Australian Energy Market Commission

AEMC
Australian Energy Market Commission

RULE

Consultation paper

National Electricity Amendment (Optimising contingency size in dispatch and Allocating FCAS contingency costs) Rule

Proponents
Grids Energy Pty Ltd

20 November 2025

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Reference: ERC0359, ERC0360

About the AEMC

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

Acknowledgement of Country

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

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Summary

1 This consultation paper invites stakeholder feedback on two rule-change requests submitted by Grids Energy Pty Ltd (proponent). These requests relate to the contingency frequency control ancillary services (FCAS) arrangements in the NEM, and aim to optimise contingency size in dispatch and implement the 'runway' method for allocating contingency FCAS costs

2 The proponent submitted these two rule change requests as a package. This paper consults on both proposals due to their shared subject matter and common objective of enhancing the efficiency of the NEM's contingency FCAS frameworks. Following consultation, the AEMC may decide to consolidate the two rule change requests. The proposals are:

- **ERC0359 - Optimising contingency size in dispatch:** The proponent proposes requiring AEMO to co-optimise the size of the largest credible contingency in dispatch. For more information, see: https://www.aemc.gov.au/rule-changes/optimising-contingency-size-dispatch
- **ERC0360 - Allocating contingency FCAS costs:** The proponent proposes recovering contingency FCAS costs using a 'runway cost allocation' approach. For more information, see: https://www.aemc.gov.au/rule-changes/allocating-contingency-fcas-costs

3 This consultation paper addresses each rule change separately as well as in terms of their interactions with each other and the contingency FCAS framework.

4 Contingency FCAS maintains power system frequency stability following disturbances, such as the unplanned loss of a generator, load, or network element, known as contingency events. These services respond rapidly to correct the imbalance in active power caused by such events, arresting frequency deviations and restoring system frequency to approximately 50 Hz.

5 The Australian Energy Market Operator (AEMO) enables the necessary volumes of contingency FCAS to address the impact of the largest credible contingency arising given wholesale energy market dispatch. AEMO updates these requirements every five minutes during dispatch and minimises associated costs based on participant FCAS offers.

6 Contingency FCAS costs and prices in the NEM typically remain low but can rise sharply under certain conditions, such as when an interconnector between NEM regions trips or when the risk of a trip becomes credible. These scenarios require FCAS procurement on both sides of the affected interconnector. Prices and costs may increase significantly if FCAS capability is scarce in a region under these conditions.

7 This rule change relates to frequency control services in the NEM. The AEMC has had an active frequency control reform program since 2017, which included implementing mandatory primary frequency response, incentives for primary frequency response and arrangements for fast frequency response. This rule change request could build on these reforms. While contingency size optimisation and runway cost allocation were considered in the 2017 frequency control frameworks review, 2022 review of the frequency operating standard, and the 2024 enhancing reserve information (formerly operating reserves) rule changes, consideration through these processes didn't lead to proposals for changes to the NER. This will be the first occasion on which the AEMC will consider specific rule changes to address contingency size optimisation and runway pricing.

The proponent has proposed changes to enhance the efficiency of the contingency FCAS arrangements in the NEM

8 The proponent considers its two rule changes work together as a package, as contingency size

optimisation and runway pricing act in a complementary manner.

Optimising contingency size in dispatch

9 The NEM dispatch engine (NEMDE) operates to maximise the value of trade by dispatching generators with the lowest bids across the energy and FCAS markets. While NEMDE co-optimises bids across the energy and FCAS markets, it does not always operate central dispatch with the objective of optimising the size of the largest contingency relative to the costs of procuring FCAS to manage frequency risk. The proponent considers that this approach can result in inefficient outcomes when FCAS costs are high compared to wholesale energy prices, as the largest generator or load may be dispatched at levels that generate higher FCAS costs than the value of the energy produced.

10 The proponent proposes that the NER place an obligation on AEMO to co-optimise the size of the largest generation contingency produced in dispatch. They propose that central dispatch should constrain the output of the largest scheduled or semi-scheduled generators or loads when:

- it reduces the amount of contingency FCAS requirements, which leads to overall cost savings to the system,
- it does not reduce system security, and
- it maintains market integrity.

11 The proponent acknowledges that imposing a blanket obligation to optimise contingency size in dispatch in all conditions and at all times may not be appropriate, due to potential impacts on large thermal generators' willingness to contract and the resulting effect on contract market liquidity and long-run investment efficiency. The contingency size optimisation rule change request, therefore, does not propose AEMO curtailing load or generation to manage contingency size if doing so would lead to long-run investment inefficiencies.

