new market for the procurement of 'synchronous services'.[158] Hydro Tasmania noted that these synchronous services include inertia, voltage control and fault level/system strength.[159]

This rule change request was part of seven rule change requests that the AEMC consulted on relating to the arrangements in the NER for the provision of services that are necessary for the secure and reliable operation of the power system. These are outlined in the System Services rule changes consultation paper, published by the AEMC on 2 July 2020.[160]

### A.1.1 Rationale for Hydro Tasmania's rule change request

Hydro Tasmania noted that system services have historically been provided by synchronous generators in abundance and without compensation as a by-product of electricity generation through synchronous machines being online. It also noted the transformation of the power system is seeing a reduction of these services being provided. Hydro Tasmania noted that, while these system services are currently not valued explicitly, they are still required for the secure operation of the power system. As such, there has been a corresponding increase of directions for generators to come online and provide these services to address the shortfall, which Hydro Tasmania noted is not a long-term solution that is consistent with the NEO.[161] Hydro Tasmania also noted that more efficient outcomes for the utilisation and operation of resources could be achieved if a mechanism was introduced to incentivise the provision of synchronous services.[162]

### A.1.2 Solution proposed in Hydro Tasmania's rule change request

Hydro Tasmania's proposed solution is to introduce a mechanism that would:[163]

158 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019.
159 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, p. 1.
160 AEMC, System services rule changes, Consultation paper, 2 July 2020.
161 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, p. 3.
162 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, p. 4.
163 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, pp. 2-3.

- explicitly value the provision of these system services
- provide dispatch targets for resources to provide these services, and
- coordinate the provision of these services along the dispatch of the energy and FCAS markets.

Specifically, Hydro Tasmania's proposed solution would:[164]

- alter NEMDE to shift generators' online status from the input side (the right-hand side - which is currently exogenous and cannot be optimised) of system security constraint equations to the output side (the left-hand side) to allow NEMDE to produce commitment targets for resources
- require resources to provide two additional bid parameters indicating the cost and availability to commit to be online, and
- allow NEMDE to produce dispatch targets for resources to commit online in an efficient manner.[165]

Following the release of the Commission's directions paper in 2021, Hydro Tasmania updated its original rule change request considering feedback received from stakeholders. Under the Rules, we must respond to the rule change request itself. However, we considered this submission to inform the draft rule determination released in September 2022.

### BOX 16: HYDRO TASMANIA REVISED APPROACH

On 21 October 2021, Hydro Tasmania provided a revised model in response to the Commission's directions paper.

The submission maintains the position that a MAS approach using co-optimisation in the spot market is more economically efficient than an NMAS approach and better fits into the NEM's decentralised design philosophy and the AEMC's long term vision for system services.

However, Hydro Tasmania identified revisions to the model in response to feedback from the Commission and AEMO. These revisions included:

- Discussion on how system security constraints that are non-linear could be incorporated into the approach with piece-wise linear approximations – including system configuration
- Rules for managing partial commitment decisions, and
- Examples on how the approach would create marginal prices for system security constraints, and how participants would earn revenue through this system.

According to Hydro Tasmania, these revisions meant that the MAS approach could be implemented immediately with the current version of NEMDE with the inclusion of some

164 Hydro Tasmania, Synchronous services markets, Rule change proposal, 14 November 2019, p. 2.

165 Hydro Tasmania's rule change proposal noted that a resource would be efficiently committed if it lowered the regional reference price. However the current objective function of the dispatch engine is to maximise the gains of trade of dispatch. Refer to clause 3.8.1(a) and (b) of the NER. Conversations with staff from Hydro Tasmania subsequent to the submission of the rule change request have confirmed that its preferred objective function of the proposed mechanism is maximising the gains of trade of dispatch, consistent with the current objective function of the dispatch engine.

additional generic constraints.

Source: Hydro Tasmania, Submission to the directions paper, pp. 2, 14, 14-16, 21.

Hydro Tasmania's initial proposal states that generators that come online be paid based on a pay-as-bid framework based on each resource's individual bid, rather than on a market clearing price (that is used for energy and FCAS markets).

