AUSTRALIAN ENERGY MARKET COMMISSION

RULE

Draft rule determination

National Electricity Amendment (Enhancing reserve information) Rule 2024

Proponents

Iberdrola Australia
Delta Electricity

21 December 2023

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About the AEMC

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

Acknowledgement of Country

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

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Summary

This paper sets out the AEMC's draft determination to not implement an operating reserve market but to improve transparency of reserves

1 The draft determination is not to implement an operating reserve market, following analysis of the issues, stakeholder feedback to the directions paper and recent reforms. While an operating reserve market could provide greater visibility of market participants' reserve decisions helping to manage risks, the Commission considers that it would not offer any material performance improvements relative to the current arrangements, and would introduce significant additional costs for the market.

2 In the absence of an operating reserve market, the draft determination is focusing on improving transparency to better assess when reserves are needed during the transition.

3 We are also proposing that the detailed issues associated with regional and sub-regional frequency control ancillary services (FCAS) be considered through a separate rule change process.

The power system relies on reserves to maintain reliability

4 Meeting the National Electricity Market's (NEM) reliability and security objectives requires sufficient energy, frequency control services and reserves.

5 'Operating reserves' are defined as the capability to respond to large continuing changes in energy requirements, with minimum levels required for the system operator to maintain system security and reliability. Such reserves are currently provided 'in-market' informed by the collective decisions of many participants in aggregate. These are not explicitly priced, but implicitly. If there are not enough reserves available in the market then the reliable supply of energy to customers may be impacted or out-of-market backup reserves need to be purchased.

The issues raised by the rule change requests and AEMO's technical advice

6 The NEM is currently undergoing a transition as capacity-limited thermal generation retires and more weather-dependent and energy-limited variable renewable energy (VRE) enters the system.

7 This changing risk profile gives rise to an increase in variability and uncertainty in the power system, particularly as more VRE generation is adopted. These issues in the power system have been highlighted in the rule change request made by Iberdrola and Delta, as well as by the Australian Energy Market Operator (AEMO) in its technical advice.

8 In response to these issues, each rule change request proposes that a version of an explicit 'operating reserve market' should be introduced to meet future reserve needs.

9 The rule change requests were consolidated on 5 October 2023 pursuant to section 93 of the National Electricity Law (NEL). The AEMC decided to consolidate its consideration of the rule change requests because both identify the need for new arrangements to schedule and procure essential system services as the proportion of VRE increases. The rule change request is continuing under the new name "Enhancing reserve information" which better reflects the direction of the rule change following the [2023 directions paper.]

The Commission's draft determination is not to implement an operating

reserve market

10 An operating reserve market would explicitly value reserves in the NEM by centralising reserves procurement. In August 2022, the Commission outlined its proposed direction not to implement an operating reserve market. This view was supported by modelling, that showed a fleet that evolves to firm renewables with very flexible storage technologies would likely be well-placed to manage variability and uncertainty as we transition.[1]

11 There was near unanimous agreement in response to the directions paper on the Commission's decision not to implement an operating reserve market.

12 The Commission's draft determination is to not implement an operating reserve market as it considers that:

- The current arrangements have met the need for reserves up to now, and, importantly, we consider they will continue to do so throughout the transition. The existing market arrangements, in our view, are sufficiently flexible to manage the potential for a transitory increase in reserve needs, notwithstanding that there may be some challenges as the transition proceeds.
- An operating reserve market would not offer any material performance improvements relative to the current arrangements and would introduce significant additional costs for customers.

The Commission's draft rule would improve current market arrangements

13 In the absence of an operating reserve market, the Commission is making a draft rule that would further support the current arrangements to value reserves during the transition. The draft rule would publish information on energy availability in the operational timeframe, including:

- **State of charge:** the energy availability of batteries (i.e. state of charge in MWh) would be published close to real-time, aggregated by region, and the following trading day by dispatchable unit identifier (DUID), to align with existing post-trading day publications.
- **Daily energy constraints**: the energy constraints of other scheduled plant types (hydro, gas and coal) would be aggregated by region and published daily (at the start of each trading day).
- **Maximum storage capacity**: storage participants would need to provide their maximum storage capacity (MWh) to AEMO in their bid and offer validation data.

14 This information, with the exception of maximum storage capacity, is already provided to AEMO by battery participants through supervisory control and data acquisition (SCADA) and energy constraints provided to AEMO by other scheduled plant types. The draft rule does not place onerous reporting obligations on either AEMO or market participants. It is designed as an improvement to further support any increased need for reserves as we transition and address how energy availability may continue to play a prominent role in the NEM, particularly as more storage assets enter the system.

15 The Commission considers that this information would support more efficient commercial and operational decisions, potentially leading to better provision of reserves through the transition. For participants, this information could assist in the efficient provision of reserves over shorter and longer durations. For example, information showing that a region has a low level of reserve duration (in MWh) available from flexible energy constrained sources (i.e. batteries) could:

1 See Appendix C of the 2023 Operating reserves directions paper: https://www.aemc.gov.au/sites/default/files/2023-08/directions_paper_2023.pdf

- signal to storage providers that there is a high value in charging (even at relatively high energy prices) in order to meet the energy needs and account for potential uncertainties later in the day
- signal to other capacity (such as gas generators) that there is a high value in turning on to provide flexible headroom to be available for uncertain events and provide energy over longer durations over the course of the day.

16 In response to the 2023 directions paper, most stakeholders supported this change. Stakeholders noted that increased transparency could lead to improved risk management and operational decisions. This was also supported by AEMO and the Australian Energy Regulator (AER), noting it could lead to more efficient bidding practices and is an important step towards broader consideration of energy-limited plant.

17 While the Commission considers that increasing the information on energy availability would assist the provision of reserves in both short and long timeframes as we transition, we recognise that there are trade-offs. This includes the potential risk of undesirable bidding outcomes associated with increased supply-side information transparency. The Commission is therefore interested in stakeholder views on whether there remains the potential for any perverse and unintended outcomes if information on energy availability is published at an aggregated level and implementation for state of charge information occurs on 1 July 2027. This is discussed more in section 4.4 and below.

Other changes proposed in the directions paper are not being progressed further through this rule change

18 As demand becomes more variable due to the increasing uptake of consumer energy resources (CER), as well as more variable energy sources are connected (such as wind and solar), there may need to be adjustments to support frequency stabilisation in a region following a rapid and unexpected change in VRE output.

19 The AEMC has had a substantial work program over the past several years that has reformed the frequency arrangements to be fit for purpose given the changing system and also introduced the indistinct event framework to help AEMO identify and manage weather-related events (see section 5.1.1 for more information).

20 One additional suggestion that has come to light in this rule change is the potential need to manage frequency due to rapid and unexpected changes in VRE output in a more cost-effective way by accessing FCAS through regional and sub-regional frameworks. In early 2023, Powerlink provided a submission to the Commission's 2021 Operating reserves directions paper, suggesting that regional and sub-regional FCAS procurement could be formalised within the Rules.

21 The Commission sought wider stakeholder feedback on this suggestion in its 2023 directions paper. We received a diverse range of feedback, with particular concerns that changes to the FCAS frameworks at a regional/sub-regional level might impact the global FCAS market, with questions around market power and cost recovery.

22 Some stakeholders also considered that given the materiality of this change, it is not considered an incremental improvement and should therefore, if implemented, be assessed through a dedicated rule change to avoid any perverse or unintended outcomes.

23 The Commission has investigated the Rules around regional and sub-regional FCAS and considers:

- the Rules currently enable AEMO to procure FCAS at a regional level and do not limit this to any specific event
- the Rules are not clear on whether the provisions for regional FCAS procurement extend to a sub-regional level.

24 In response to stakeholder views and further analysis, we consider regional/sub-regional FCAS raises a number of different issues that would be better looked at through a separate rule change process. We are therefore not proposing at this time to amend the Rules to specify when regional or sub-regional FCAS should be procured. If a rule change was submitted on these issues, then we would consider it at the time.

How to make a submission

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

26 **Due date:** Written submissions responding to this draft determination must be lodged with Commission by **5pm, 8 February 2024.**

27 **How to make a submission:** Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0295. 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.

28 You may, but are not required to, use the stakeholder submission form published with this draft determination.

29 Tips for making submissions are available on our website.[2]

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

31 For more information or to request a one-on-one discussion, please contact the project leader:

- **Project leader:** Shannon Culic
- **Email:** shannon.culic@aemc.gov.au
- **Telephone:** (02) 8296 1640

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

3 For more information see https://www.aemc.gov.au/contact-us/lodge-submission.

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This draft determination is to make a more preferable draft rule (hereafter "draft rule") in response to the rule change requests submitted by Iberdrola Australia and Delta Electricity. The draft rule would make a number of improvements to the current arrangements to enhance information and transparency that would further support the valuation of reserves during the transition.

The draft determination is not to implement an operating reserve market, in light of stakeholder feedback to the directions paper, recent reforms, and analysis on the sufficiency of current arrangements to elicit reserves.

We are seeking feedback on the proposed draft rule.

This chapter includes:

- Section 1.1 — the project considerations of variability and uncertainty in power system conditions
- Section 1.2 — an outline of the consolidation of the rule change requests
- Section 1.3 — a summary of how stakeholder feedback has shaped the draft rule
- Section 1.4 — an overview of the more preferable draft rule
- Section 1.5 — how stakeholders can make a submission

The following chapters of this paper set out:

- Chapter 2 — the Commission's assessment against the national electricity objective
- Chapter 3 — the Commission's draft decision is not to implement an operating reserve market
- Chapter 4 — increased transparency of energy-limited plant would further support the availability of reserves
- Chapter 5 — we consider regional and sub-regional FCAS raises a number of different issues that should be looked at through a dedicated rule change

In addition, the 2023 directions paper provides further background and context, including:

- Chapter 4 — addressing the need for reserves and how the Australian Energy Market Operator's (AEMO) technical advice has been important to the Commission's considerations
- Appendix A — an overview of the rule change request and related development
- Appendix C — modelling of the power system and the likely characteristics of the future fleet.

1.1 This project considers variability and uncertainty in power system conditions

This paper is part of the Commission's considerations of two rule change requests — from Iberdrola Australia (previously Infigen Energy) and Delta Electricity — that raise issues relating to the ability of the current energy and frequency control market frameworks to address variability and uncertainty in power system conditions in the transition. Both rule change requests put forward different models to value these reserves in the operational timeframe.[4]

Meeting the National Electricity Market's (NEM) reliability and security needs requires sufficient energy, frequency control services and reserves. 'Operating reserves' are defined as the capability

4 For more information on the rule change requests see appendix B.

to respond to large continuing changes in energy requirements, with minimum levels required for the system operator to maintain system security and reliability. Such reserves are currently provided 'in-market' informed by the collective decisions of many participants in aggregate. These are not explicitly priced, but implicitly. If there are not enough reserves available in the market then the reliable supply of energy to customers may be impacted or out-of-market backup reserves need to be purchased.

1.2 The rule change requests have been consolidated

The Iberdrola Australia and Delta Electricity rule change requests were consolidated on 5 October 2023, pursuant to section 93 of the National Electricity Law (NEL) using the project code ERC0295. The Australia Energy Market Commission (AEMC or the Commission) decided to consolidate the rule change requests because both requests relate to considering arrangements for forecast uncertainty and variability given the expansion of variable renewable energy (VRE). The consolidation also simplifies the engagement process for stakeholders.

Following the Commission's proposal in the directions paper not to implement an Operating reserve market and stakeholder feedback to the directions paper, the Commission has renamed this project from 'Operating reserve market' to 'Enhancing reserve information'. This better encapsulates the direction of the rule change as outlined in the directions paper.

1.3 Stakeholders have shaped our determination

In August 2023, the Commission sought stakeholder feedback on the proposed way forward on a potential operating reserve market.[5] In addition to the rule change request, AEMO's technical advice was also integral to the Commission's assessment of an operating reserve market.[6]

The Commission outlined its proposed decision not to implement an operating reserve market, which was supported by modelling. The modelling outlined in the directions paper set out that if we have investment in the right fleet then the current market arrangements will incentivise the assets to show up when needed in operational timeframes. While this rule change is not about investment, the integrated system plan (ISP) does provide further insights of the future fleet developed by AEMO for the purposes of determining the optimal development path, with other mechanisms being used to drive investment in the right fleet. A future fleet with firm renewables and flexible storage technologies:[7]

- will likely be well-placed to manage net demand uncertainty in operational timeframes (five minutes to an hour) so long as participants have sufficient storage to account for such uncertainties
- should be reasonably well-placed to manage net demand needs over the course of a full day, so long as sufficient depth of charge and other resources are available to manage the potential for longer duration events to occur.

The Commission also outlined two improvements outlined in the directions paper for stakeholder feedback:

1. **Develop and publish more information to the market,** with a particular focus on energy availability. This would involve AEMO receiving information on storage including state of

5 For more information see https://www.aemc.gov.au/sites/default/2023-08/Operating reserves directions_paper_2023

6 AEMO's Technical Advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO Technical Advice 2022.pdf.

7 For more information on the AEMC's modelling see Appendix C of the Operating reserves directions paper https://www.aemc.gov.au/sites/default/2023-08/Operating reserves directions_paper_2023

charge and publishing it in either pre-dispatch or dispatch, with the aim to address the need for more information on the flexibility and duration of plant. It could also include publishing energy constraints for all remaining plant types, including gas, hydro and thermal.

2. **Procurement of frequency control ancillary services (FCAS) at a regional level or sub-regional level.** This could allow for frequency stabilisation within a region following a rapid and unexpected change in VRE output, without being limited by interconnector headroom between regions. It could also allow for transmission infrastructure to be used more effectively and may improve network utilisation, potentially avoiding some transmission spend as we move through the transition.

We received 18 submissions in response to the directions paper.

There was near unanimous support from stakeholders on the decision not to implement an operating reserve market, with submissions noting the sufficiency of current arrangements to elicit reserves in the operational timeframe (see chapter 3).

We also received mostly support for improvement #1 (see chapter 4) and mixed feedback on improvement #2 (see chapter 5).

We also received some suggestions for additional improvements we could investigate in the absence of an operating reserve market. This was mostly around increasing transparency of operational forecasts (see appendix A).

1.4 The Commission has proposed a more preferable draft rule

Following stakeholder feedback to the directions paper as well as recent and ongoing reforms, the Commission's draft determination is consistent with that in the prior directions paper i.e. not to implement an operating reserve market.