12 The proponent also acknowledges the technical challenge and associated costs of a blanket obligation for AEMO to co-optimise contingency size at all times and in all circumstances. In recognition that the costs of a full solution may not be justified by the benefits, the proponent argues that there should be scope for a partial implementation.

Allocating contingency FCAS costs using 'runway' cost allocation

13 Under current arrangements, the volume of contingency FCAS procured by AEMO is principally determined by the size of the single largest credible contingency. The costs for the procurement of this FCAS are allocated to generators and loads for raise and lower services respectively in proportion to their total energy generated or consumed. The proponent considers that these arrangements do not send efficient signals and result in smaller generators and loads bearing a disproportionate share of these costs, despite having a limited impact on the need for FCAS volumes, which exceed their size.

14 The proponent proposes applying 'runway' cost allocation to send more efficient signals and better align costs to larger generators and loads that are the driver of the additional FCAS requirements they impose on the system. Runway cost allocation assigns a greater share of costs to the largest units, which are most responsible for contingency FCAS costs, while significantly reducing the costs for smaller units. It does this by recovering contingency FCAS costs in proportion to the size of the unit involved, rather than in proportion to total generation.

15 The proponent proposes that runway pricing be applied to generators, in respect of contingency raise services, and loads in respect of contingency lower services. The proponent considers that it is appropriate for runway pricing to be applied to both load and generation, as applying cost

reflective signals to large loads would assist their response to scenarios, such as inter-regional separation, that occur in the NEM where reductions in the required volume of FCAS lower capacity leads to what the proponent considers to be dramatic cost savings for the system.

16 The proponent identifies that network elements like interconnectors currently don't incur contingency FCAS costs.[1] This is despite network contingencies being a major driver of FCAS costs in circumstances where there is inter-regional separation or a credible risk of inter-regional separation.[2] The proponent therefore poses the question of whether placing contingency FCAS costs on network elements or passing those costs on to generators or loads "behind the network element" would provide incentives to lower costs in the NEM (through reduced contingency FCAS volumes).

The Commission seeks stakeholder feedback in a number of areas

Our assessment framework

17 The Commission is bound by the National Electricity Law (NEL) and may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO).

18 Considering the NEO, and the issues raised in the rule change package, the Commission proposes to assess the requests against the following three assessment criteria.

- **Safety, Security, and Reliability** - The rule change package relates to the way in which dispatch minimises certain risks to system security, in particular, the size of the largest credible contingency. The rule changes also affect revenues accruing to certain generators, given the size of the largest credible contingency. This will also affect investment incentives in a way relevant to long-run reliability. The Commission will consider the impacts on system security in considering these rule changes. It will consider whether the rule change will enhance system security by limiting the size of the largest credible contingency and, therefore the size of the disturbances the system must remain secure against.
- **Principles of market efficiency** – The proponent views these rule changes as providing a market efficiency benefit by directly minimising the amount and costs of FCAS required, and internalising FCAS costs into market processes through better signals for operation and investment. The Commission will consider the efficiency benefits that could be created if the changes were to be made. The Commission intends to assess the extent to which the rule changes would lead to different dispatch outcomes and, therefore, costs relative to outcomes under existing arrangements.
- **Implementation considerations** - Implementation considerations arise from the necessary changes in AEMO's systems, as well as any long-run effects given reductions in contract market liquidity. The Commission will consider implementation costs for both AEMO and the industry more broadly. It intends to work with AEMO to appreciate the required systems changes and associated costs as well assess potential contract market liquidity impacts arising from the rule change's incentives.

Key assessment considerations

19 In assessing the rule change package against the NEO, the Commission has identified the following four key considerations, which we are particularly interested in stakeholder views on:

1 This was a design decision made at market start due to the technical limitations associated with allocating contingency FCAS costs on a cost-reflective basis

2 The Commission also understands that intra-regional network events that make the loss of a large generating station or a large load a single contingency can also lead to significant contingency FCAS costs under certain circumstances.

Is a rule change required to achieve benefits from contingency size optimisation?

20 The Commission will consider whether there are clearly identifiable barriers to achieving benefits under existing arrangements. The Commission notes that AEMO currently co-optimises contingency size in certain circumstances as part of its system security responsibilities. In this regard, existing arrangements may not preclude contingency size optimisation as proposed by the proponent. However, there may be benefits in creating more transparency and a clear regulatory framework around how this happens. In evaluating the proposal, the Commission will therefore consider whether the expected benefits would outweigh the costs of additional obligations, taking into account the associated regulatory and implementation costs and risks.