Hydro Tasmania states that, through this proposed approach, the cost of implementation could be minimised by focusing on the system security constraints that bind most frequently in the initial implementation, with the change to the remaining constraints occurring on an ongoing basis.[166]

Hydro Tasmania considers that its rule change proposal contributes to achieving the NEO by supporting a more efficient utilisation and operation of resources, with less need for AEMO to manage system security through directions.[167]

## A.2 Delta Electricity's rule change request

On 4 June 2020, Delta Electricity submitted a rule change request relating to capacity commitment for system security and reliability services in the NEM.[168]

As with Hydro Tasmania's proposal, this rule change request was part of seven rule change requests received by the AEMC that relate to the arrangements in the NER for the provision of services that are necessary for the secure and reliable operation of the power system. These are outlined in the System Services rule changes consultation paper, published by the AEMC on 2 July 2020.[169] This rule change proposes changes to the NER to introduce a day ahead, ex-ante capacity commitment mechanism and payment to provide access to operational reserve and other required system security and reliability services.

### A.2.1 Rationale for the rule change request

In order to maintain a secure and reliable system, a range of technical and operational needs must be met at all times. As set out in its rule change request, Delta Electricity considers that the current tools for managing the procurement of system services are not sufficient.[170] Delta Electricity sets out in its rule change request its view that current market design is incomplete, with increasing levels of intervention from AEMO to achieve or maintain a required level of generation investment.[171] Delta Electricity considers that a key question is how the market can deliver efficient price signals to deliver the optimal level of system

166 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, p. 3.

167 Hydro Tasmania, Synchronous services markets, Rule change request, 14 November 2019, p. 4.

168 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020.

169 AEMC, System services rule changes, Consultation paper, 2 July 2020.

170 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020 pp. 5-6.

171 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 6.

security services and reliability while allowing for the continuation of the evolution in the generation fleet of the NEM.[172]

### A.2.2 Solution proposed in Delta's rule change request

Delta Electricity proposes to introduce a "day-ahead ex-ante market for capacity commitment" mechanism to address any or all of the system services for which AEMO has forecast a shortfall.[173]

Delta Electricity considers that the proposed solution offers a number of benefits over the status quo, including technology neutrality, price transparency, price discovery and competitive pressures in relation to the procurement of system services.[174]

Delta Electricity proposes that as part of the day-ahead pre-dispatch process, AEMO should determine the amount of operational reserve and other system services required to meet regional stability and reliability standards.[175]

The day-ahead timetable would allow all current providers of system services to participate. Eligible generators under Delta's proposal are scheduled generators, irrespective of technology type, that can provide the required system services. Delta also proposes that eligible generators are most likely (in the absence of the proposed rule change) to be subject to a direction.

Delta Electricity considers that these are "more likely to be generators that cannot fast start and have a non-zero minimum load on their primary fuel source but could be any generator type" .[176] The proposed changes would allow slow-start thermal generators to take into account the value of the system services they provide in their operating decisions, and may allow them to remain committed and dispatched at their minimum stable operating level, avoiding consequences for system security and reliability.

Under Delta Electricity's proposal, operators of generators may classify one or more of their generating units as a capacity commitment generating unit. Delta Electricity proposes that the ability of this generating unit to provide the relevant system security services would be assessed by AEMO at the time of registration.

Delta Electricity proposes that AEMO would monitor the short-term projected assessment of system adequacy and pre-dispatch schedule outcomes to identify the system services requirements on a regional basis.[177] Delta Electricity does not expect that market participants would be required to provide any additional information to this process.[178]

172 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 7.

173 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 10.

174 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, pp. 27-28.

175 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 15.

176 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 10.

177 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 11.

Delta Electricity proposes that market participants that have registered generating units as capacity commitment generating units would have "the opportunity but not the obligation to provide operational reserve offers". Delta Electricity is of the view that offers would fall into two fundamental categories:

- offers to commit capacity for the entire day (slow start), and
- offers to commit capacity for specific trading intervals in the day (fast start).[179]

The offer to commit capacity for the entire day would "allow AEMO to secure grid formation security services that span the entire day" well in advance of system needs. The offer to commit capacity for a specific trading interval could provide AEMO with access to system security services at particular times when shortfalls are identified.[180]

The combination of the offers accepted would provide a clearing price for capacity commitment for each trading interval in the day ahead. Delta proposes that any offer accepted by AEMO would obligate the following:

- the generator to remain committed and available for dispatch for the entirety of the period to which the offer applies
- generators committed under this process would not re-bid energy offers for the entirety of the period to which the offer applies
- AEMO would dispatch the generator at no less than its minimum stable operating level (MSOL) for all trading intervals in the period of the offer, and
- AEMO would pay to the generator the trading interval clearing price for the operational reserve capacity for all time intervals in the period in the offer.[181]