As noted above, almost all stakeholders supported this direction. This was underpinned by general support for the existing market signals as being sufficient to incentivise reserves in the operational timeframe, with out-of-market intervention tools available as an emergency backstop. Several stakeholders questioned the need for a market that explicitly prices operating reserves and agreed with the Commission's position.

While we consider the existing market arrangements sufficient to continue to incentivise reserves as we transition, the Commission's draft rule makes a change to further support the availability of reserves.

The draft rule would publish the energy availability in the operational timeframe, including:

- **State of charge:** the energy availability of batteries (i.e. state of charge in MWh) would be published, close to real-time, aggregated by region, and the following trading day by dispatchable unit identifier (DUID), to align with existing post-trading day publications.
- **Daily energy constraints**: the energy constraints of other scheduled plant types (hydro, gas and coal) would be aggregated by region and published daily (at the start of each trading day).
- **Maximum storage capacity**: storage participants would need to provide their maximum storage capacity (MWh) to AEMO.

The Commission considers that the draft rule promotes the Commission's assessment criteria and the National Energy Objective (NEO) including:

- promoting reliability of the power system by supporting more informed decision-making
- improving transparency of supply-side information to assist the provision of reserves over both short and longer timeframes

- minor implementation costs given that this information is already provided to AEMO and can be published in existing channels.

The Commission's assessment framework and how the draft rule promotes the assessment criteria are discussed further in chapter 2.

With regard to the suggestion of procuring FCAS locally, stakeholders mostly supported AEMO procuring FCAS at a regional and/or sub-regional level, as required. However, while regional FCAS procurement is currently not precluded from the Rules, there was concern about how the AEMC would prescribe under what operating conditions AEMO should procure FCAS regionally and how it would interact with the global FCAS market. There were similar concerns around sub-regional FCAS procurement. Some stakeholders noted a need for the AEMC to investigate prescription of regional and sub-regional FCAS procurement within a dedicated rule change, to avoid any perverse outcomes or incentives.

In response to stakeholder views and further analysis, we consider regional/sub-regional FCAS raises a number of different issues that would be better looked at through a separate rule change process. We are therefore not proposing at this time to amend the Rules to prescribe when regional or sub-regional FCAS should be procured. If a rule change was submitted on these issues, then we would consider it at the time.[8]

1.5 We encourage all stakeholders and interested parties 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, in so doing, contributes to well-informed, high-quality rule changes.

Due date: Written submissions responding to this draft rule determination must be lodged with the Commission by **5pm, 8 February 2024.**

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0295.[9]

Tips for making submissions on rule change requests are available on our website.[10]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we consider are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[11]

Further opportunities for engagement: if you are seek further information on this project, please use the details below:

- **Project leader:** Shannon Culic
- **Email**: shannon.culic@aemc.gov.au
- **Telephone**: (02) 8296 1640

8 For information on how to make a rule change request see https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request.

9 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.

10 For more information see https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-changerequests/our-work-3.

11 For more information see https://www.aemc.gov.au/contact-us/lodge-submission.

You can also request the Commission to hold a public hearing in relation to this draft rule determination.[12]

Due date: Requests for a hearing must be lodged with the Commission by 11 January 2024.

How to request a hearing: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0295. Specify in the comment field that you are requesting a hearing rather than making a submission.[13]

12 Section 101(1a) of the NEL.

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

2 The draft rule would contribute to the energy objectives

The more preferable draft rule (hereafter “draft rule”) would promote the NEO because it would promote increased transparency of energy-limited resources to support reserve needs as we transition. It also provides a more flexible and low-intervention approach to managing reserve needs than an operating reserve market.

This chapter explains why the Commission has made its draft determination and the accompanying draft rule. It outlines:

- Section 2.1 — how the draft rule would promote the long-term interests of consumers
- Section 2.2 — how the draft rule furthers the system services objective
- Section 2.4 — how the draft rule meets the assessment criteria set out in the consultation paper.

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

The Commission is bound by the NEL to only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO.[14]

The NEO is:[15]

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

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[16]

2.2 The system services objective for considering issues related to system services

The system services objective has been developed by the Commission to assess whether system services rule changes contribute to the NEO.

It reflects the trade-offs that are expected when considering issues related to the provision of system services and it is outlined in Box 1 below.

14 Section 88 of the NEL.

15 Section 7 of the NEL. The NEO was updated on 21 September 2023 with the introduction of the Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Act 2023. We have applied the updated NEO in this draft determination. This is a change from our previous papers for this project, which referenced the old NEO.

16 Section 32A(5) of the NEL.

Box 1: The system services objective

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,
- short-run use of,
- longer-term investment in, generation facilities, load, storage, networks (i.e. the power system) and other system service capability, in the context of the transition to a net zero system.

Efficient short-run operation refers to factors associated with the ability of the service design option to achieve an optimal combination of inputs to produce the demanded level of the service at least cost i.e. for a given level of output, the value of those resources (inputs) for this output are minimised.

Efficient short-run use refers to factors associated with the ability of a service design option to allocate limited resources to deliver a service, or the right combination of services, according to consumer preferences or system need.

Efficient longer-term investment refers to factors associated with the ability of the service design option to continue to achieve allocative and productive efficiencies over time. This means developing flexible market and regulatory frameworks, that can adapt to future changes.

2.3 The Commission has made a more preferable draft rule

The Commission may make a rule that is different, including materially different, to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO.[17]

For this rule change, the Commission has made a more preferable draft rule. The reasons are set out in section 2.4 below.

2.4 The Commission considered the more preferable draft rule against the assessment criteria

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

- **Safety, security and reliability** — a reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence. Reliability strikes a balance between having enough supply in the system and the costs associated with that.
- **Emissions reduction** — the market and regulatory arrangements for reliability should efficiently contribute to the achievement of government targets for reducing, or that are likely to reduce, Australia's greenhouse gas emissions. We included this criterion because of the recent change to the NEO to include emissions reduction considerations.

17 Section 91A of the NEL.

- **Principles of market efficiency** — the market and regulatory arrangements should create more appropriate arrangements than directions for those participants whose presence is needed to maintain a secure operating envelope.
- **Implementation considerations**— 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.
- **Principles of good regulatory practice** — the market and regulatory arrangements for reliability should promote transparency and be predictable, so that market participants can make informed and efficient operational decisions. Regulatory arrangements must also be flexible to changing market and external conditions, to remain effective in achieving security outcomes over the long-term. Where practical, regulatory or policy changes should not be implemented to address issues that arise at a specific point in time.

These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request, for impacts within the scope of the NEO. The criteria have been updated recently to ensure consistency with the new NEO.

The Commission has undertaken regulatory impact analysis to evaluate the impacts of the various policy options against the assessment criteria (see appendix C).

The rest of this section explains why the draft rule best promotes the long-term interest of consumers when compared to other options and assessed against the criteria, including why our more preferable draft rule better promotes the NEO when compared to the AEMO's proposed solution and drafting.

2.4.1 Safety, security and reliability

As discussed in chapter 3 the Commission does not consider that an operating reserve service would have any material performance improvements, relative to the current market arrangements and would introduce significant additional costs for the market.

Investment signals are being addressed through work on market settings and government schemes (see section 3.5). An operating reserve market is not a tool to promote investment and may even dilute long-term signals that are helping to drive the development of flexible plant in the NEM.

Conversely, the draft rule aligns with the existing market arrangements and would support power system reliability through increasing supply-side information. Improving transparency to the market by publishing energy-limited information reduces uncertainty in market participants' operational decisions to respond to reserve needs. The Commission considers that these decisions are likely to improve market efficiency in response to events of short duration (five minutes to an hour) and longer durations (over the course of one day).

This improvement is an important step toward broader consideration of how energy-limited plant and batteries would contribute to system security and reliability throughout the transition.

2.4.2 Emissions reduction

Batteries are likely to be a significant part of the future generation fleet of the NEM as we transition away from emissions-intensive resources. It is crucial that these resources are properly valued and integrated within the power system to assist in addressing reserve and reliability needs during the transition to a net zero system. We consider that the draft rule is an important step towards the broader consideration of storage assets and energy limits within the reliability frameworks of the NEM.

2.4.3 Principles of market efficiency

We consider the proposed approach promotes efficient market design. Currently, participants face real-time risks in existing arrangements, who we consider are best placed to manage these, given that they face financial incentives to do so. We note that these risks imposed on the market (which may evolve as the power system transitions) should continue to incentivise participants to make sure there are sufficient reserves. This involves participants committing reserves to manage their financial risks, which in turn should meet the physical needs of the system.

We consider that a future characterised more by VRE forecast uncertainty would continue to have a relationship between financial risks and the commitment of reserves. As discussed in section 3.4, while an operating reserve market could provide greater visibility of market participants' reserve decisions helping to manage risks, the Commission considers that it would not offer any material performance improvements relative to the current arrangements, and would introduce significant additional costs for the market.

These additional costs arise from the risks that participants would likely encounter when participating in an operating reserves market. The presence of an operating reserves market may have the effect of splitting generator revenue across multiple markets in operational timeframes. While generators would still have the option to participate in both markets to recover their costs, the financial risks posed by the operating reserve market would be challenging for generators to manage as there would not be any viable means for generators to create revenue certainty or manage their costs through separate financial products. This lack of financial products to manage financial risks arises from the fact that AEMO must act as the central procurer in the operating reserves market and, as such, there would be no natural counterparties with whom participants could enter into hedge contract arrangements.

Furthermore, participants in an operating reserve market may face a range of compliance risks (depending on design) which they would likely factor into their decisions to participate and for which they may wish to extract a premium to manage this uncertainty.

There may also be a risk of over-commitment and additional costs. An operating reserve market would lock in reserves ahead of time (up to four hours) and pay these reserves to be on standby. However, the reserve need may be later resolved or decreased. In these instances, consumers would still pay for these reserves even when they are not needed.

In contrast, increasing information transparency of energy constraints and state of charge would retain these financial risks and in addition, would provide greater supply-side information to support more efficient bidding outcomes. This could assist in participant risk management and portfolio operation, potentially leading to more competitive behaviour.

2.4.4 Implementation considerations

The operating reserve market would be a substantial change, which would come with costs for both AEMO and participants. AEMO's technical advice sets out estimated costs. AEMO costs for the implementation of an operating reserve market were estimated as part of the NEM 2021 business case. Implementation costs were estimated to be high with impacts across NEMDE, pre-dispatch, IT, settlements and other areas. Upfront costs for AEMO are estimated as approximately $11.4m +/-40% and ongoing costs are estimated to be $7.8m (over a 10-year period).[18]

As noted above, there is also likely ongoing costs and the risk of an over-commitment of reserves.

In contrast, the cost of implementing the incremental improvement would likely be low, given that AEMO already receives this information from market participants, with the exception of maximum storage capacity. The draft rule would also allow AEMO to choose how this information should be published and could therefore be incorporated within existing mechanisms.

2.4.5 Principles of good regulatory practice

Ensuring flexibility

An operating reserve service constitutes a more centralised approach, which relies on the operator planning and procuring enough reserves to ensure reliability across operational timeframes. Because these reserves would be locked in ahead of time, some of the flexibility present in the current market where participants adjust their availability in response to new information would be removed. Such flexibility is important and means the market is adaptable to changing market and external conditions. It also helps prices reflect the actual costs of the system, given there is flexibility to adapt to the situation present at a particular time.

In contrast, the more preferable draft rule builds on the existing current market structure, which relies on participant self-commitment of resources rather than central procurement. The risk of over-delivery of capacity is faced by the market participants (rather than consumers). Over-commitment typically results in lower prices in the energy market for a short time period as there is oversupply and as the market adjusts to this period of oversupply.

The risk of under-delivery of reserves and energy is faced by consumers in the reliability of the system. The reliability settings (such as the market price cap) are designed to ensure that market participants face sufficient risks, in operational timeframes, to ensure they provide reserves and energy to a level of reliability that consumers value. Increasing transparency of energy availability would assist the flexibility of participants in providing reserves in the operational timeframe.

The draft rule is one step for storage assets and energy availability being considered in the NEM. The framework would be able to adapt as more rule changes and initiatives are developed and implemented. In particular, the AEMC's *Integrating price-responsive resources in the NEM* rule change is currently considering how to best integrate virtual power plants (VPPs) into the planning and operation functions of the NEM.[19] The Commission's draft rule would complement any changes on how VPPs are considered in the NEM through that rule change.

The Commission also understands that AEMO is currently progressing with the short term projected assessment of system adequacy (ST PASA) replacement project.[20]

AEMO's ST PASA replacement project is a comprehensive review of the pre-dispatch and ST PASA methodology. Commencing in 2019, AEMO has consulted widely with industry on the current value of pre-dispatch and ST PASA information to understand how to optimise these systems. While this project is still ongoing, the Commission recognises that it is providing valuable insights into how the industry identifies and manages short-term risks to the power system security and reliability.

18 This is based on the assumption that the scheduling of operating reserves would be performed by NEMDE, forecasting and STPASA redevelopment projects are able to provide necessary inputs to the determination of the ORDC and that the replacement of causer pays system can be leveraged for the settlement of the system.

19 For more information see https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem.

20 For more information see https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project.

This rule change has been designed to complement any changes to ST PASA as a result of that project.

Driving transparency, simplicity and predictability

Our proposed incremental reforms focus on improving transparency, which necessarily helps to make clearer the current complexity in the market.

The draft would build on current market arrangements to increase transparency of existing market information. These are simple changes that leverage current processes to provide transparency to the market on reserve levels over operational timeframes.

Making general market information widely available is typically beneficial. However, the provision of additional information needs to be for a purpose. Increasing the level of information in the market alone does not necessarily better assist market participants in making decisions.

The Commission considers that information related to energy constraints, as outlined in this draft rule, would be useful to market participants and would assist participants in their decision-making. The Commission recognises that there are trade-offs in increasing supply-side information. We consider that the benefits of increased transparency outweigh the potential risks.

The draft rule is also simple and predictable. It is simple to implement as it focuses on the information that is already provided by participants to AEMO through current PASA and SCADA reporting obligations. The publication of this information reduces some uncertainty participants have about making operational decisions related to responding to the reserve need. As discussed above, the Commission notes some potential for anti-competitive behaviour, however, acknowledges these risks can be mitigated by selecting an appropriate level of aggregation when publishing energy limit information. Therefore, the Commission considers the draft rule to be predictable in its operation.