Whether the FCAS cost recovery framework should be expanded to cover network events

21 The proponent questions whether FCAS cost allocation frameworks should be extended to cover network events, given their significance as a driver of contingency FCAS costs.

22 While network events are strong drivers of contingency FCAS costs, recovering FCAS costs from networks may result in costs being passed through to consumers. Such an outcome would not lead to a more cost-reflective allocation. Allocating FCAS costs to the generators or loads that are associated with the energy flowing through the relevant network element may lead to a more cost-reflective outcome, but would likely involve a degree of complexity that may not be justified given the magnitude of possible benefits. For this reason, the Commission is, at this time, not intending to include network event contingency FCAS cost allocation in the scope of the rule change. The Commission, however, seeks stakeholder inputs on this view.

Whether contingency size co-optimisation and runway cost allocation are complementary mechanisms or substitute mechanisms

23 The proponent considers that both rule changes should be implemented together to enhance the efficiency of the contingency FCAS framework. The Commission notes that the two proposed mechanisms aim to achieve the same broad goals via different mechanisms. If both measures pursue the same objective by different mechanisms, the Commission will consdier whether it is preferable to identify a single approach to avoid implementing two overlapping solutions. Stakeholder feedback is particularly sought on the relationship between the two rule changes.

Whether there are market integrity risks from increasing financial risk due to runway cost allocation

24 The Commission will also consider whether runway pricing creates additional market integrity risks. Runway pricing concentrates financial exposure on the unit that represents the largest credible load or generation contingency. Inter-regional separation events that drive contingency FCAS costs exhibit tail-risk characteristics, so contingency FCAS costs can spike unpredictably and materially, increasing cost volatility for affected units. The Commission notes that additional financial risk from runway pricing may raise investment risk premiums and other costs that could distort investment or other market behaviour. The Commission will assess whether participants can effectively manage the additional risk through operational measures or other mechanisms to mitigate any risks.

Submissions are due by 18 December 2025 with other engagement opportunities to follow

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

26 Written submissions responding to this consultation paper must be lodged with Commission by

18 December 2025 via the Commission's website, www.aemc.gov.au. Stakeholders should specify which rule change proposal/s their submission or parts of their submission relate to.

27 There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions. See the section of this paper about "How to engage with us" for further instructions and contact details for the project leader.

28 The Commission anticipates publishing a draft determination on 26 March 2026. This includes a four-week extension to provide additional time to undertake modelling and other analytical work necessary to inform the Commission's assessment.

Full list of consultation questions

Question 1: Is there a substantive problem or evidence of an emerging one?

- Do you consider that the current allocation of contingency FCAS costs leads to a material loss of market efficiency?
- To what extent does AEMO's current practices already address the periods of greatest concern to the proponent and thereby reduce the materiality of the issue?

Question 2: Will contingency size optimisation address the issue raised by the proponent?

- Do you consider that contingency size co-optimisation will address the issue identified by the proponent? Are there other factors or solutions that should be considered?
- Do you have any views on how to manage the potential risks to market integrity?
- How should the limits on contingency size optimisation issues be expressed to avoid market integrity risks?

Question 3: Will runway contingency FCAS cost allocation address the issues identified by the proponent?

- Do you consider that runway contingency FCAS cost allocation will address the issue identified by the proponent? Are there other factors or solutions that should be considered by the Commission when considering this?
- Are you aware of any issues associated with the practicality of applying runway pricing to large loads? What load threshold should be applied?
- Are you aware of any approaches or methods that could be used to extend contingency FCAS cost allocation frameworks to incorporate network events in a way that enhances cost reflectivity?

Question 4: Do stakeholders consider the two rule changes to be complementary

- Do you consider contingency size co-optimisation and runway FCAS cost allocation to be complementary mechanisms that work together or substitute mechanisms which aim to achieve the same outcomes via different methods?
- What is your understanding of the interactions between these two mechanisms, should they be implemented together?

Question 5: Do stakeholders agree with the benefits identified from contingency size optimisation and runway FCAS cost allocation

- Do you agree that participant bidding is likely to change, given the runway cost allocation to achieve the benefits identified by the proponent?
- Do you agree that contingency size optimisation will enhance market efficiency as identified by the proponent?