Delta proposes that each capacity commitment generating unit would provide an offer to participate in the operational reserve market that represents the minimum price in $/MWh that a market participant is prepared to accept to maintain the electrical output of that generating unit at the MSOL during the entire period to which the offer applies.[182] Delta notes that the generators would face the risk that the actual prices clear at lower levels than forecast.[183]

Delta proposes that AEMO would select the capacity commitment generating units that would deliver the required capacity commitment at lowest cost. This would occur in the following fashion. Firstly, AEMO would consider the time frame of the system services shortfall. If system services, including grid formation services, are required for the entire day, AEMO would first consider the "all day" offers to commit capacity and select the offers in order of

178 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, pp. 13-14.

179 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 14.

180 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 14.

181 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 14.

182 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, pp. 14-15.

183 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 15.

lowest cost to highest cost until the system security objectives are met for all trading intervals where no specific offers are made.[184]

For all trading intervals where system services shortfalls remain, AEMO would then select specific trading interval offers from lowest cost to highest cost until system security objectives are met for each trading interval.

Delta Electricity notes that in the event that more than one specific security service is needed for a day, then AEMO would co-optimise a solution to meet all required system services at least cost.[185] Delta Electricity notes that offers to provide other security services would reflect the cost to provide the service in appropriate units, for example, inertia offers would be on a $/unit basis for the period of the offer, given the particular properties of that service.

Delta Electricity also notes that no intervention pricing would apply to capacity commitment generating units dispatched under the proposed mechanism. Instead, the clearing price of the mechanism would be applicable to the MW capacity that is successfully bid into the ex-ante operational reserve market.[186]

## A.3 The rule making process

The following outlines the key dates for this rule change process:

- Rule change request received — Hydro Tasmania — **19 November 2019**
- Rule change request received — Delta Electricity — **2 July 2020**
- Consultation paper published — **17 July 2020**
  - Submissions due — **13 August 2020**
- Directions paper published — **9 September 2021**
  - Submissions due — **21 October 2021**
- Rule change requests consolidated pursuant to s. 93 of the NEL — **2 February 2022**
- Draft determination and rule published — **22 September 2022**
  - s. 107 extension of time granted to publish draft determination and rule (due to complexity of issues) — **24 September 2020, 9 March 2021, 17 June 2021, 24 November 2021, 22 June 2022, 25 August 2022**
  - s. 108A report published giving reasoning for a rule not being made within a year of initiation — **17 June 2021**
- Directions paper published (this publication) — **24 August 2023**
- Final determination and rule expected completion — **21 December 2023**

184 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 16.

185 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 16.

186 Delta Electricity, Capacity commitment mechanism for operational reserve and other system security services, Rule change request, 4 June 2020, p. 18.

- s. 107 extension of time granted to publish final determination and rule (due to complexity and difficulty of issues raised by stakeholder submission to draft determination) — **22 December 2022, 25 May 2023**

# B BACKGROUND AND CONTEXT

The energy transition has presented a number of challenges and opportunities in ensuring that the NEM has the right mix of equipment to meet energy needs in a secure and reliable way. One of these issues is the need to ensure that the essential services system required (such as frequency, inertia, and system strength) are available to maintain system security. This appendix provides more detail on this, including:

- Appendix B.1 — The ESB's long-term vision for the power system
- Appendix B.2 — Current mechanisms used to manage security.

## B.1 The ESB's long-term vision for the power system

The long-term vision for the power system is an efficient, secure and reliable power system. As agreed by the market bodies and as set out in the ESB's post-2025 market design advice, the best way to achieve this includes explicitly valuing and pricing essential system services where possible such that they provide adequate investment and scarcity signals for participants.[187]

The ESB's post-2025 market design advice was to develop a long-term reform package with the focus on providing advice on long-term, fit-for-purpose market design options that could apply from the mid-2020s.

The ESB also set out that in considering changes to the NEM, ideally spot market arrangements combined with co-optimisation should be used where possible, and the market should progressively move towards spot market provision for services. However, there are some services that may be better suited to structured procurement where spot market arrangements may not be appropriate (either now or ever).

The ESB then made a number of recommendations relating to essential system services. Of particular relevance to these rule changes were those recommendations relating to structured procurement and scheduling mechanisms.