3 The Commission's draft decision is not to implement an operating reserve market

Box 2: Key points in this chapter

- The rule change request notes that increasing variability and uncertainty in power system conditions, driven by the transition to greater penetrations of VRE generation, will lead to an increase in the need for reserves.
- To meet these needs, both rule change requests proposed that a version of an explicit 'operating reserve market' should be introduced.
- In 2022, the AEMC sought technical advice from AEMO on the design elements and merits of an operating reserve market.
- This technical advice helped form the basis of the assessment of an operating reserve market in the Commission's 2023 directions paper.
- There was near unanimous agreement in response to the directions paper on the Commission's decision not to implement an operating reserve market.
- While an operating reserve market could provide greater visibility of market participants' reserve decisions helping to manage risks, the Commission considers that it would not offer any material performance improvements relative to the current market arrangements and would introduce significant additional costs for the market.
- Stakeholders also agreed with this assessment, noting that an operating reserve market would likely impose large costs on consumers without providing any reliability improvements.
- The Commission also considers that the increased need for reserves is likely a transitional, time-specific issue tied to the early stages of the transition as we grow our understanding of the behaviour of new resources and asset types. More reserves could be required as a safety net as variability and uncertainty increases as we transition to a low- or zero-emission system.
- However, in the longer term, reserve needs are expected to moderate due to increases in geographic and technological diversity of the generation fleet, greater interconnection, and improvements to forecasting.
- The existing market arrangements, in our view, are sufficiently flexible to manage the potential for a transitory increase in reserve needs as the transition proceeds. In contrast, the cost and time to implement an operating reserve market is not commensurate with the tenor of increased reserve needs.
- To further support current arrangements, there have been a number of recent and ongoing reforms that are also addressing reliability and security needs in the NEM as we transition to a low- or zero-emissions power system, including mechanisms to drive investment in the right fleet.

This chapter covers the Commission's decision not to implement an operating reserve market. The chapter is structured as follows:

- Section 3.1— Energy reserves are not explicitly priced under current arrangements
- Section 3.2 — The issues raised by the rule change request and AEMO's technical advice

- Section 3.3 — We sought feedback from stakeholders on the Commission's decision not to implement an operating reserve market
- Section 3.4 — The Commission's draft determination is not to implement an operating reserve market
- Section 3.5 — Recent and ongoing reforms will continue to support the market.

3.1 Energy reserves are not explicitly priced under current arrangements

Reliability means that the power system has an adequate amount of capacity (generation, demand response and network capacity) to meet consumer needs. Reliability is delivered in the NEM through investment, retirement and operational decisions made by market participants, informed by data including that provided by AEMO and a set of reliability settings and standards. The framework is supplemented by a series of mechanisms that allow the system operator to intervene in the market in specific circumstances in order to maintain a reliable supply to customers.

A key component of the system is *energy reserves ('reserves')*, which are capacity that is not currently used to supply energy to meet demand, but is available and capable of changing to maintain the energy supply/demand balance in the near future. 'Operating reserves' are defined as the capability to respond to large continuing changes in energy requirements, with minimum levels required for the system operator to maintain system security and reliability. Currently, such reserves are provided both in-market and out-of-market:

- Reserves considered in-market are made up of capacity that is offered by market participants into the energy markets as being 'available' but which is not dispatched. This energy has the potential to be dispatched in response to changes in supply and demand. AEMO monitors the level of in-market reserves based on its forecasts and information provided by market participants.
- Out-of-market reserves are procured by AEMO. AEMO can procure out-of-market reserves if forecast reliability is projected to be outside the relevant standard.[21] If AEMO considers that the market has not or will not respond (with in-market reserves) to fill a reserve shortage, it can intervene to provide additional, out-of-market reserves. Out-of-market reserves are procured and then dispatched if required by AEMO.

If there are not enough reserves available in the market then the reliable supply of energy to customers may be impacted or out-of-market backup reserves need to be purchased.[22]

3.2 The issues raised by the rule change request and AEMO's technical advice

The NEM's physical reliability risk profile is undergoing a shift as the NEM transitions from being a capacity-limited thermal power system to being a weather-driven, energy-limited power system with declining thermal generation availability.

The changing risk profile gives rise to an increase in variability and uncertainty in the power system, particularly as more VRE generation is adopted. These issues in the power system have been highlighted in the rule change request made by Iberdrola and Delta, as well as by AEMO in its technical advice.

21 AEMC, 2020, the Reliability Standard, https://www.aemc.gov.au/sites/default/files/2020-03/Reliability Standard Factsheet.pdf.

22 For a detailed explanation of how the current arrangements incentivise reserves, see Chapter 2 of the AEMC's Operating reserves directions paper.

In response to these issues, the rule change request proposes that a version of an explicit 'operating reserve market' should be introduced to meet future reserve needs.[23]

3.2.1 AEMO provided technical advice on an operating reserve market

In 2022, the AEMC sought detailed technical advice from AEMO to support our assessment.[24]

AEMO's advice provided additional analysis on an operating reserve market including the:

- development of an operating reserve demand curve
- implementation of a causer pays cost recovery mechanism for the market
- reserves obligation and interaction with dispatch and other processes
- direct implementation costs and proposed timing of an operating reserve market.

In its technical advice provided to the AEMC, AEMO suggests that forecast uncertainty is expected to increase in the future power system, driven by growing VRE penetration, weather, participant availability, storage depth, and other causes. AEMO notes in its technical advice that it is already witnessing increased variability, uncertainty, and lack of headroom, and an asymmetry of risk between participants and the system operator in carrying out its role in meeting security and reliability requirements during times of high forecast uncertainty.[25]

AEMO's technical advice notes that it is difficult to predict whether the fleet and market will supply sufficient capability to respond to large continuing changes in energy requirements to avoid frequent AEMO intervention in the future. AEMO also notes that it is further unclear if the contract market will continue to drive commitment of resources, and in turn mitigate risk for the system operator at times of forecast uncertainty.[26] The AEMC acknowledges this view by AEMO, but as set out below in section 3.4 considers that our modelling of the future power system suggests that it will continue to drive commitment.

3.3 We sought feedback from stakeholders on the Commission's decision not to implement an operating reserve market

In August 2023, the Commission outlined our proposed direction not to implement an operating reserve market. As discussed further below, this decision was made in light of two underlying considerations:

- Our view that the current arrangements have met the need for reserves up to now, and, importantly, we consider they will continue to do so throughout the transition. The existing market arrangements, in our view, are sufficiently flexible to manage the potential for a time-specific increase in reserve needs, notwithstanding that there may be some challenges as the transition proceeds.
- That an operating reserve would not offer any material performance improvements relative to the current arrangements and would introduce significant additional costs for customers.

In response to the directions papers, stakeholders mostly agreed with the Commission's decision.

Several stakeholders noted the effectiveness of the current market arrangements to incentivise reserve needs in the operational timeframe.[27] For example, Shell Energy noted "generators and

23 For more information on the rule change requests see appendix B.

24 AEMO's technical advice is available at our website https://www.aemc.gov.au/sites/default/files/2023-02/AEMO Technical Advice 2022.pdf and see chapter 4 of the Operating reserves directions paper for further details on our response.

25 AEMO's technical advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO Technical Advice 2022.pdf.

26 AEMO's technical advice https://www.aemc.gov.au/sites/default/files/2023-02/AEMO%20Technical%20Advice%20November%202022.pdf.

27 These include submissions to the directions paper by Shell Energy (p.2); Alinta Energy (p.1) and CS Energy (p.2).

demand response providers do respond to tight supply-demand balance and make themselves available."[28]

The AER and CS Energy further noted that the implementation of 5-minute market settlement (5MS) further incentivises flexible reserves. The AER noted that "the introduction of 5MS should help to drive short-term signals for fast response resources such as fast start dispatchable generation and battery storage... the creation of such a separately priced market may dilute the signals established through 5-minute settlement which rely on direct financial incentives to deliver sufficient battery and generation in short-term timeframes."[29] Similarly, CS Energy also noted that "the shift to 5MS implicitly incentivises reserve flexibility and the new generation fleet exhibits greater flexibility than the assets they are replacing. This will be further complemented by the volume of dispatchable capacity investment expected under the CIS [capacity investment scheme]."[30]

Many stakeholders also noted that the benefits of an operating reserve market do not justify the costs.[31] For example, the Energy Users Association of Australia (EUAA) noted that "an operating reserve market does not appear to add any additional benefits to the market, and would likely impose additional costs on energy consumers to achieve the same results as the current market structure and is unlikely to result in additional reserve capacity."[32]

Some stakeholders also referred to the availability of out-of-market intervention tools to further incentivise the need for reserves as an emergency backstop, such as the Reliability and Emergency Reserve Trader (RERT) contracts, as well as the Retail Reliability Obligation (RRO), Projected Assessment of System Adequacy (PASA) and Lack of Reserve (LOR) information.[33] In addition, Delta, although agreeing with the AEMC's decision "still maintains the concerns it raised in its rule change proposal for the introduction of a new ramping service market, developed some four years ago, are still relevant."[34] While Engie "does not seek to dispute the conclusion" it considered that "some of the underlying assumptions in the qualitative analysis may benefit from further investigation over time... considers this will not impact the outcome of this rule change but will be important for the Commission's future work".[35]

However, not all stakeholders agreed with the Commission's decision. AEMO noted "the decision to implement an operating reserve comes down to a view as to whether the market will adequately provide for reserves without support from the market operator instituting a direct market service. AEMO considers this is inherently debatable and questions the definitive stance of the Commission."[36] AEMO further notes that "consistent with the technical advice, AEMO would consider the implementation of an operating reserve market with 1-4hr timeframes and strong compliance."[37]

The Commission acknowledges AEMO's feedback but considers that existing market arrangements provide sufficient incentives to participants to provide reserves in operational timeframes. The market arrangements place financial risks on participants to provide reserves

28 Shell Energy submission, https://www.aemc.gov.au/sites/default/files/2023-09/Shell, p. 2.

29 AER submission, https://www.aemc.gov.au/sites/default/files/2023-09/AER, p. 1

30 CS Energy submission, https://www.aemc.gov.au/sites/default/files/2023-09/CS Energy, p. 2.

31 Including the following submissions to the directions paper: AER (p.1);, EUAA (p.1); and Shell Energy (p.2).

32 EUAA submission, https://www.aemc.gov.au/sites/default/files/2023-09/EUAA, p. 1.

33 See submissions to the directions paper by Snowy Hydro (p.2) and EUAA (p.1).

34 Delta submission, https://www.aemc.gov.au/sites/default/files/2023-09/Delta_Electricity, p. 1.

35 Engie submission, https://www.aemc.gov.au/sites/default/files/2023-09/Engie, p. 1.

36 AEMO submission, https://www.aemc.gov.au/sites/default/files/2023-09/AEMO, p. 2.

37 AEMO submission, https://www.aemc.gov.au/sites/default/files/2023-09/AEMO, p. 2.

when needed. We consider that mechanisms are being used to drive investment in the right fleet, coupled with improvements to forecasting, will further underpin the strength of the existing arrangements. We also consider that the relationship between financial risks and the commitment of reserves will continue in a future comprised of higher levels of VRE. This is discussed in further detail below.

3.4 The Commission's draft determination is to not implement an operating reserve market

The Commission's draft determination is to not to implement an operating reserve market. This follows near unanimous agreement in response to this proposed direction in the 2023 directions paper.

Although AEMO noted in response to the directions paper that it is seeing instances of increased variability and uncertainty[38] we consider that these issues are likely specific to this part of the transition as the existing fleet retires and we transition to a new operating environment. In the longer term, this need is expected to lessen due to increases in geographic and technological diversity of the generation fleet and improvements to forecasting.

The Commission is however making a draft rule to enhance transparency, which would further support the current market arrangements to incentivise and value the provision of reserves in the operational timeframe (see chapter 4).

3.4.1 The benefits of an operating reserve market do not outweigh the costs

Following stakeholder feedback, the Commission's draft determination is consistent with that set out in the 2023 directions paper. An operating reserve market design should not be viewed as a simple 'add on' to the existing NEM design, but rather a fundamental change to the way that reliability needs are met in operational timeframes, potentially resulting in significant costs. It is important therefore to carefully consider the proposed benefits of such a market and whether these could be greater than those offered by the current arrangements.

An operating reserve service could provide greater visibility of market participants' reserve decisions to the market operator. This could help AEMO to mitigate risks should market participants not manage their risks well. However, we do not believe that participants will struggle to manage their risks as the transition proceeds and this was further supported by submissions to the directions paper, as discussed in section 3.3.

The current arrangements are based around providing information to the market on potential future reserves needs while also providing financial incentives (both through the spot market and related contract market) for market participants to best manage reserves in order to mitigate risk. We consider that these risks imposed on the market (which may evolve as the power system transitions) should continue to incentivise participants to make sure there are sufficient reserves to manage unexpected events. This involves participants committing reserves to manage their financial risks, which in turn should meet the physical needs of the system.

We consider that a future characterised more by VRE forecast uncertainty would continue to have a relationship between financial risks and the commitment of reserves. The value of an operating reserve market to help meet the system's need for reserves, over and above the current arrangements, therefore appears to be low.

38 AEMO submission, https://www.aemc.gov.au/sites/default/files/2023-09/AEMO

In addition, the Commission considers that an explicit operating reserve market is not a tool to provide investment signals. Other mechanisms are being used to drive investment in the right fleet. Indeed, there is a risk that such a market could dilute operational signals, particularly for the types of fast-start, responsive plant that would best respond to an increased need for reserves. If this is the case, then the implementation of an operating reserve service would be considered to be at odds with the direction of recent reforms, particularly 5MS, which involved moving to stronger signals to incentivise investment in fast-start plant (see more in section 3.5.1). It could also favour certain technologies over others. This view was also supported by submissions to the directions paper.

While a new operating reserve market may provide more visibility of reserve levels, it is unlikely that this would be translated into system-wide benefits, given an operating reserve service would likely result in greater costs being borne by market participants and passed on to consumers.

These would likely include direct costs, including implementation costs for AEMO and for market participants who may need to upgrade their systems to accommodate trading in a new market. There may also be indirect costs associated with an operating reserve market. For example, the costs of procuring operating reserves would need to be recovered from market participants and consumers. As AEMO would be the central procurer of operating reserves, there would be no natural counterparties with whom participants could enter into financial contracts to manage risks. These increased risks, combined with potentially strict compliance obligations on participants (depending on the design), could act as a strong disincentive to market participation or, at the least, the pricing of operating reserves at a premium to manage this uncertainty. These additional costs would be expected to flow through to consumers.