Question 6: What are your views on the costs, benefits, and risks of the proposed solution

- Do you agree with the costs and benefits of the package of proposed rule changes as put forward by the proponent?
- Do you have any insights on how the costs and benefits of the proposal may change given the transitioning power system?
- Do you consider the market integrity risks identified by the proponent in respect of contingency size optimisation to be material and how should the best be managed should the rule be made?
- How do you see the change in the contingency risk profile of the NEM affecting costs and benefits over the course of the transition?

Question 7: Assessment framework

Do you agree with the proposed assessment criteria? Are there additional criteria that the Commission should consider or criteria included here that are not relevant?

How to make a submission

We encourage you to make a submission

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.

We have included questions in each chapter to guide feedback, and the full list of questions is above. However, you are welcome to provide feedback on any additional matters that may assist the Commission in making its decision.

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with Commission by **18 December 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 ERC0359 or ERC0360.[3]

You may, but are not required to, use the stakeholder submission form published with this consultation paper.

Tips for making submissions are available on our website.[4]

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, defamatory, vexatious or irrelevant content, or content that is likely to infringe intellectual property rights).[5]

For more information, you can contact us

Please contact us with questions or feedback at any stage, noting the project code.

Email:	aemc@aemc.gov.au
Telephone:	(02) 8296 7800

3 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.

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

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

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1 The context for the package of rule change requests

This consultation paper invites stakeholder feedback on the package of rule change requests submitted by Grids Energy Pty Ltd (proponent). These propose changes to the contingency FCAS arrangements in the NEM, which aim to optimise contingency size in dispatch and implement the 'runway' method for allocating contingency FCAS costs.

This chapter introduces each rule change and provides context on the issues and the NEM contingency FCAS frameworks relevant to the rule changes.

1.1 The proponent has submitted two rule changes as a package, which are being consulted on in this paper

The proponent submitted a package containing two related rule change requests. This paper consults on both proposals due to their shared subject matter and common objective of enhancing the efficiency of the NEM's contingency FCAS frameworks. Following consultation, the Commission may consolidate the two rule change requests. The proposals are summarised below

- **ERC0359 – Optimising contingency size in dispatch:** Under current arrangements, FCAS costs are generally not co-optimised with wholesale energy costs during dispatch, except in limited circumstances. The proponent considers this can lead to inefficient dispatch outcomes, particularly when FCAS costs are high. They propose that co-optimising contingency size in dispatch would help reduce these costs. For more information, see: https://www.aemc.gov.au/rule-changes/optimising-contingency-size-dispatch
- **ERC0360 – Allocating contingency FCAS costs:** Current arrangements recover contingency FCAS costs from generators and loads on a proportional basis, which the proponent views as only weakly cost-reflective. They propose a 'runway' cost allocation approach, which they consider more cost reflective. This method would concentrate costs on the largest generators or loads, whose potential loss defines the contingency size and drives the FCAS requirement. For more information, see: https://www.aemc.gov.au/rule-changes/allocating-contingency-fcas-costs

1.2 The rule changes relate to the NEM's contingency FCAS frameworks

Contingency Frequency Control Ancillary Services (FCAS) works together with Regulation FCAS to manage NEM frequency.[6] While regulation FCAS involves the ongoing correction of the generation/demand balance in response to minor deviations in load or generation, contingency FCAS helps maintain power system frequency stability in the event of disturbances, referred to as contingency events. The proponent's package of rule changes relates exclusively to contingency FCAS in the NEM, which is introduced further below.