With the changing power system and resource mix, there are some supporting system services that are currently provided predominantly as a by-product of synchronous generation. At this stage of the transition, these services may not be easily disaggregated, quantifiable or specifically able to be defined, to allow for the formation of a spot market and may be best addressed through structured procurement.

The ESB therefore recommended operational and short-term procurement mechanisms be considered through these rule changes. Such mechanisms would allow AEMO to value, procure and schedule specific services and resources to help keep the system secure.

- New market-based arrangements to value the services needed to support the changing mix of resources in the NEM. These capabilities are currently 'bundled' in the provision of

187 ESB, Post-2025 Market Design: Final Advice to Ministers, Part A, 2021, https://www.datocms-assets.com/32572/1629944958-post-2025-market-design-final-advice-to-energy-ministers-part-a.pdf.

energy by the exiting thermal generation fleet. Four essential system services were identified for initial focus: frequency, inertia, system strength and operating reserves.

- New market mechanisms to support efficient scheduling and dispatch by AEMO. Learnings from the operation of these new markets and mechanisms will be important to understand how new technologies and resources with capabilities can continue to deliver these essential services.
- A range of supply and demand based technologies and resources with capabilities to deliver these essential services.

The rule change requests received by Hydro Tasmania and Delta Electricity therefore formed part of the ESB's ESS Scheduling and Ahead Mechanisms (SAM) workstream.[188] This consolidated rule change process is the avenue by which further consideration of issues raised through the development of the above recommendation is being progressed.

This directions paper outlines how the Commission has progressed this recommendation. In summary:

- The Commission proposed an operational short-term procurement and scheduling mechanism (the Operational Security Mechanism or OSM) in the OSM draft determination (see chapter 1 and chapter 2 of this directions paper, and the OSM draft determination published in September 2022).
- After carefully considering submissions to the draft determination, the Commission determined the OSM would be too costly and complex to develop and implement and would be unlikely to deliver the intended outcomes.
- Chapter 2 of this directions paper gives an overview of the OSM's design and the reasons for the Commission's revised direction. While the Commission still recognises there are efficiency benefits in individually valuing and procuring security services, given the current reality of system needs, this is not yet feasible in practice.
- The revised direction still addresses the underlying security issues resulting from the transition identified in the ESB process and the rule change requests.

## B.2 Current mechanisms used to manage security

There are a number of mechanisms outlined in the National Electricity Rules which AEMO can already use to ensure the NEM remains secure at all times. These currently include, but are not limited to:

- **Generator performance standards** – the NER sets out technical requirements for generators (and other equipment) connecting to the power system which help support power system security. Access standards are set for connecting generators. These relate to a wide range of technical requirements (Refer to Schedule 5.2 to the NER) to support power system needs during normal operating conditions, during disturbances, and immediately following disturbances. Technical requirements cover, for example, active and reactive power, voltage, and system strength.

188 ESB, Post-2025 Market Design final advice to Ministers, July 2021, https://energyministers.gov.au/energy-security-board/post2025.

- **Technical capability of future plant** – the technical capability of future plant is forecast over a 10-year horizon to assess system strength requirements. As per clause 5.2.5.15(b) of the NER, asynchronous generating units must have the capability to operate stably.
- **Inertia framework** – the AEMC introduced a framework in 2017 to ensure security critical inertia when regions are at risk of 'islanding' from the rest of the NEM.[189] Under this framework, AEMO is required to assess the minimum and secure operating levels of inertia for each region, the projected level of inertia in that region over the following five years, and the likelihood of the region becoming islanded. If AEMO identifies a projected shortfall in a region at risk of islanding, the relevant TNSP is required to procure the inertia or alternative frequency control service (including FFR) to meet this shortfall. Proposed investments by the TNSPs to provide inertia network services are subject to a regulatory investment test for transmission, as are any proposed inertia service payments.
- **System strength framework** – the AEMC's Efficient management of system strength on the power system rule included the ability NSPs to contract with non-network solutions (such as a privately owned synchronous condenser, or an existing synchronous generator) to provide system strength to meet the system strength standard. AEMO has the ability to enable these contracts to meet minimum operational requirements for system strength.
- **Ancillary services** – are used by AEMO to manage the power system safely, securely, and reliably. There are a range of different services to maintain key technical characteristics of the system processes:
    - **FCAS** – FCAS are used by AEMO to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency standards. There are a range of different responses available to maintain the frequency within the NEM frequency standards including generator governor response, load shedding, rapid generation, rapid unit unloading and automatic generation control.
    - **NSCAS** – non-market ancillary services that may be delivered to maintain power system security and reliability of supply of the transmission network, or to maintain or increase the power transfer capability of the transmission network. AEMO is required to assess NSCAS needs in the NEM for the upcoming five-year period. When AEMO identifies a NSCAS gap, the NER gives TNSPs the primary responsibility for having arrangements in place to address the gap. AEMO can acquire NSCAS only for security and reliability purposes, and only where AEMO considers that the gap will remain after receiving advice from the TNSP about its proposed arrangements to address the gap.
    - **SRAS** – are reserved for contingency situations in which there has been a major supply disruption or where the electrical system must be restarted. The available services for SRAS are general restart source and trip to house load.