3.4.2 The Commission considers the increased need for reserves to be a transitional issue

While we recognise that the need for reserves may increase in coming years, we consider this is time specific and related to the early stages of the transition as we grow our understanding of the behaviour of new resources and asset types. Reserves could therefore be required as a safety net as variability and uncertainty increases as we transition to a low- or zero-emissions system. However, in the longer term, reserve needs are expected to moderate due to increases in geographic and technological diversity of the generation fleet, greater interconnection, and improvements to forecasting (expanded further below). In contrast, the cost and time to implement an operating reserve market is not commensurate with the tenor of increased reserve needs.

The existing market arrangements, in our view, are sufficiently flexible to manage the potential for a time specific increase in reserve needs as the transition proceeds. We consider that if we have investment in the right fleet then the current market arrangements will incentivise the assets to show up when needed in operational timeframes. We do not consider that the rule change request focuses on investment signals nor do we consider an operating reserve market as a tool to incentivise investment.

The projected diversity of the VRE fleet, along with battery and storage technologies, will likely decrease the impact of any net forecast errors and therefore unexpected events. The greater the geographical and technological diversity of the fleet, the less likely it would be that multiple VRE assets would be impacted by a particular weather system or event in the same way. This will be further supported by the capacity investment scheme (CIS), jurisdictional schemes as well as recent and ongoing rule changes to further address reliability needs as we transition and drive investment in the right fleet (see more in section 3.5).

Further, the Commission notes that both AEMO's and market participants' forecasting abilities should continue to improve over time with access to more data and analytical tools, potentially providing for stronger predictive modelling capabilities. These trends can limit the frequency and impact of unexpected events, and therefore moderate any increases in variability and uncertainty in power system conditions.

The ISP provides a view of the future fleet developed by AEMO for the purposes of determining the optimal development pathway.[39] The Commission also undertook market modelling to shed further light on the future generation mix of the NEM. The modelling tested how the power system may perform throughout the transition and whether there are potential future fleet mixes that are more or less robust to an increasing need for in-market reserves.

Key insights from the modelling indicate that the current fleet is not well suited to operation in a future with high volumes of VRE generation. However, a fleet that evolves to firm renewables with high flexible storage technologies will likely have sufficient flexibility and duration to manage uncertainty and variability into the future. Current data on investment trends, as discussed in chapter 4 of the 2023 directions paper, suggests we are heading towards such a fleet.[40]

3.5 Recent and ongoing reforms will continue to support the market

While the Commission considers that the current market arrangements are sufficient to meet our reserve needs as we transition, there have been a number of recent and ongoing reforms that are further supporting reliability and security needs in the NEM.

3.5.1 Five-minute settlement

In 2017, the AEMC made a final rule to change the settlement period for the electricity spot price from 30 minutes to five minutes.[41] This was implemented almost four years later in October 2021. Prior to this, prices were settled every 30 minutes to form a wholesale market ('spot') price, determined as the average of the previous six, five-minute dispatch prices. Since October 2021, five-minute settlement has been in place, aligning operational dispatch and financial settlement at five-minute intervals.

Five-minute dispatch provides stronger financial incentives for generators to quickly respond to changing demand conditions than under 30-minute settlement. This likewise provides a stronger financial incentive for investment in flexible resources required in a NEM with more variable net demand conditions. Early five-minute settlement observations indicate improved plant responsiveness on a five-minute-by-five-minute basis and improved investment cases for fast-start plant.[42]

3.5.2 Government schemes

These same price signals that incentivise participants to provide in-market reserves, drive participant investment decisions. High energy prices incentivise investment in the kinds of plant that can make reserves available to capitalise on those prices. The contract market provides a forward signal of wholesale prices, providing certainty to potential investors and encouraging participants to invest when prices are high.

39 AEMO's 2022 Integrated System Plan https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf.

40 For more information on the AEMC's modelling see https://www.aemc.gov.au/sites/default/2023-08/Operating reserves directions_paper_2023

41 For more information see project page https://www.aemc.gov.au/rule-changes/five-minute-settlement.

42 For more information on the observed trends of five-minute settlement see the Operating reserves directions paper https://www.aemc.gov.au/rule-changes/operating-reserve-market.

Many jurisdictions now have in place additional schemes to further encourage investment in flexible plant. For example, the NSW Electricity Roadmap is a 20-year plan to transform the NSW electricity system into one that is cheap, clean and reliable.[43] The Roadmap is enabled by the Electricity Infrastructure Investment Act 2020, and seeks to support the private sector to deliver at least 12 GW of new renewable electricity generation, and 2 GW of long-duration storage, such as pumped hydro.

In addition to jurisdictional schemes, the Commonwealth, state and territory ministers agreed in principle to establish the CIS. The Department of Climate Change, Energy, the Environment and Water describes the CIS as a:

> "national framework to drive new renewable dispatchable capacity. This will ensure reliability in the rapidly changing energy market into the future. This new revenue underwriting mechanism will unlock $10 billion of investment in clean dispatchable power."[44]

A series of competitive tenders for this capacity has been released since 2023. The Commonwealth Government will be seeking bids for clean renewable generation and storage projects to help fill expected reliability gaps. Projects selected will be offered long-term Commonwealth underwriting agreements for an agreed revenue 'floor' and 'ceiling'.

Over the long-term, the CIS will seek to provide market participants incentives to enable adequate dispatchable capacity to be available to meet future energy demand.[45]

3.5.3 Market settings

The NEM will require significant new investment in generation, demand response, and network capacity during the transition to a low-emission supply sector to supply consumers with the energy they demand as the incumbent thermal generation fleet progressively retires from service.

To support this investment, the various market price settings, including the market price cap (MPC), the cumulative price threshold (CPT) and administered price cap (APC) provide key signals and incentives.[46]

On 7 December 2023, the AEMC made a more preferable final rule to amend the market settings in the NEM for the period 1 July 2025 to 30 June 2028. The more preferable final rule:

- sets the MPC and CPT at the level recommended by the Reliability Panel (Panel) in the 2022 Reliability Standard and Settings Review (RSS Review) adjusted for inflation.
- sets the APC at $600/MWh, which is different from the Panel's recommendation of $500/MWh but consistent with its current value.

3.5.4 Integrating price responsiveness into the NEM

Households and businesses are increasingly taking up consumer energy resources (CER) such as batteries, solar panels and home energy management systems. CER is expected to play a significant role in the shift to a low- or zero-emissions system. These resources are increasingly

43 For more information see https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap.

44 Department of Climate change, Energy, the Environment and Water. Capacity investment scheme to power Australian energy market transformation, https://www.energy.gov.au/news-media/news/capacity-investment-scheme-power-australian-energy-market-transformation

45 For more information see https://consult.dcceew.gov.au/capacity-investment-scheme-public-consultation-paper.

46 For more information see https://www.aemc.gov.au/rule-changes/amendment-market-price-cap-cumulative-price-threshold-and-administered-price-cap.

being aggregated by energy service providers (retailers and aggregators) to form VPPs which are actively responding to price signals in the NEM.

These resources are currently not fully integrated into the planning and operation functions in the NEM. They could be more appropriately considered when determining how much energy demand needs to be met, how to meet this demand, and the price at which electricity is purchased. Network and wholesale market services could both be provided more efficiently if these resources were fully integrated. Over time, this would reduce the total cost of providing consumers with a reliable electricity supply and therefore decrease prices for all consumers.

The AEMC released a consultation paper in August 2023 on the potential benefits of better integrating these resources into AEMO's system planning and management. A draft determination is currently expected in 2024.[47]

47 For more information see https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem.

4 Increased transparency of energy-limited plant would further support the availability of reserves during the transition

Box 3: Key points in this chapter

- The Commission's draft determination is to make a draft rule to publish information on energy limits in the operational timeframe, including:
  - **State of charge information:** the energy availability of batteries (i.e. state of charge) would be published, aggregated by region, close to real-time, and the following trading day by dispatchable unit identifier (DUID).
  - **Daily energy constraints**: the daily energy constraints of other scheduled plant types (e.g. hydro, gas and coal) would be aggregated by region and published daily (at the start of each trading day).
- The Commission is also making a minor amendment to NER Schedule 3.1 to require storage participants to include their **maximum storage capacity** in their bid and offer validation data.
- This information, with the exception of maximum storage capacity, is already provided to AEMO by market participants, either through the SCADA system or daily bids through PASA.
- The Commission considers that increasing transparency on the energy availability of all plant types in the operational timeframe would further drive efficient commercial decisions and promote a market response on reserve needs as we transition to a net zero energy system.
- While the Commission considers that increasing the information on energy availability would assist the provision of reserves in both short and long timeframes as we transition, we recognise that stakeholders held some concerns on whether individual plant could be identified.
- The level of aggregation at which energy availability information is published should strike a balance such that competition risks are minimised, while market efficiency outcomes from information transparency is maximised.
- Given the dynamic nature of the NEM, it is likely that an appropriate level of aggregation is only possible for some plant type, such as batteries, when more plant of that type becomes operational in the system. The Commission therefore proposes the following implementation timeframes:
  - 1 July 2025: Publishing state of charge information for batteries the following day
  - 1 July 2025: Publishing daily energy constraints of other scheduled plant types (e.g. hydro, gas and coal).
  - 1 July 2025: Require storage participants to submit their maximum storage capacity to AEMO
  - 1 July 2027: Publishing state of charge information for batteries close to real-time
- The Commission is interested in stakeholder views on whether there remains the risk of any potential perverse outcomes and its proposal for implementation.

This chapter covers the Commission's proposal to increase transparency of energy limited plant, including publishing state of charge information in real-time and the following trading day. The chapter is structured as follows:

- Section 4.1 — The Commission's draft rule to publish energy availability information for all plant types in operational timeframes
- Section 4.2 — We sought stakeholder feedback on increasing transparency on energy-limited plant
- Section 4.3 — Publishing aggregated energy availability information is an improvement that would assist participants in making more informed operational decisions
- Section 4.4 — The Commission is interested in stakeholder thoughts on the risk of publishing energy availability
- Section 4.5 — Implementation considerations

4.1 The Commission's draft rule is to publish energy availability information for all plant types in operational timeframes

The Commission's draft rule is to publish information on energy availability in the operational timeframe, including:

- **State of charge:** the energy availability of batteries (i.e. state of charge) would be published by AEMO as close as practicable to real-time and also the following trading day in respect of the previous trading day (to align with existing post-trading day publications).[48]
- **Daily energy constraints**: the daily energy constraints of other scheduled plant types (e.g. hydro, gas and coal) would be published daily (at the start of each trading day).[49]
- **Maximum storage capacity:** storage participants would need to provide their maximum storage capacity (MWh) to AEMO in their bid and offer validation data.[50]

The Commission considers that this information would support more efficient commercial and operational decisions, potentially leading to better provision of reserves through the transition (see section 4.3 for more details on the benefits of publishing this information).

This information, with the exception of maximum storage capacity, is already provided to AEMO by market participants, either through the SCADA system or daily bids through PASA. The draft rule is not intended to place onerous reporting obligations on either AEMO or market participants. It is designed as an improvement to further support the increased need for reserves as we transition and to address how energy availability information may continue to play a prominent role in the NEM, particularly as more storage assets enter the power system.

4.1.1 This draft rule adopts new concepts introduced by the IESS rule

On 3 June 2024, the *National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No.13* (IESS Rule) commences. The IESS Rule makes substantial amendments to Chapter 3 of the NER, including redefining categories of market participant and types of generating facilities.

As the draft rule proposes a commencement date that is later than the commencement of the IESS Rule, the draft rule relies on, and builds upon, some of the concepts and definitions

48 Draft rule, rule 3.7G(e) and clause 3.13.4(p)(9)

49 Draft rule, rule 3.7G(c)

50 Draft rule, Schedule 3.1

introduced into the NER by IESS Rule. For example, the draft rule uses the new term 'scheduled bidirectional resource' which captures batteries, as well as pumped hydro facilities. However, in certain cases, the draft rule is intended only to apply to batteries and not to pumped hydro, and in those cases, the rule specifically excludes pumped hydro production units.

4.1.2 The draft rule focuses on energy availability information that is generally already provided to AEMO by participants

The Commission understands that AEMO already receives information on energy availability through existing arrangements, aside from that relating to maximum storage capacity. AEMO receives state of charge information through SCADA reporting, while daily energy limits are provided through participants' daily ST PASA bids (see more detail below).

State of charge information is currently provided to AEMO through SCADA

AEMO requires information to maintain its visibility of the system.[51] AEMO continuously determines and revises the limitations on the system, taking into account information on the prevailing and projected power system and plant conditions, and predicting the impacts of reasonably foreseeable events. Examples of information received include real-time information regarding electrical demand, the output level of generating systems, energy conversion model data for wind and solar forecasting, availability of demand response, system voltages and system frequency, power flows on major network elements and state of charge for batteries. State of charge information is currently provided to AEMO by market participants through SCADA every four seconds, in units of MWh.

The Commission's draft rule requires:

- relevant market participants (who are registered in respect of a battery) to make continually available to AEMO the state of charge of its battery[52]
- those market participants to provide the maximum storage capacity in respect of the battery[53]
- AEMO to publish this information to the market.[54]

There is currently no rule requiring batteries to report their maximum storage capacity. This information would assist AEMO in better understanding the upper limit of storage capacity available in the NEM. The Commission has made a minor amendment to Schedule 3.1 that storage participants include their maximum storage capacity in their bid and offer validation data, in MWh.[55] The Commission considers this amendment:

- aligns with the intent of this rule change to publish state of charge information in near real-time [56]
- would assist the future alignment and inclusion of storage capacity in ST PASA and IESS Rule implementation processes.