1.2.1 Contingency FCAS maintains frequency stability following a power system disturbance

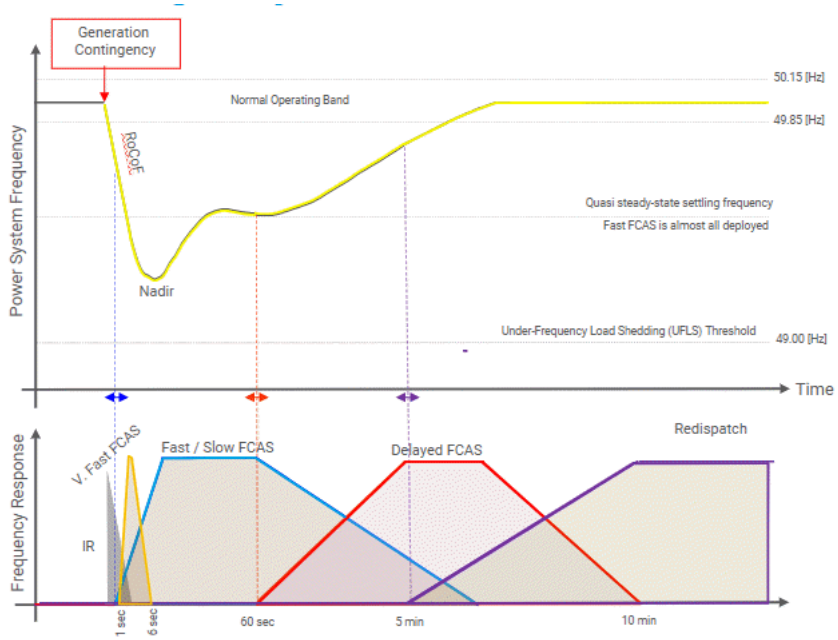
Frequency control is a core requirement for power system security. To maintain a stable frequency, AEMO must instantaneously balance electricity supply and demand at all times.

AEMO procures contingency FCAS to rapidly correct any active power imbalance following a contingency event, such as the unplanned loss of a generator, load, or network element, in order to arrest, stabilise, and return the power system frequency to its synchronous speed of 50 Hz.

6 Regulation FCAS is provided by generators on Automatic Generation Control (AGC). The AGC system allows AEMO to continually monitor the system frequency and to send control signals every four seconds to generators providing regulation services to increase or decrease generation in such a manner that the frequency is maintained within the normal operating band of 49.85Hz to 50.15Hz on an ongoing basis.

AEMO procures sufficient contingency FCAS across eight raise and lower services across four response and sustain time bands: very fast (1 second), fast (6 seconds), slow (60 seconds), and delayed (5 minutes). These services operate together after a contingency to recover system frequency within the bands and timeframes set out in the frequency operating standard. These services and their relationship are illustrated in Figure 1.1 below.

Figure 1.1: The NEM's contingency FCAS services



1.2.2 AEMO enables sufficient contingency FCAS in dispatch to cover the largest credible load and generation contingency every 5 minutes.

AEMO determines contingency FCAS volumes for each service based on its assessment of needs, considering the largest credible contingency and other relevant operating conditions. AEMO updates these requirements every five-minute dispatch interval to reflect current system conditions and the largest credible contingency calculated by the national electricity market dispatch engine, NEMDE.

NEMDE minimises the combined cost of energy and FCAS to meet demand and manage frequency risk from the largest credible contingency, using market participants' energy offers and FCAS bids. Generators submit energy offers and separate FCAS bids, including raise/lower and fast/slow services. AEMO then sets the market price for each FCAS service at the marginal FCAS bid required to address the largest contingency. AEMO co-optimises participant energy bids with FCAS bids but they do not currently co-optimise contingency size with FCAS volumes or co-optimise across the different FCAS products.[7]

1.2.3 Contingency FCAS costs are recovered from load and generation on a proportional basis.

The NER imposes the following general principle of causer pays on the allocation of FCAS costs.[8]

7 As an example, AEMO doesn't currently co-optimise the provision of 1 second FCAS with 6 second FCAS.

8 Clause 3.1.4(a)(8) of the NER.

"Where arrangements require participants to pay a proportion of AEMO costs for ancillary services, charges should where possible be allocated to provide incentives to lower overall costs of the NEM. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions"

Consistent with this principle, costs for raise FCAS are recovered from generators, and costs for lower FCAS are recovered from loads. AEMO recovers the costs of contingency raise services from market generators because those services manage the loss of the largest generator on the system. It recovers the costs of lower contingency services from market customers, as those services manage the loss of the largest load. Contingency raise and lower FCAS costs are allocated to loads and generators in proportion to their respective share of total demand and total generation.[9]

Contingency FCAS costs, however, are not recovered from networks in respect of network contingency events, even though network contingency events can be a material driver of contingency FCAS costs. Network events such as the loss of a major transmission element or interconnector can set the size of the largest credible contingency in a region, depending on the level of export or import, and therefore drive the volume of contingency FCAS required.