189 Refer to clause 4.4.4 of the NER.

- **Integrated System Plan (ISP)** – AEMO publishes a whole-of-system plan every two years that provides an integrated roadmap for the efficient development of the National Electricity Market (NEM) over the next 20 years and beyond. It serves the regulatory purpose of identifying actionable and future ISP projects for TNSPs (which can address security issues), as well as the broader purposes of informing market participants, investors, policy decision makers and consumers.
- **Other system planning processes** – AEMO collects information from market participants and publishes a range of reports which address issues related to security of the power system. These include the Electricity Statement of Opportunities (ESOO), Energy Adequacy Assessment Project (EAAP), Short-term and Medium-term Projected Assessment of Adequacy (ST PASA and MT PASA), and the Summer Readiness report. Beyond this, there are also several publications related specifically to renewables and their impact on the power system.
- **General Power System Risk Review** – monitors risks over time through the publication of an annual review identifying and assessing risks to power system security. The review is developed by AEMO in collaboration with NSPs. Only a limited number of priority risks will be assessed in depth through each GPSRR.
- **Protected events** – are non-credible contingency events the Reliability Panel has declared to be a protected event. The category of 'protected event' was introduced in 2017 to give AEMO additional tools to manage certain high consequence non-credible contingency events. AEMO may use a mixture of ex-ante actions to manage a protected event declared by the Reliability Panel. These actions include the purchase of FCAS, constraining generation dispatch, and the use of an Emergency Frequency Control Scheme in order to maintain the frequency operating standards applicable to protected events.
- **Constrained optimisation process** – AEMO determines generation schedules and regional prices in the NEM through an optimal solution to maximise the value of trade using the 'least cost' combination of generation (or demand response) available. The solution supports a secure and sustainable operation by solving linear constraint equations that represent the system's physical restrictions.
- **Mandatory frequency response** – is a mandatory obligation for all scheduled and semi-scheduled generators in the NEM to help control power system frequency by activating existing capability to provide primary frequency response when a dispatch instruction is received.
- **Primary frequency response incentive arrangements** – provide frequency performance payments that encourage generation and load to operate their plant in a ways that help control power system frequency.
- **Interventions** – AEMO has various powers to intervene in the market to maintain security and reliability. One key intervention mechanism is the use of directions, which AEMO has been using significantly in South Australia. AEMO may issue directions to participants to maintain or re-establish the power system to a secure operating state.[190]

190 Refer to clause 3.14.4(e)(1) of the NER.

Directions are a tool primarily intended to be used as a last resort mechanism. Other interventions such as the Reliability and Emergency Reserve Trader (RERT) and instructions are also available to AEMO to return the NEM to a secure operating state.

# C SUMMARY OF STAKEHOLDER FEEDBACK

The AEMC published a draft determination on the OSM rule change on 21 September 2022. The paper invited stakeholder feedback on establishing an OSM in the NEM to co-optimise the procurement of security services, energy and FCAS, operating in parallel to the spot market.

Submissions closed on 17 November 2022. The Commission received a total of 21 submissions.

## C.1 Overview of stakeholder feedback

Submissions generally supported implementing a more transparent and efficient approach other than directions to address security gaps.

However, several material concerns were raised relating to:

- lack of service definition
- operationalising system strength
- revenue arrangements
- various other design elements of the OSM.

Further, AEMO identified detailed elements of the OSM it considered should be tested further, while the AER raised significant concerns about the scope of potential services to be procured, the objective function, and market power arrangements.