However, the Commission recognises that participants must provide AEMO at least six weeks notice if they wish to update their maximum storage capacity with AEMO.[57]

51 AEMO, 2020, *Power system requirements*, www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf, p.8.

52 Draft rule, rule 3.7G(b)

53 Draft rule, Schedule 3.1

54 Draft rule, rule 3.7G(c)

55 Draft rule, Schedule 3.1

56 Draft rule, rule 3.7G(e) and clause 3.13.4(p)(9)

57 Schedule 3.1(d) of the NER.

This draft rule does not include VPPs in the definition of battery at this stage. This is because AEMO does not currently have visibility of a VPPs state of charge in the same way as other batteries. This is currently a focus of the *Integrating price-responsive resources into the NEM* rule change which is investigating how VPPs can be fully integrated into the planning and operation functions in the NEM.[58]

Participants currently provide daily energy constraint information to AEMO through both PASA submissions

Market participants currently provide a view of their available generation capacity as part of their daily PASA initial bid (i.e. the generation capacity is provided to AEMO in the first trading interval of the trading day). Under clause 3.7.3(e) of the NER, each Scheduled Generator and Market Participant is required to prepare the following information on a daily basis for AEMO, as inputs to the ST PASA:

- Available capacity of each scheduled generating unit, wholesale demand response unit, scheduled load or scheduled network service for each 30-minute period, where available capacity is the total MW capacity available for dispatch under expected market conditions.
- PASA availability of each scheduled generating unit, wholesale demand response unit, scheduled load or scheduled network service for each 30-minute period, where PASA availability refers to the physical plant capability available within each trading interval.
- Projected daily wholesale demand response availability for *wholesale demand response units* that are *wholesale demand response constrained*
- Daily energy availability forecasts for energy- constrained scheduled generating units and energy constrained scheduled loads.

Daily energy availabilities are therefore currently provided through PASA by market participants to AEMO. We recognise that this is only provided when a participant has identified an energy constraint.

4.1.3 State of charge information for batteries would be published as close to real-time as practicable by region and the following day by DUID

As discussed above, AEMO already receives a range of energy availability information from market participants through both SCADA and daily bids (aside from maximum storage capacity). However, this information is not currently published.

The Commission proposes that:

- The energy availability of batteries (i.e. state of charge) would be published by AEMO as **close as practicable to real time, and also the following trading day in respect of the previous trading day.**[59]
- Daily energy constraints of other scheduled plant types (e.g. hydro, gas and coal) would be published at the **start of each trading day.**[60]

Publishing state of charge close to real-time could assist in the provision of reserves, for example, by signalling to storage providers the high value in charging in order to meet energy needs during the peak afternoon period (see section 4.3.2 for more information on the benefits of publishing this information in operational timeframes).

58 For more information see https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

59 Draft rule, rule 3.7G(e) and clause 3.13.4(p)(9)

60 Draft rule, rule 3.7G(c)

Under clause 3.13.4 of the NER, AEMO currently publishes a number of data points concerning activities of the previous day. This includes information on bids, ramp-rates and other prices across various operational time-periods across the previous day, at various levels of aggregation, including at a DUID level.

The draft rule amends clause 3.13.4 (p) of the NER, to include state of charge for bidirectional units, excluding pumped hydro production units. This means AEMO will publish what the actual state of charge information was for each battery, at the DUID level, for each trading interval in the previous trading day.[61]

For remaining plant types, there are practical limitations in aligning publication with state of charge. SCADA provides state of charge for batteries continuously to AEMO whereas energy constraints are provided to AEMO as part of participants' daily energy bids. Real-time reporting of energy constraints may introduce additional administrative burden for participants, with limited industry-wide value. We consider a practical first step would be to align publication of daily energy constraints with the current daily energy constraint information AEMO already receives. This would assist in promoting the provision of reserves over longer timeframes (over the course of the day) by signalling to participants the days where there is a tight supply/demand balance.

AEMO would need to determine the mechanism that publishes state of charge information to the market

The draft rule sets out that the state of charge information would be published close to real-time by AEMO.[62] However, AEMO would need to investigate the appropriate mechanism to communicate this information to the market. The Commission considers this could be published in dispatch or incorporated into current projects underway by AEMO such as the ST PASA replacement project.

The draft rule therefore requires AEMO to publish the information as close as practicable to real time, and at least once in each trading interval. Ideally, AEMO will be able to develop a method to publish the information in real time, but where that is not possible, it will be updated at least once every five minutes.

4.1.4 Daily energy constraints would be published by region for non-battery scheduled plant types

The draft rule requires AEMO to publish, at the start of each trading day, any energy constraints provided by certain participants under clause 3.7.3(e) of the NER.[63] For many days, there may be no energy constraints submitted by participants, and therefore no reporting of constraints required by AEMO.

AEMO is required to provide this information in respect of scheduled generating units and scheduled bidirectional units to the extent they comprise a pumped hydro production unit. Therefore, this would include coal and gas units, as well as hydro units, but not scheduled bidirectional units that are not pumped hydro (i.e. not batteries).

When AEMO publishes this information it must be aggregated by region to avoid revealing an individual participant's energy constraints and to reduce any risks of anti-competitive conduct (see section 4.4.2 for more information).

61 Draft rule, clause 3.4.3(p)(9).

62 Draft rule 3.7(G)(d).

63 Draft rule, rule 3.7(G)(c).

4.2 We sought stakeholder feedback on increasing transparency on energy limited plant

In August 2023, the Commission published a directions paper to seek stakeholder feedback on the merits of publishing information on energy availability of plant in the operational timeframe. Broadly, stakeholders were supportive of this option, however stakeholders noted some concerns that possible anti-competition risks could arise if the published information could reveal individual participant information.

In response to the directions paper, most stakeholders supported the proposed reforms to publish more information to the market.[64] Delta Electricity noted that "developing and publishing more information to the market, with a focus on energy-limited plant will increase transparency of information to the market and allow participants to make better-informed decisions."[65] Others expressed similar themes.

In addition, both market bodies also agreed with the Commission's proposal to increase transparency of energy-limited plant.[66] In particular, the AER noted "...this additional information has the potential to complement energy price information, allowing participants to make better decisions, especially around discharging and recharging energy storage. This could allow for wholesale market outcomes that are more efficient in the long term."[67]

However, there were some stakeholders who were cautious of this incremental improvement.[68] While the Australian Energy Council (AEC) agreed in principle with the proposal, they also considered that given the complexity of publishing different technology energy availabilities, such matters should be considered holistically with pre dispatch and ST PASA tools.[69] Snowy Hydro also noted some concerns stating "the proposal will lead to new compliance burdens on hydro and batteries, however to more effectively understand the impact we would support more detail being provided."[70]

There was also a strong preference from stakeholders for this information to be aggregated so that the state of charge or energy constraints of individual participants was not revealed.[71] Neoen noted in its submission that it "would be concerned about [energy limit] information being provided in the dispatch on an individual asset basis".[72] In contrast, Stanwell suggested that anti-competition risks may be low as, in its view, much of the energy-limit information that has been proposed by the Commission in its direction paper, is already publicly available, or capable of being readily inferred through participant websites and specialist third-party software applications. [73]

64 This includes submissions to the 2023 directions paper, Delta Electricity (p. 3); Alinta Energy (p. 1); Energy Australia (p. 2); Powerlink (p.1); Stanwell (p.2); and CS Energy (p.4).

65 Delta Electricity submission https://www.aemc.gov.au/sites/default/files/2023-09/Delta Electricity, p. 3

66 See submissions to the 2023 directions paper: AER (p.2); and AEMO (p.3).

67 AER submission https://www.aemc.gov.au/sites/default/files/2023-09/AER.pdf, p. 2.

68 This included the submissions to the 2023 directions paper from AEC (p.2) and Snowy Hydro (p.2).

69 AEC submission, https://www.aemc.gov.au/sites/default/files/2023-09/Australian Energy Council.pdf, p. 2.

70 Snowy Hydro submission https://www.aemc.gov.au/sites/default/files/2023-09/Snowy Hydro.pdf, p. 2.

71 This included the submissions to the 2023 directions paper from Neoen (p.1) and Stanwell (p.3).

72 Neoen submission https://www.aemc.gov.au/sites/default/files/2023-09/Neoen.pdf, p.1 .

73 Stanwell submission https://www.aemc.gov.au/sites/default/files/2023-09/Stanwell.pdf, p.3.

4.3 Publishing aggregated energy availability information is an improvement that would assist participants in making more informed operational decisions

Currently, participants rely on information published to the market to inform their operational decisions and help to guide efficient bidding behaviour. The Commission considers that increasing transparency of the energy constraints of all plant types in the relevant operational timeframe would further drive efficient commercial decisions and promote a more optimal market response on reserve needs as we transition.

4.3.1 Participants rely on market information to make informed commercial and operational decisions

Markets require a flow of clear, timely and relevant information to promote competition and efficient outcomes. The information available to participants is therefore important to ensure the efficient provision of energy, frequency and reserves services in the NEM.

Market participants take into account a variety of information sources to guide their operation decisions. This includes information published by AEMO, such as its forecasts, as well as other sources of information that enable participants to make predictions about the prevailing supply-demand balance and the need for reserves. The differences in bidding behaviour across market participants are dependent on market participants' own predictions about the future of the system and are expected to be fundamentally driven by:

- how participants interpret and incorporate the information published by AEMO into their own models
- the differing sources of information that feed into their models.

AEMO provides participants with a central source of market information. This data is useful in managing market volatility as it reduces uncertainty around particular elements of the state of the market and allows participants to make more informed decisions around the likely demand for their generation output at different times of the day.

4.3.2 Increased transparency on energy availability would support the need for reserves as we transition

In the directions paper, the Commission highlighted that both flexibility and duration are required to meet reserve needs. Flexibility is the extent to which a type of plant capacity's output can be adjusted or committed in and out of service. This includes the speed of response to start up and shut down, rate of ramping and whether such plant can operate in the full range of capability, or has restrictions (such as minimum generation requirements, or other limitations). Duration is the ability to sustain a response over extended periods (for example, over hours), influenced by fuel reserves or storage capacity.

There are two key timeframes that are relevant to the optimal delivery of reserves, especially with increasing VRE generation, batteries and flexible load on the power system. These are:

- relatively short timeframes (e.g. five minutes to one hour), where the flexibility of in-market reserves (ramping and headroom) is important (flexibility), and
- over the course of the day, where duration or reserves (energy in MWh) that can meet energy needs is important.

Increasing the visibility of plant availability in dispatch timeframes would assist in promoting a stronger market response to the need for reserves in both relatively short timeframes and over the course of the day. The increasing penetration of VRE generation[74] and the increased variability and uncertainty it brings make predicting the near-future reserve requirements more challenging. The publication of information that indicates the level of reserves in the system could help bring more certainty to market participants when making operational decisions to respond to reserve needs in the power system.

For market participants, this information could assist in the efficient provision of reserves over both shorter and longer durations. For example, published information showing that a certain region has a low level of reserve duration available from flexible energy constrained sources (e.g. batteries) could:

- signal to storage providers that there is a high value in charging (even at relatively high energy prices) in order to meet the energy needs and account for potential uncertainties later in the day
- signal to other capacity (such as gas generators) that there is a high value in turning on to provide flexible headroom to be available for uncertain events and provide energy over longer durations over the course of the day.

Shorter duration events could include a sudden reduction in output from several solar farms in a region due to unexpected cloud cover. Batteries have the capability to respond rapidly to such events, and given the short duration, can ensure the system is restored quickly. However, the expectation for batteries to always respond to short-duration events could lead to inefficient market outcomes. In the event that state of charge in the region is low, other plant types would also need to come online to provide sufficient capacity to meet the supply demand balance. Other plant types typically have far less flexibility than batteries and may take time to respond. In publishing state of charge information for batteries, other plant may have more certainty of market information and be more willing to make reserves available, thereby leading to more efficient outcomes.

Further, batteries are limited in their ability to respond to long duration events. Events that last over the course of a day are better responded to by plant with fuel reserves such as thermal, hydro and gas. Publication of daily energy constraints for such plant types provides some certainty to the market on the ability to respond to longer-duration events.

This information could therefore influence the decisions that participants make to commit reserves in operational timeframes. This could lead to improvements in the reliability of the system because reserves would be more likely to be physically committed when they are needed. The changes may also promote efficient outcomes, particularly productive efficiency outcomes, as a cheaper mix of capacity may be able to provide reserves, FCAS and energy.

Market participants also require a way of validating the outputs of their models that help determine their bidding decisions. AEMO currently publishes a range of historical information, including information about activities in the NEM in the day prior. This includes information on supply, demand, bidding and ramping.[75] Currently, state of charge information for batteries is not published the following day and the Commission suggests this information will become more relevant as more batteries are operational within the NEM. This information can be used by

74 The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO (Section 32A[5] of the NEL) available: https://www.aemc.gov.au/regulation/targets-statement-emissions

75 See clause 3.13.4 of the NER.

participants to further refine decisions made to prepare and respond to reserve needs as they arise.

Participants that are more informed on the state of the market can make more informed decisions about the range of potential future market outcomes over the trading day. Greater market awareness leads to productive efficiency gains by increasing the likelihood that the lowest cost generators will identify the available opportunities to bid into the market to maximise their revenue. Participants with greater market awareness are also better able to manage their risks which leads to lower costs passed through in wholesale market prices.

4.3.3 Potential benefits to the market in publishing battery state of charge information

As we continue with the transition to renewable energy, increased uncertainty in generation from solar and wind generators means there is an increased need for greater information to allow market participants to make more informed operational decisions to maintain reliability. The flexibility provided by battery technologies has been to date an effective means of matching variability in wind and solar output. However, the limited energy storage of batteries can also mean that they have the potential to introduce uncertainties in pre-dispatch.

This uncertainty arises from the changing availability of batteries as they generate and charge throughout the trading day. Batteries will typically bid as available to generate at maximum capacity (MW) unless they are fully discharged, in which case the battery operator will typically rebid the battery as unavailable to generate. This rebid will usually include an assumption as to when the battery may become available again later in the trading day. Some battery operators may rebid to maximum availability when the battery is only partially charged, while others may wait for a higher level of charge before rebidding the battery as fully available. This is because a battery with low charge (e.g. 5%) is just as capable at operating at full generating output as a battery with high charge (e.g. 80%), but the duration of the generation will be much shorter for the low charged battery.

This divergence in how battery operators rebid their batteries as available means that an understanding of the true availability of the battery generating fleet can only be obtained from an understanding of the prevailing state of charge of batteries. A battery fleet that is bid fully available with only 5% charge is very different from a battery fleet that is bid as fully available with 100% charge.

This effect that batteries have on uncertainty in pre-dispatch is currently limited with only a few batteries operating in the NEM. However, this uncertainty could be substantial with a greater take up of batteries, approaching 7GWs by 2030.[76] The publication of aggregate real-time state of charge would be a useful metric for market participants to validate pre-dispatch forecasts and the range of outcomes over the trading day, thereby allowing them to make more informed operational decisions.