1.2.4 Contingency FCAS costs are generally small and not expected to increase over the course of the transition

Contingency FCAS costs in the NEM are generally very small, with costs historically averaging under 0.5% of total market turnover.[10] These costs were low because the coal, gas, and hydro plant in the NEM at its commencement had an excellent FCAS supply capability, vastly exceeding FCAS demand under most conditions.[11]

The withdrawal of thermal generation in some NEM regions, and the consequential loss of some of this FCAS capability, saw an increase in FCAS costs given the emergence of physical FCAS limits in some regions, in the late 2010s. Since that time, contingency FCAS costs have moderated but generally remain between 1% and 1.5% of total market turnover on a quarterly basis. The Commission understands this moderation in FCAS costs could be attributed to increased competition from grid-scale batteries, which currently have a combined FCAS market share of 56% across the NEM.[12] Figure 1.2 presents the history of FCAS prices since 2020, showing the moderation in annual contingency FCAS costs.

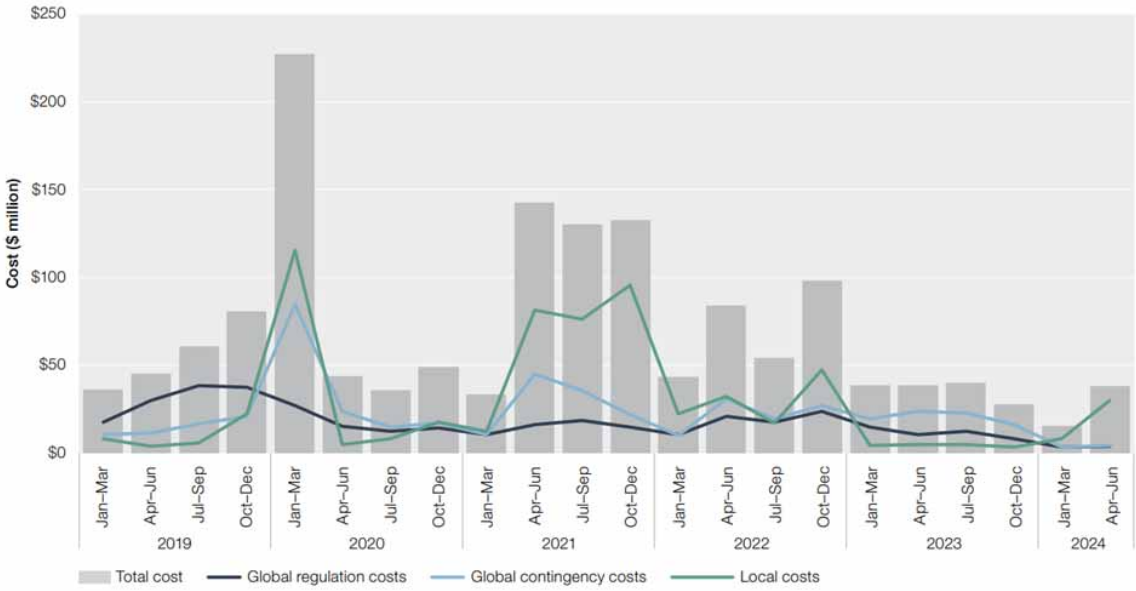
9 Clause 3.15.6A(f) and (g) of the NER.

10 Joel Gilmore & Tahlia Nolan & Paul Simshauser, 2022. "The Levelised Cost of Frequency Control Ancillary Services in Australia's National Electricity Market," Working Papers EPRG2202, Energy Policy Research Group, Cambridge Judge Business School, University of Cambridge.

11 Ibid.

12 AEMO, Quarterly Energy Dynamics, October 2025, p. 43.

Figure 1.2: Historic FCAS costs



Note: Record FCAS costs in the January to March quarter 2020 were due to high local costs in South Australia when it was islanded for several weeks following the loss of the Heywood interconnector. In January 2020 bushfires also drove high prices across the NEM.

Source: AER, State of the energy market 2024, p. 61.

Despite the continued exit of thermal generation, contingency FCAS costs are not expected to increase given the implementation of large battery energy storage systems (BESS) capacity in the NEM. Gilmore, Simhauser and Nolan forecast contingency FCAS prices to remain at current levels, well below the spikes observed in 2020 and 2021, over the investment time horizon to 2035, given the economics and expected levels of BESS investment.[13]

1.2.5 Contingency FCAS costs can increase significantly given regional separation events

Contingency FCAS is a global service that can normally be provided anywhere in the NEM these costs of which are generally small, given the ample supply of FCAS capability across the NEM. Contingency FCAS costs can, however, increase significantly when an interconnector between NEM regions trips or a trip becomes credible. This situation triggers a requirement to procure FCAS on both sides of the relevant interconnector. In this case, scarcity of FCAS capability in an affected region can lead to significant increases in FCAS prices and costs.