## C.2 The majority of stakeholders supported implementing a more transparent and efficient approach than directions

While stakeholders generally supported making a rule that was more transparent and efficient than directions for managing security, views varied on whether the OSM was the appropriate approach.

Some stakeholders supported the OSM as the broadly right approach, however, they raised various — often significant — design concerns. Other stakeholders agreed with the aims of the rule change but did not consider the OSM to be the right policy tool to achieve these aims. Several also questioned whether an OSM was an efficient alternative to directions. A few stakeholders questioned the need to value system services at all right now, preferring to 'wait and see' what happens during the energy transition.

Some stakeholders were concerned that an OSM could prolong the life of thermal generators while failing to incentivise investments in replacement ESS sources. These stakeholders considered longer-term procurement more effective at incentivising new investment. A related concern was the perceived potential of the OSM to delay progress towards individually specifying and valuing security services as per the ESB's vision, given it would have allowed ongoing operational procurement of 'bundled' security services.

## C.3 Stakeholders had concerns about the lack of service definition

Some stakeholders raised concerns that there was not a simple enough commodity for investors to interpret, affecting the ability of the mechanism to generate investment signals. Some considered that, given the OSM would have operationally procured existing system configurations, known technologies would likely be favoured over new providers and technology.

Other stakeholders raised concerns that without further work on defining services, the scope of procurement could grow too large. Some submissions recommended that services should be defined before the OSM could go live.

## C.4 Stakeholders raised concerns about operationalising system strength

Stakeholders asked for further clarification on how an OSM would enable effective interactions with system strength. Stakeholders also raised issues and questions on cost recovery, including the potential double-charging of consumers for system strength services through both the OSM and the system strength arrangements.

## C.5 Stakeholders raised concerns about revenue arrangements

Most stakeholders raised concerns about the complexity of the proposed revenue arrangements. Concerns from some stakeholders included that 'pay as bid' would not be as effective as scarcity pricing in incentivising operational decisions that provide security services.

Thermal generators noted that being unable to access energy prices after OSM enablement would make defending contracted positions challenging, and could create unintended interactions with the energy market.

## C.6 Stakeholders raised significant further concerns about design elements of the OSM

While several stakeholders supported the OSM as an interim measure, these stakeholders raised significant design feedback, questions and concerns in their submissions. This included (but was not limited to):

- requests for more clarity on the objective function, as well as querying whether this should maximise the value of trade or deliver minimum levels of services to ensure security
- questions about the accreditation of new entrants and technologies
- suggestions for, and concerns with, elements of scheduling design and timing, including gate closure and enablement
- a wide range of views on the best overall approach to pricing, with some viewing scarcity pricing or long-term contracts as having greater merit than the proposed pay-as-bid arrangements

- different suggested approaches to calculating revenue, including enablement costs and make-whole arrangements
- generally, stakeholders requested more detail on how the OSM would work — across scheduling, co-optimisation, and dispatch.

# ABBREVIATIONS

| | |
|---|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| BESS | Battery Energy Storage System |
| CCGT | Combined Cycle Gas Turbine |
| CESS | Capital Efficiency Sharing Scheme |
| Commission | See AEMC |
| FCAS | Frequency Control Ancillary Services |
| EBSS | Efficiency Benefits Sharing Scheme |
| ESS | Essential System Services |
| FFR | Fast Frequency Response |
| FOS | Frequency Operating Standard |
| IBR | Inverter Based Resources |
| ISP | Integrated System Plan |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEO | National Electricity Objective |
| NER | National Electricity Rules |
| NMAS | Non Market Ancillary Services |
| NSCAS | Network Support and Control Ancillary Services |
| NSP | Network Service Provider |
| OCGT | Open cycle gas turbines |
| OSM | Operational Security Mechanism |
| PEC | Project Energy Connect |
| PS | Power Station |
| Proponent | The proponent of the rule change request |
| RCP | Rules Consultation Process |
| RIT-T | Regulatory Investment Test for Transmission |
| RoCoF | Rate of Change of Frequency |
| RERT | Reliability and Emergency Reserve Trader |
| SRAS | System Restart Ancillary Services |
| SRMC | Short Run Marginal Cost |
| SSSP | System Strength Service Providers |
| ST PASA | Short Term Projected Assessment of System Adequacy |
| TNSP | Transmission Network Service Provider |
| TUOS | Transmission Use Of System |
| VRE | Variable Renewable Energy |