4.4 The Commission is interested in stakeholder views on the risks of publishing information on energy availability

While the Commission considers that increasing the information on energy constraints and the state of charge of batteries would assist the provision of reserves in both short and long timeframes as we transition, we recognise that stakeholders held some concerns with respect to how this information would be published. As discussed further below in section 4.4.2, the draft

76 AEMO, 2022, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-isp-infographic.pdf?la=en, figure 1.

rule requires daily energy availability information and battery state of charge information to be aggregated by region so as not to reveal the energy constraints or state of charge of any individual participant.[77]

However, the Commission is interested in stakeholder views on whether there remains the risk of any potential perverse outcomes as a result of this draft rule. This is particularly related to gaming behaviour and whether increased information could lead in some instances to less efficient bidding outcomes or otherwise to facilitate anti-competitive conduct.

4.4.1 The trade-offs of providing greater supply-side information

The Commission recognises that there are trade-offs to increasing market participant information. Currently, more sophisticated participants may already calculate and use extra information, akin to the information noted above, to inform their decision-making. Centrally publishing this information may reduce any information asymmetry, benefiting the overall efficiency of the energy market to allocate reserve capacity. However, there may also be commercial sensitivities that need to be considered.

The Commission considers that there are commercial sensitivities with publishing energy availability which should be mitigated through data aggregation (see section 4.3.1). However, there is also the potential risk of anti-competitive behaviour associated with increased supply-side information transparency. For example, increased information on competitors' state of charge actions may inform participants of their competitors' operational limits, and could be used to signal or predict particular patterns of bidding behaviour, which could lead to anti-competitive or inefficient outcomes (particularly in real-time). In regions were there are a few market participants present, information on energy constraints and battery (state of charge) could increase the risk of collusion. Participants could potentially infer the state of charge levels for other plant in the region and use this information to send signals on when to charge and deploy energy.

There was mixed feedback in response to the directions paper in relation to perverse bidding outcomes. Neoen noted concern that there "may be the potential for this information to be used by other bidders with unintended outcomes (i.e.gaming behaviour)".[78] However, other stakeholders did not consider this risk of anti-competition outcomes to be material.[79] Some submissions also noted that this information is already publicly available through participants websites.

While the AER was in support of the proposed change, it also noted that care needed to be taken such that it doesn't negatively impact on market competition.[80]

4.4.2 We propose to aggregate energy availability information by region only

Energy availability information needs to be aggregated such that information about specific plant can not be determined

There was a strong preference from stakeholders that information published on energy availability, in advance of real-time, should be aggregated such that it is unlikely for participants to ascertain information about specific plant at a DUID level.

It is currently difficult for market participants to determine the state of charge of batteries at a DUID level due to:

77 Draft rule, rule 3.7G(d) and (e).

78 Neoen submission https://www.aemc.gov.au/sites/default/files/2023-09/Neoen.pdf, p. 1.

79 Including submissions to the 2023 directions paper from Energy Australia (p.2); Stanwell (p.3); and AGL (p.1).

80 AER submission, https://www.aemc.gov.au/sites/default/files/2023-09/AER.pdf, p. 2.

- The flexibility and bi-directional nature of batteries, which means that their charge levels can change rapidly
- The fact that change rates are sensitive to a number of factors, including temperature. Changes in weather patterns can make it more difficult to predict the state of charge of a battery at any point in time.

It is also currently difficult to determine fuel reserves at a DUID level for other scheduled plant, such as thermal, hydro and gas. Individual fuel levels (such as coal stockpiles) are not shared publicly, whereas dam levels are monitored by regulating agencies to ensure hydro plant are not in breach of water licensing requirements.

The Commission considers that publishing energy availability information by region does not reveal individual participant information

Stakeholders also raised concerns about the information being too granular because publication of energy constraint information at a high level of granularity (e.g. at the DUID level) could reveal bidding preferences of energy-limited plant to the market. On the other hand, stakeholders agreed with the Commission that publishing this information at a NEM-wide level may not be useful for market participants and may not lead to more efficient market outcomes.

The level of aggregation at which energy availability information is published should therefore strike a balance such that competition risks are minimised, while market efficiency outcomes from information transparency are maximised. Therefore, the draft rule aggregates the energy constraint information by region only, and does not further disaggregate the energy constraint information by technology type.[81]The Commission considers that publishing this information by region and technology type could lead to the identification of an individual market participant in some regions.

Sufficient penetration of batteries in the NEM is required before state of charge information can be published by region

Determining an appropriate level of aggregation is complex, due to the dynamic nature of the NEM and the fact that the generation mix will change significantly during the transition.

There may be some concern that the current number of market participants in respect of batteries is insufficient to ensure that aggregation by region results in appropriate anonymity for individual assets. However, the Commission expects that there will be a sufficient number of battery assets in the future to have an appropriate level of aggregation such that state of charge information at a DUID level is not revealed or otherwise able to be devised where there is regional aggregation.

The Commission wants to have a sufficient amount of battery providers to have an appropriate level of aggregation such that DUID state of charge information is not revealed. Based on our current projections this is likely to occur in or around June 2027. This is supported by the jurisdictional storage targets and research by the Commonwealth Scientific and Industrial Research Organisation (CSIRO), that noted "battery storage systems will see an acceleration in uptake around 2025, based on current trends and the need for cost reductions to become widely available"[82] This research, and the need for a sufficient amount of battery assets prior to publishing this information, forms the basis of our implementation timing discussed below in section 4.5.

81 Draft rule, rules 3.7G(c) and (d).

82 Clean Energy Council, *Clean energy Australia report,* 2023, https://assets.cleanenergycouncil.org.au/documents/Clean-Energy-Australia-Report-2023.pdf, p.44.

4.5 Implementation considerations

Given the dynamic nature of the NEM, it is likely that an appropriate level of aggregation is only possible for some plant type, such as batteries, when more plant of that type becomes operational in the system. The Commission also notes that the IESS Rule will commence in June 2024. To provide time for additional market entry of batteries before publishing this information and enable consistency with other related rule changes, the Commission's draft rules are to commence as follows:

- 1 July 2025: Publishing state of charge information for batteries, at the DUID level, for each trading interval in respect of the previous trading day
- 1 July 2025: Publishing daily energy constraints of other scheduled plant types (e.g. hydro, gas and coal) in advance for the trading day
- 1 July 2025: Require storage participants to submit its maximum storage capacity in their bid and offer validation data.
- 1 July 2027: Publishing state of charge information for batteries close to real time.

This would:

- provide additional time for battery storage to enter the market which should mean that there is an adequate level of aggregation when publishing energy state of charge information by region
- minimise the additional reporting obligations on market participants when AEMO publishes daily energy constraint information to the market
- allow time for AEMO to determine the most appropriate mechanism to use to publish the energy constraint information and state of charge data, and consequently update any internal processes.

5 We consider regional and sub-regional FCAS raises a number of different issues that should be looked at through a dedicated rule change

Box 4: Key points in this chapter

- The changes in the energy market that are leading to greater variability and uncertainty in timeframes of five minutes and longer are also influencing shorter timeframes of less than five minutes. In these shorter timeframes, it is the procurement of FCAS that assists in balancing supply and demand.
- As demand becomes more variable due to the increasing uptake of consumer energy resources, as well as more variable energy sources are connected (such as wind and solar), there may need to be adjustments to support frequency stabilisation in a region following a rapid and unexpected change in VRE output.
- The AEMC has had a substantial work program over the past several years that has reformed the frequency arrangements to be fit for purpose given the changing system. This work program aims to help AEMO to manage the secure operation of the power system in accordance with the technical limits specified in the Frequency Operating Standard (FOS), including the mandatory provision of primary frequency response (PFR) from scheduled and semi-scheduled generators and the introduction of new market ancillary services for faster responding technologies. In addition, the inclusion of incentive payments for PFR also aims to deliver more efficient operation of, and investment in, power system plant.
- In addition, the AEMC introduced the indistinct event framework to help AEMO identify and manage risks due to weather events, such as the risk of rapid reduction in output from multiple, smaller generators in destructive wind conditions. Depending on the nature of the risk, AEMO can take appropriate preventative action.
- One additional suggestion that has come to light in this rule change is that the need to manage frequency due to rapid and unexpected changes in VRE output could potentially be managed in a more cost-effective way by accessing FCAS through regional and sub-regional frameworks.
- In early 2023, Powerlink provided a submission to the Commission's 2021 Operating reserve directions paper, suggesting that regional and sub-regional FCAS procurement could be formalised within the Rules.
- The Commission sought wider stakeholder feedback on this suggestion in its 2023 directions paper.
- We received a diverse range of feedback, with particular concerns that changes to the FCAS frameworks at a regional/sub-regional level might impact the global FCAS market, with questions around market power and cost-recovery.
- Some stakeholders also considered that given the materiality of this change, it is not considered an incremental improvement and should therefore, if implemented, be assessed through a dedicated rule change to avoid any perverse or unintended outcomes.
- The Commission has investigated the rules around regional and sub-regional FCAS and considers:

- the Rules currently enable AEMO to procure FCAS at a regional level and do not limit this to any specific type of event
- the Rules are not clear on whether the provisions for regional FCAS procurement extend to a sub-regional level.

- In response to stakeholder views and further analysis, we consider regional/sub-regional FCAS raises a number of different issues to those considered here and so would be best looked at through a separate rule change. We are therefore not proposing to amend the Rules in this rule change to specify when regional or sub-regional FCAS should be procured. If a rule change was submitted on these issues, then we would consider it at the time.
- We also note that stakeholders raised a number of alternatives to regional and sub-regional FCAS procurement, including implementing tie-line-bias control, or accessing existing frameworks including the network support and control ancillary services and remedial access schemes that would also need to be explored in that context.

This chapter covers the Commission's response to stakeholder feedback and further analysis on regional and sub-regional FCAS procurement, including:

- Section 5.1 — Large-scale renewable generation infrastructure introduces new challenges for system security
- Section 5.2 — We sought wider stakeholder feedback on this incremental improvement
- Section 5.3 — The Commission is proposing not to amend the Rules in this rule change to specify when FCAS should be procured either regionally or sub-regionally
- Section 5.4 — There are alternatives to regional and sub-regional FCAS procurement that may also address similar issues. We consider that such matters should be considered holistically through a separate rule change process.

As discussed further below, although the Commission is not proposing to amend the Rules to specify how FCAS should be procured regionally or sub-regionally through this rule change process, we are providing guidance following additional analysis in relation to regional FCAS procurement (see section 5.3.2).

5.1 Large-scale renewable generation infrastructure introduces new challenges for system security

As demand becomes more variable due to the increasing uptake of consumer energy resources, as well as more variable energy sources are connected (such as wind and solar), there may need to be adjustments to support frequency stabilisation in a region following a rapid and unexpected change in VRE output.

AEMO is required to maintain the power system such that it will operate in a secure operating state.[83] AEMO monitors a number of elements in the power system including frequency, voltage, current flow and plant status to ensure it is in a secure operating state.[84] Day-to-day operational risks, such as the loss of a large generating unit or single transmission line, are known as "credible contingencies". Under the Rules, AEMO, must identify and take pre-emptive action to prepare for these types of risks, for example by purchasing additional frequency control services.[85]

83 Clause 4.2.4 of the NER.

84 Clause 4.2.2 of the NER.

The generation output of future renewable energy zone (REZ) developments is likely to be larger than the largest contingencies operating within the NEM today.[86] This could therefore introduce new challenges in maintaining the power system in a secure operating state.

5.1.1 The AEMC has implemented a number of frequency reforms to support power system operation as we transition

The AEMC has had a substantial work program over the past several years that has reformed the frequency arrangements to be fit for purpose given the changing system.

This work program (see below) aims to help AEMO to manage the secure operation of the power system in accordance with the technical limits specified in the Frequency Operating Standard (FOS). In addition, the inclusion of incentive payments which will commence on 8 June 2025 aim to deliver more efficient operation of- and investment in- power system plant. This will occur by encouraging innovation and deployment of new capabilities that would deliver lower overall frequency control costs for consumers over the longer-term.

The Commission's frequency reform work program includes:

- *Fast frequency response market ancillary service rule* 2020[87] which introduced two new market ancillary services for faster responding technologies to help control system frequency.
- *Mandatory primary frequency response rule* 2020[88] which sought to promote power system security by introducing a mandatory obligation for scheduled and semi-scheduled generators to provide PFR.
- *Integrating Energy Storage Systems into the NEM rule* 2021[89] which introduced the new Integrated Resource Provider registration category to make it easier for energy storage systems to participate in the NEM. Under the IESS rule, standalone storage capable of linearly and smoothly transitioning from charging to discharging must be classified as a:
  - scheduled bidirectional unit if its capacity is 5MW and above
  - non-scheduled bidirectional unit, if its capacity is under 5MW.
- *Primary frequency response incentive arrangements rule* 2022[90] which established an enduring framework for the long-term provision of PFR in the NEM by confirming the mandatory obligations and introducing frequency performance payments.
- *Reliability Panel review of the frequency operating standard* 2022[91] which revised the FOS to adapt to the changing nature of the power system as thermal generators are increasingly displaced by inverter based resources. The revised FOS confirmed the settings for normal operation, including the primary frequency control band (PFCB) that relates to the sensitivity for mandatory primary frequency response provided by scheduled and semi-scheduled generators.

85 A power system may be identified as unstable immediately following a Credible Contingency Event. AEMO has 30 minutes to intervene and return the power system to a secure operating state.

86 The largest contingency is currently based on the loss of Kogan Creek at ~750MW, and as high as 763MW depending on Kogan Creek's output. See section 3.6 here https://www.aemc.gov.au/sites/default/files/2021-04/FFR_Implementation.pdf

87 See: https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service

88 See: https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

89 See: https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

90 See: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

91 See: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

5.1.2 We also introduced an additional framework to help AEMO better prepare for and manage indistinct risks

As the power system decentralises, the risk profile of the system is changing. Today, there are an increased number of smaller generators dispersed throughout the system, with variable output depending on the amount of wind and sunshine. This means there is increased uncertainty about the amount of generation that will be available at any one time.

To help AEMO better manage this increased uncertainty in generator availability during periods of normal operation, the AEMC introduced an additional framework to manage new types of "indistinct" risks.[92] The additional framework sets out how AEMO is able to identify risks due to weather events, such as the risk of rapid reduction in output from multiple, smaller generators in destructive wind conditions. Depending on the nature of the risk, AEMO is also able to take appropriate preventative action.

5.1.3 Powerlink's submission noted the benefits of prescribing regional and sub-regional FCAS procurement

Under current arrangements, FCAS is normally procured globally in the NEM. This is referred to as the 'global market ancillary service requirement'. That is; the service can be sourced from any region. However, the Rules also permit AEMO to procure FCAS from one or more nominated regions.[93] This is referred to as a 'local market ancillary service requirement'. AEMO's past practice has been to procure FCAS on a regional basis at times when the interconnector between two regions is at a credible risk of separation, and in circumstances when separation has occurred and the region is operating as an island.