The most significant example of this situation was the historically high prices and costs experienced in South Australia during an 18-day separation of the Victorian and South Australian power systems after a storm event knocked out key transmission lines on 31 January 2020. This 18-day 2020 separation event saw a 60 Second FCAS price jump to $14,500/MWh, leading to $21million in direction costs, much of which was contingency FCAS-related.[14]

Most recently, a credible risk of separation between South Australia and Victoria in Q3 2025 led to a dramatic increase in contingency lower 1-second service (L1SE), which rose from less than $1 million in Q3 2024 to $47 million in Q3 2025.[15] The total costs of this single service dominated

13 Joel Gilmore & Tahlia Nolan & Paul Simshauser, 2022. "The Levelised Cost of Frequency Control Ancillary Services in Australia's National Electricity Market," Working Papers EPRG2202, Energy Policy Research Group, Cambridge Judge Business School, University of Cambridge.

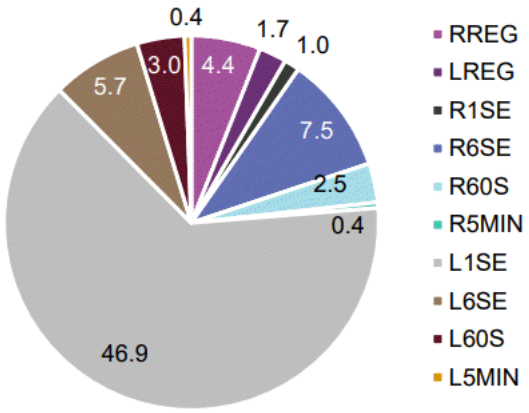
14 AEC. Reaching new heights – NEM system costs, Apr 30, 2020, See https://www.energycouncil.com.au/analysis/reaching-new-heights-nem-system-costs/

15 AEMO, Quarterly Energy Dynamics, October 2025, p. 43.

national contingency FCAS recovery costs in Q3 and illustrate the extent to which a credible risk of separation can drive total FCAS costs nationally. Figure 1.3 shows the extent to which the lower L1SE dominated national contingency FCAS costs due to this credible risk of separation between SA and VIC.

Both of these events illustrate the sensitivity of contingency FCAS pricing to sudden changes in system configuration, local availability of response capability, and the central dispatch assessment of the largest credible contingency.

Figure 1.3: Contingency FCAS cost breakdown by service Q3 2025



Source: AEMO, Quarterly Energy Dynamics, October 2025, p. 43.

1.3 This rule change package continues the AEMC's frequency control reform program

This rule change relates to frequency control services in the NEM. The AEMC has had an active frequency control reform program since 2017 which coordinates with AEMO and other bodies to implement a staged set of reforms, including rule, procedure, and guideline changes, so that frequency services meet future NEM needs while minimising costs and maintaining reliability.

There have been eight major elements of the AEMC's frequency control program with this rule change representing the ninth. The frequency control reform program is introduced in Figure 4 below.

Contingency size optimisation and runway cost allocation have been considered in several elements of the AEMC's frequency control reform program.

- The 2017 frequency control frameworks review identified runway pricing as an option for making contingency FCAS cost allocation arrangements more cost reflective. It was identified as an option for future FCAS frameworks and was not the subject of a recommendation for change at that time.[16]
- The 2022 review of the frequency operating standard considered contingency size optimisation as a more flexible and efficient alternative to imposing a fixed maximum contingency size ceiling in the mainland NEM, as is currently the case in Tasmania.[17] The

16 AEMC, Frequency control frameworks review, Draft report, 20 March 2018, p. 177.

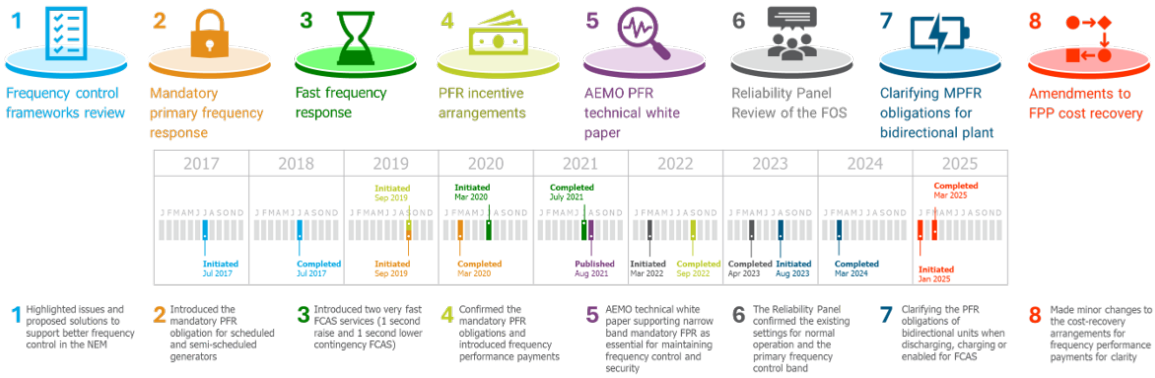
17 The frequency operating standard currently limits the largest credible contingency size in Tasmania to 144 MW.