In early 2023, Powerlink provided a submission to the Commission's 2021 *Operating reserve directions* paper, suggesting that regional and sub-regional FCAS procurement be formalised within the Rules.[94]

Powerlink proposed to amend the NER and relevant subordinate instruments, to develop a regional and sub-regional FCAS framework to allow for the potential for greater raise FCAS procurement.

Powerlink's proposal would see AEMO procure FCAS on a regional basis, or limit the amount of FCAS procured from a single region to increase the amount of FCAS procured in other regions. A higher amount of raise FCAS enabled would mean there would be higher levels of 'headroom' in the system. Powerlink considered that :

- this could increase the potential generation capacity in REZ developments and enable increased utilisation of the network connection.
- more localised arrangements for FCAS would value the trade-off between higher raise FCAS and the cost savings from the development of more scale-efficient connection infrastructure. Such requirements could be dynamic, trading off the cost of FCAS and savings in the energy market to allow for greater credible generation contingency sizes.

Powerlink noted that a less complex and possibly transitional arrangement may be to reassess the maximum credible contingency size on a regional or sub-regional basis periodically until a full market co-optimisation could be implemented.

92 See: https://www.aemc.gov.au/rule-changes/enhancing-operational-resilience-relation-indistinct-events

93 See clause 3.8.1(e2) of the NER.

94 For more information see https://www.aemc.gov.au/sites/default/files/2023-09/Powerlink.pdf

5.2 We sought wider stakeholder feedback on this incremental improvement

The Commission sought wider stakeholder feedback on the merits of prescribing how FCAS should be procured regionally and/or sub-regionally in the Rules in its second directions paper.[95]

We received a diverse range of feedback. Some stakeholders queried whether a rule change was needed at all given the rules already permit AEMO to procure FCAS regionally.[96] Snowy Hydro suggested "there is no need for further Commission action beyond a clear signal to AEMO that it should exercise this capability".[97]

Stakeholders also had a range of views in the event that the Commission determines to include greater guidance in the Rules on FCAS procurement.

- Several stakeholders highlighted a need for the Commission to further investigate how the risk of market power might be mitigated. Stakeholder feedback on the implementation of sub-regional FCAS procurement was more mixed than regional FCAS procurement and suggested the Commission would need to conduct further analysis to detail how this may work.
- Tesla noted it "would like more information to be provided from AEMO regarding how [regional FCAS procurement] would be managed".[98]
- Shell noted a need to understand how payment arrangements may work, noting "any changes to how FCAS is procured is also likely to require consideration of how FCAS is priced".[99] The current payment arrangements for global FCAS will need to be investigated to understand whether it can be extended to regional and sub-regional FCAS procurement. CS Energy noted "sub-regional FCAS procurement is worth consideration, however it adds complications to the "who pays" question given the traditional causer-pays approach would not apply."[100] Energy Australia supported this view, noting "if AEMO intends to commence regional procurement (or sub-regional) further clarification on the methodology for its decision/application, process for cost-recovery & limitations on the frequency in which a global FCAS service can be reduced to a regional service [is required]".[101]

As AEMO noted in its submission, REZ development could lead to large volumes of energy concentrated on a single transmission line.[102] In a contingency event, procurement of FCAS globally could trigger voltage or stability issues associated with changes to inter or intra-regional power flows.[103]

Expanding the framework under which regional FCAS operates to respond to the contingency risks that arise from REZ implementation, and potentially extending it to include sub-regional FCAS, is likely to be quite complex. In its submission, AEMO noted a number of elements to consider including "the relationship between 5-minute dispatch, available reserves, FCAS, the way the REZ generation is expected to "runback", and the applicable short-term rating of the circuit needs much more investigation."[104] Further, AEMO noted that network planners are presently considering how

95 For more information see https://www.aemc.gov.au/sites/default/files/2023-08/directions_paper.

96 This includes submissions to the 2023 directions paper, Snowy Hydro (p. 3) and Alinta Energy (p. 2).

97 Snowy Hydro submission https://www.aemc.gov.au/sites/default/files/2023-09/Snowy%20Hydro.pdf, p.3.

98 Tesla submission, https://www.aemc.gov.au/sites/default/files/2023-09/Tesla.pdf, p.1.

99 Shell Energy submission, https://www.aemc.gov.au/sites/default/files/2023-09/Shell%20Energy%20.pdf, p.3.

100 CS Energy submission, https://www.aemc.gov.au/sites/default/files/2023-09/CS%20Energy.pdf, p.4.

101 Energy Australia, https://www.aemc.gov.au/sites/default/files/2023-09/Energy%20Australia.pdf, p.3.

102 AEMO submission, https://www.aemc.gov.au/sites/default/files/2023-09/AEMO.pdf, p.4.

103 AEMO submission, https://www.aemc.gov.au/sites/default/files/2023-09/AEMO.pdf, p.4.

104 AEMO submission, https://www.aemc.gov.au/sites/default/files/2023-09/AEMO.pdf, p.4.

to size connections for REZ infrastructure. This includes consideration of additional infrastructure to support REZ connections such as double-circuit transmission.[105]

The AER suggested tie-line-bias control as an alternative to regional and sub-regional FCAS procurement. Tie-line-bias control "monitors the transmission flows rather than frequency".[106] See section 5.4 for more information on this proposal.

5.3 The Commission is not proposing to amend the Rules to specify when FCAS should be procured regionally or sub-regionally through this rule change process

In light of stakeholder feedback, the Commission is proposing not to pursue any amendments to the Rules in this rule change to specify when or how FCAS should be procured at a regional or sub-regional level. The Commission considers that AEMO is currently provided with sufficient flexibility in the Rules to determine the most appropriate form of FCAS procurement to ensure the secure operation of the power system.

The concept of regional/sub-regional FCAS raises a number of different issues that would be better looked at through a separate rule change process. If a rule change was submitted on these issues, then we would consider it at the time.

In the interim, the Commission has provided guidance on how the Rules currently permit FCAS at a regional level (see section 5.3.2). There are additional complexities in relation to sub-regional FCAS procurement under the current Rules which are discussed further in section 5.3.3.

5.3.1 Tie-line-bias control

The Commission has also further investigated the option of tie-line-bias control as raised by the AER in its submission. Under the AER's proposed arrangement, the flows on an interconnector (or other key transmission pathway) are monitored and adjusted through regional procurement of regulating FCAS to balance unexpected changes in demand across adjacent regions. The AER suggested tie-line-bias control as an alternative solution to individual regional and sub-regional FCAS procurement.[107]

Following our internal analysis, it is likely that the tie-line-bias control would be complex to implement and require a thorough investigation to understand how it may impact the existing global FCAS frameworks. It would require regional or sub-regional regulation services to enable effective control of inter-regional circuits via automatic generation control (AGC). The Rules do not currently limit AEMO from procuring regulating FCAS on a regional basis and the use of tie-line bias control. The Commission is therefore not proposing to assess it further through this rule change process.

5.3.2 The Commission considers the market operator can procure FCAS at a regional level under the current Rules

AEMO acquires market ancillary services (MAS) (this is commonly referred as "FCAS") as part of the spot market, through central dispatch.[108] As part of central dispatch, AEMO is required to determine the quantity of MAS to be enabled.[109] Specifically, AEMO is required to determine:

105 AEMO submission, https://www.aemc.gov.au/sites/default/files/2023-09/AEMO.pdf, p.3.

106 AER submission, https://www.aemc.gov.au/sites/default/files/2023-09/AER.pdf, p.2.

107 AER submission, https://www.aemc.gov.au/sites/default/files/2023-09/AER.pdf, pp. 2-3.

108 Clause 3.2.2(c1) and 3.8.1 of the NER.

109 Clause 3.8.1 of the NER.

- A global market ancillary service requirement which is the required quantity of each MAS that may be sourced from any region.[110]
- A local market ancillary service requirement which is any required quantity of MAS which must only be sourced from one or more nominated regions.[111]

The Rules set out certain requirements for how AEMO can procure MAS. Some of these requirements, and their relevant clauses, are shown in Table 5.1. However, while the requirements highlighted in Table 5.1 provide a framework for the procurement of MAS more generally, these provisions do not prescribe or preclude the use of regionally procured MAS. For example, the Rules do not specify when, or under what conditions, AEMO should procure a global or local market ancillary service. Under the Rules, AEMO is not limited to using MAS during instances where two or more regions are at a credible risk of separation or have already separated.

AEMO's typical practice is to procure FCAS on a global basis, with FCAS procured regionally under certain operating conditions, including when there is a credible risk of separation and in cases where a region is operating as an island. The Rules do not place conditions on the regional procurement of FCAS and AEMO is free to procure FCAS on a regional basis at any time in order to provide sufficient flexibility to maintain the power system in a secure state. Therefore, AEMO is not limited to using MAS during instances where two or more regions are at a credible risk of separation or have already separated.

Table 5.1: MAS requirements

Clause	Description
Clause 3.1.4(a)(6)	MAS should be acquired through competitive market arrangements and determined on a dynamic basis as far as practicable.
Clause 3.2.2 and 3.4.1	MAS are acquired through the spot market.
Clause 3.3.17	MAS prices are subject to the same constraints as spot prices, e.g. MPC.
Clause 3.8.1(b)	The same linear programming constraints that apply to spot market trading through central dispatch apply to MAS.
Clause 3.8.7A	Details the requirements for MAS offers.
Clause 3.8.11(a)	AEMO must determine the quantity and nature of MAS which have been provided in accordance with AEMO power system security responsibilities (clause 4.3.1), are required to be managed in conjunction with dispatch and may impose constraints on dispatch.
Clause 3.9.1(2A) and 3.9.2A	The prices for MAS are determined by central dispatch, including the marginal price for meeting a global MAS requirement and each local MAS requirement.

Source: NER

5.3.3 The Rules are more complex in relation to sub-regional FCAS procurement

We have also investigated whether sub-regional FCAS procurement is permitted under the Rules. Currently, the Rules do not explicitly discuss the procurement of MAS at a sub-regional level.

110 Defined in clause 3.8.1(e2)(1).

111 Defined in clause 3.8.1(e2)(2).

Because of this absence, the Commission is unable to provide formal guidance on whether sub-regional FCAS is either permitted or precluded under the existing Rules.

At this stage, we consider that further investigation, and possible amendments to the Rules, are required to allow AEMO to procure FCAS at a sub-regional level. This may require the inclusion of an express reference to sub-regional requirements (or requirements within a region) in the NER, considerations around market power risks, and potential updates to NEMDE to introduce constraints that can be configured to enable procurement of FCAS at a sub-regional level.

The Commission is not proposing to investigate these issues through this current rule change process as discussed above.

5.4 There are alternatives to regional and sub-regional FCAS procurement that may also address similar issues

The Commission notes that there are a number of existing frameworks that may enable more cost-effective outcomes in the management of large contingency events, which could also be considered in any future rule change on this issue.

This includes the network support and control ancillary services (NSCAS) and remedial action schemes (RAS) frameworks.

AEMO and TNSPs can procure contracts through the NSCAS framework to:

- maintain power system security and reliability,[112] or
- maintain or increase the power transfer capability of the transmission network.[113]

A RAS is an automated scheme that, following a contingency on the power system, automatically takes action to prevent adverse outcomes such as cascading outages. While a RAS most commonly operates following contingency events; however, some RASs are used to manage changes in power system quantities during system normal conditions that could otherwise result in exceedance of operating standards or damage assets.[114]

Examples of RASs include:

- Run back schemes: where a generator 'runs back' in response to an event or based on local monitoring. Examples including run back subject to wind availability where less than firm capacity was offered.
- Wide Area Monitoring Protection and Control/System Integrity Protection Schemes: these schemes use high speed monitoring of the network status and automatically take protective action. Protective action can involve a mix of battery energy storage systems (BESS), generation and demand response.

These frameworks allow for bespoke requirements and alignment of cost recovery. The contracts entered into for these arrangements can:

- allow for a specific event or set of events, including catering to single and multiple contingencies
- dictate the specific response and rate of response required

112 See clause 3.11.6(a)(1) of the NER.

113 See clause 3.11.6(a)(2) of the NER.

114 For more information on the types of RASs available see https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/final-remedial-action-scheme-guidelines.pdf

- ensure the location of the response is electrically positioned to achieve results with lower risk of unintended consequences.

These frameworks could be a simpler or interim option than regional/sub-regional FCAS procurement. It may provide more flexibiltiy with cost recovery, as TNSPs can appropriately allocate these costs to either connecting generators or cover costs via the RIT-T process. This could align costs with causers and beneficiaries and enables recovery of costs without affecting the wider market.

While these frameworks exist within the current arrangements, the Commission is not providing advice as to the relative benefits or costs of entering into either a RAS or NSCAS contract. We consider that participants should consider whether these options are appropriate for their individual needs and circumstances. Such matters would be considered more fulsomely as part of as any future rule change on this issue.

A Summary of other issues raised in submissions

This section outlines stakeholder feedback raised through submissions to the directions paper that has not been discussed in the relevant sections in this draft determination.

Stakeholder feedback on the previous consultation papers are found in Appendix B of the 2023 Directions Paper.

Table A.1: Summary of other issues raised in submissions

Stakeholder	Issue	Response
Shell Energy CS Energy EUAA	**Operational forecast accuracy transparency** Several stakeholders proposed that the AEMC should investigate how the accuracy of lack of reserve (LOR) forecasts is communicated through a regular report. This would determine whether a genuine reserve shortfall occurred by comparing the forecast and actual LOR declarations with real-time 5-minute dispatch outcomes. Stakeholders noted that the rise in LORs in recent years may be due to inaccurate forecasts, rather than genuine reliability shortfalls. Stakeholders also noted a risk that increased LORs may dilute their effectiveness in signalling to the market when there is a genuine reliability need.	The Commission appreciates stakeholder concern about an increase in LORs and the need for accurate operational forecasts. The Commission understands that AEMO is currently progressing with a program of work dedicated to improving operational forecasts. In addition, AEMO currently publishes a range of information to the industry, particularly around RERT activation and LOR declarations. Detailed data on operational demand and forecasts are also provided via AEMO's NEMWeb. Nevertheless, we appreciate stakeholder concerns that more transparency is required. We note that the Rules do not preclude AEMO from providing additional information to the market on its operational forecasts and the declaration of LORs. We therefore encourage AEMO to engage with the industry on the information that is currently missing from its publications with regard to LORs,

Stakeholder	Issue	Response
		to support industry-wide learning and understanding of reliability shortfalls and operational forecasts.
Snowy Hydro AEC AGL Tesla	**Market settings** These stakeholders noted that investment signals are currently constrained by the market settings, including the Market Price Cap (MPC), the Cumulative Price Threshold (CPT), and the Administered Price Cap (APC). Stakeholders noted that it remains pertinent to focus on the role these settings play in delivering reliability outcomes and providing appropriate investment signals.	We recognise the need for appropriate market settings to provide the necessary reliability outcomes. However, this is outside of the scope of this rule change and has been considered through a separate rule change process. On 7 December 2023, the AEMC made a more preferable final rule to amend the market settings in the NEM for the period 1 July 2025 to 30 June 2028. The more preferable final rule: • sets the MPC and CPT at the level recommended by the Reliability Panel (Panel) in the 2022 Reliability Standard and Settings Review (RSS Review) adjusted for inflation. • sets the APC at $600/MWh, which is different from the Panel's recommendation of $500/MWh but consistent with its current value.
CS Energy	**Ramping rates in the FUM** CS Energy noted that the existing reserve assessment processes incorporate a measure of uncertainty via the Forecast Uncertainty Measure (FUM), but they do not incorporate a measurement of the system ramping requirement or available system flexibility to meet this	The Commission is not proposing to pursue this option as part of this rule change. Following further analysis and stakeholder feedback, we consider that the wider market benefits may be limited. We consider that the concerns of information asymmetry could be mitigated through improving

Stakeholder	Issue	Response
	requirement. CS Energy noted that AEMO and the AEMC should determine whether these can be modified to include ramping events and clearly communicated to the market or whether a separate operational metric is required on which the volume of procured reserves is based.	transparency of energy limits, as discussed in chapter 4. We also note that AEMO is currently pursuing changes to the FUM as part of the ST PASA replacement project.
CS Energy	**LOR for FCAS** CS Energy proposed the development of a similar “lack of” reserve framework for FCAS to provide critical market signals for the co-optimisation of reserves for energy and FCAS requirements.	The Commission is not proposing to pursue this option as part of this rule change. Following further internal analysis and stakeholder feedback, we consider that the wider market benefits may be limited and is outweighed by the potential cost and complexity of implementing this option.

B Rule making process and consultation to date

A standard rule change request includes the following stages:

- a proponent submits a rule change request
- the Commission initiates the rule change process by publishing a consultation paper and seeking stakeholder feedback
- stakeholders lodge submissions on the consultation paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if relevant)
  - stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a final determination and final rule (if relevant).

You can find more information on the rule change process on our website.[115]

B.1 The proponent proposed a rule to implement an explicit model to value reserves in the operational timeframe

The *Enhancing reserve information* rule change was initiated from two rule change requests from Iberdrola Australia (previously Infigen Energy) and Delta Electricity.

The rule change request from Iberdrola Australia seeks to amend the NER to introduce a dynamic 'operating reserve market' to operate alongside the existing energy and FCAS markets. The proposed market comprises a dispatchable, raise-only service procured similarly to contingency FCAS services in real-time and co-optimised with the other energy market services. The request proposes that this market would procure reserves 30 minutes ahead of time (with a 15-minute call time) to align with the requirement to return the system to a secure operating state within 30 minutes.

The rule change request from Delta Electricity seeks to amend the NER to introduce 30-minute raise and lower "ramping" FCAS services using the existing framework for FCAS market design. Delta suggests these ramping services would address the price volatility that exists when dispatchable generators ramp through their energy offer stacks in response to predictable, daily, high rates of change from solar ramping up and down.

Delta Electricity proposes this service:

- be procured from dispatchable in-service generators
- reflect a similar dispatch and settlement process to existing FCAS raise and lower services, but with provision for generators to offer (perhaps three) incremental rates of change at different prices, and
- participants in this service would not be prevented from bidding into the other FCAS markets as long as they can comply with the associated obligations of each.

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

B.2 The proposal addressed variability and uncertainty as more VRE enters the system

The NEM's physical reliability risk profile is undergoing a shift as it transitions from being a capacity-limited thermal power system to being a weather-driven, energy-limited (both renewables and thermal fuel) power system with declining thermal generation availability.

The changing risk profile gives rise to an increase in variability and uncertainty in the power system, particularly as more VRE generation is adopted. These issues in the power system have been highlighted in the rule change requests made by Iberdrola and Delta, as well as by AEMO in its technical advice.

B.2.1 Iberdrola suggests current arrangements may not be sufficient to meet the higher risk and frequency of contingency events

In its rule change request, Iberdrola considers that there is a higher risk of contingency events in the future due to more frequent extreme weather events, with such contingency events traditionally not classified as credible.[116] It also considers that there will be an increasingly wide range of new and unknown modes of failure ('unknown unknowns') that are difficult to predict and of which we have limited understanding. In addition, Iberdrola highlights that there are decreasing amounts of operating reserves in the system due to transitioning generation stock and a lack of incentives for new investment that has this capability.[117]

B.2.2 Delta highlighted the growing problem of sustained ramping requirements as a result of increased VRE penetration in the NEM

In its rule change request, Delta contends that there is an imminent and growing problem in the sustained ramping requirements imposed on the NEM's fleet of scheduled generators to accommodate the total solar daily generation profile. Delta states that: [118]

> 'in effect, scheduled fully dispatchable generators need to provide the inverse of the solar profile, as well as dealing with:
>
> - wind generation variability
> - coincident changes in the pattern of underlying consumption of electricity
> - any contingency events such as load shedding, generator trips or interconnector failure.'

The key problem identified by Delta is that the predictable, daily, high rates of change from solar can lead to increased price volatility, leading to greater variability and uncertainty and therefore potential AEMO interventions. Delta acknowledges that price volatility is not an inherently adverse outcome and may provide incentives for available capacity to respond to the growing ramping need. However, Delta suggests that there may be a more sustainable approach.

B.3 The process to date

On 19 March 2020 and 4 June 2020 respectively, the Commission received a rule change request from Iberdrola Australia and Delta Electricity.

116 Iberdrola, 2020, Operating reserves and fast frequency response rule change, https://www.aemc.gov.au/sites/default/files/2020-03/ERC0295%20Rule%20change%20request.pdf, p. 6.

117 Iberdrola, 2020, Operating reserves and fast frequency response rule change, https://www.aemc.gov.au/sites/default/files/2020-03/ERC0295%20Rule%20change%20request.pdf, p. 6.

118 Delta Electricity, 2020, Introduction of ramping services, https://www.aemc.gov.au/sites/default/files/2020-06/ERC0307%20Rule%20change%20request%20pending.pdf, p. 6.

A consultation paper identifying specific issues for consultation was also published on 2 July 2020, along with five other rule change requests.[119] Of the stakeholders who responded to the consultation paper, 25 commented on matters relating to the Iberdrola and Delta rule change request. Stakeholders generally agreed that reserves are critical to ensuring the security and reliability of the power system as it transitions. There were differing views, however, on whether an explicit new reserve service is required, how such a service should operate, and the specific power system conditions it should address. Stakeholders also held a range of views on the economic benefits of implementing a new reserve service. Some considered there are benefits to addressing the increasing uncertaint on the power system, while others considered that current arrangements are sufficient to address this issue. Further details on this consultation are found in Appendix B of the 2023 directions paper.

The AEMC published a directions paper on the reserve services rule changes on 5 January 2021.[120] The paper invited stakeholder feedback on:

- the power system need for reserves and the materiality of the need for a new operating or ramping service as the power system transforms.
- options to address variability and uncertainty on the power system, including:
  - incremental improvements to current arrangements
  - four new reserve service market options.

Submissions closed on 11 February 2021. The Commission received a total of 23 submissions.

Three key themes emerged from the responses:[121]

1. Stakeholders were divided on the need for a new reserve service is, and whether the need is material enough to implement a new service.
2. There was significant support for incremental improvements to current arrangements.
3. There is no clear consensus on which option is best, but some themes emerged.

The Commission released a second directions paper in August 2023. We received 18 submissions in response, with stakeholders noting largely:

- support for not proceeding with an operating reserve market
- support for publishing energy limits in the operational timeframe, noting the need for aggregation to ensure no commercially sensitive information is published
- a recognition of the benefits of regional and sub-regional FCAS procurement, but some concern on how this would impact the global FCAS market
- some additional incremental improvement the AEMC should consider in absence of an operating reserve market, particularly focused on operational forecasting.

This is discussed further in appendix A and throughout the main body of this paper.

119 See https://www.aemc.gov.au/sites/default/files/2020-07/System services rule changes paper.pdf

120 AEMC, Directions paper reserve services in the national electricity market, 2021, https://www.aemc.gov.au/sites/default/files/Reserve services directions paper.pdf

121 Further details on these responses are outlined in Appendix B of the 2023 directions paper.

C Regulatory impact analysis

The Commission has undertaken a regulatory impact analysis to make its draft determination.

C.1 Our regulatory impact analysis methodology

We considered a range of policy options

The Commission compared a range of viable policy options that are within our statutory powers. The Commission analysed these options: the rule proposed in the rule change request; a business-as-usual scenario where we do not make a rule; and a more preferable rule focused on publishing energy limits in the operational timeframe. These options are described in chapter 2.

We identified who would be affected and assessed the benefits and costs of each policy option

The Commission's regulatory impact analysis for this rule change used qualitative methodologies. It involved identifying the stakeholders impacted and assessing the benefits and costs of policy options. The depth of analysis was commensurate with the potential impacts. In this case, we used qualitative assessment techniques. The Commission focused on the types of impacts within the scope of the NEO.

Table C.1 summarises the regulatory impact analysis the Commission undertook for this rule change. Based on this regulatory impact analysis, the Commission evaluated the primary potential costs and benefits of policy options against the assessment criteria. The Commission's determination considered the benefits of the options minus the costs.

A discussion on why the Commission chose the

Table C.1: Regulatory impact analysis methodology for draft rule

Assessment criteria	Primary costs Low, medium or high –	Primary benefits Low, medium or high –	Stakeholders affected	Methodology QL = qualitative
Safety, security and reliability	Procuring more reserve services (L)	Promote reliability outcomes (L)	All	• QL: stakeholder feedback on the reliability outcomes of increasing energy-limit information to market participants
Emissions reduction	Nil	May promote lower emission technologies to enter the system (L)	All	• QL: assessment of options between an operating reserve market and existing market arrangements
Principles of market efficiency	Place real-time risks on participants to provide reserves (H)	Manage financial risks for those who are best-placed to manage them (H)	• All electricity customers • All generators	• QL: assessment of options between an operating reserve market and existing market arrangements • QL: stakeholder feedback on the directions paper
Implementation considerations	System upgrades (L)	Minimal implementation costs (H)	• Market participants that must comply with new obligations • AEMO	• QL: AEMO advice on costs of system changes • QL: stakeholder advice that this information is already provided to AEMO through existing channels
Principles of good regulatory practice	Nil	Adapt to broader reforms Assist market participants in decision-making	All	• QL: assessment of broader reforms, particularly the *Integrating price responsive resources* rule change • QL: stakeholder advice that increasing information on energy limits would assist participants in making efficient bids

D Legal requirements to make a rule

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

D.1 Draft rule determination and draft rule

In accordance with section 99 of the NEL, the Commission has made this more preferable draft rule determination in relation to the rule proposed by Iberdrola Australia and Delta Australia.

The Commission's reasons for making this draft rule determination are set out in chapter 2.

A copy of the more preferable draft rule is attached to and published with this draft determination in chapter 4.

D.2 Power to make the rule

The Commission is satisfied that the more preferable draft rule falls within the subject matter about which the Commission may make rules.

The more preferable draft rule falls within section 34 of the NEL as it relates to the operation of the national electricity system for the purposes of the safety, security and reliability of that system under section 34(1)(a)(ii) and the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system under section 34(1)(a)(iii).

D.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the draft rule
- the rule change request
- submissions received during first round consultation
- the Commission's analysis as to the ways in which the draft rule will or is likely to contribute to the achievement of the NEO
- the application of the draft rule to the Northern Territory.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[122]

D.4 Making electricity rules in the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[123] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

The more preferable draft rule does not relate to parts of the NER that apply in the Northern Territory. As such, the Commission has not considered Northern Territory application issues.

122 Under s. 33 of the NEL and s. 73 of the NGL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. In December 2013, it became known as the Council of Australian Government (COAG) Energy Council. In May 2020, the Energy National Cabinet Reform Committee and the Energy Ministers' Meeting were established to replace the former COAG Energy Council

123 These regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations 2016

D.5 Civil penalty provisions and conduct provisions

The Commission cannot create new civil penalty provisions or conduct provisions. However, it may recommend to the Energy Ministers' Meeting that new or existing provisions of the NER be classified as civil penalty provisions or conduct provisions.

The more preferable draft rule does not amend any clauses that are currently classified as civil penalty provisions or conduct provisions under the National Electricity (South Australia) Regulations.

The Commission does not propose to recommend to the Energy Ministers' Meeting that any of the proposed amendments made by the more preferable draft rule be classified as civil penalty provisions or conduct provisions.

D.6 Review of operation of the rule

The more preferable draft rule does not require the Commission to conduct a formal review of the operation of the rule. The Commission may however self-initiate a review of the operation of the rule at any time if it considers such a review would be appropriate, pursuant to section 45 of the NEL.

Abbreviations and defined terms

5MS	Five-minute settlement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered price cap
Commission	See AEMC
CER	Consumer energy resources
CIS	Capacity investment scheme
CPT	Cumulative price threshold
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DUID	Dispatch unit identifier
FCAS	Frequency control ancillary services
FOS	Frequency operating standard
FUM	Forecast uncertainty measure
IESS	Integrating energy storage systems
ISP	Integrated system plan
MAS	Market ancillary service
MPC	Market price cap
NEL	National Electricity Law
NEM	National electricity market
NEO	National Electricity Objective
NER	National Electricity Rules
NSCAS	Network support and control ancillary service
PASA	Projected assessment of system adequacy
Proponent	The individual / organisation who submitted the rule change request to the Commission
PFCB	Primary frequency control band
PFR	Primary frequency response
RAS	Remedial action scheme
REZ	Renewable energy zone
SCADA	Supervisory control and data acquisition
VPP	Virtual power plant
VRE	Variable renewable energy