Panel considered that the Commission may want to investigate a more explicit co-optimisation of marginal contingency FCAS costs and contingency sizes in a future review or rule change.[18]

- The 2024 enhancing reserve information (formerly operating reserves) rule changes also briefly considered contingency size optimisation in the context of procuring regional FCAS, but concluded that these were complex issues that would be best looked at through a separate rule change.[19]

While these processes considered contingency size optimisation or runway cost allocation in varying degrees, this rule change package is the first occasion on which the Commission will consider specific framework changes in this area.

Figure 1.4: AEMC frequency control reform program



1.4 We have started the rule change process

This paper is the first stage of our consultation process.

A standard rule change request includes the following formal stages:

- a proponent submits a rule change request
- the Commission commences 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).

The Commission anticipates publishing a draft determination on 26 March 2026. This timeline includes a four-week extension to provide additional time for undertaking modelling and other analytical work necessary to inform the Commission's assessment in support of the draft determination. We expect to publish a final determination by the end of June 2026.

18 Reliability Panel, Review of the frequency operating standard, Final determination, 6 April 2023, p. 19.
19 AEMC, Enhancing reserve information final determination, 21 March 2024, Chapter 5.

Information on how to provide your submission and other opportunities for engagement is set out at the front of this document.

You can find more information on the rule change process on our website.[20]

To make a decision on this proposal, we seek stakeholder feedback on how we propose to assess the request, the stated problem and the proposed solutions.

20 See our website: https://www.aemc.gov.au/our-work/changing-energy-rules

2 The problem raised in the rule change package

The optimising contingency size, and runway cost allocation rule changes both aim to address what the proponent considers to be a shortcoming in existing contingency FCAS arrangements.

2.1 The proponent considers current arrangements create inefficient contingency FCAS costs

2.1.1 Dispatch doesn't generally co-optimise the size of the largest contingency

The contingency size optimisation rule change request considers that, under current arrangements, AEMO does not operate central dispatch with the aim of optimising the size of the largest contingency against the costs of procuring ancillary services to manage the associated contingency risk.[21] While there is some co-optimisation between wholesale and FCAS markets to enable the lowest cost contingency FCAS required to 'minimise the costs of addressing the largest credible contingency, central dispatch does not consider adjusting the size of the largest contingency to maximise market benefits.[22] The proponent considers this leads to situations where generators or loads are dispatched at levels that incur greater system costs than the benefits that capacity provides.

The Commission understands that AEMO doesn't commonly co-optimise the largest contingency size, and that inefficient dispatch outcomes may be possible in circumstances where contingency FCAS costs are high relative to wholesale energy costs. The Commission, however, notes that AEMO does, under certain circumstances, co-optimise contingency size but as part of their system security obligations. Further discussion on when and how AEMO does this is provided in Section 2.2. The Commission, therefore, will need a clear understanding of the materiality of the potential inefficiencies, given AEMO's existing practices include contingency size co-optimisation.

2.1.2 Contingency FCAS cost recovery is not sufficiently cost reflective

The runway cost recovery rule change request is to implement 'runway' cost allocation in place of the current arrangements, which allocate contingency FCAS costs on a proportional basis.

The proponent considers that proportional contingency FCAS cost recovery socialises the costs of investment and operational decisions in a way that increases contingency sizes and FCAS requirements across all generators and loads, including those not responsible for these costs. As a result, smaller generators and loads bear a disproportionate share of these costs, despite having a limited impact on the need for FCAS volumes, given their size. The proponent notes that this can lead to inefficient operating decisions by those generators. The proponent identifies the following example of the problem with current arrangements.

> *"Currently, in situations where the price of contingency FCAS increases or could increase, we see smaller generators dramatically increasing their wholesale market bids and curtailing their output to avoid the contingency FCAS costs that would be imposed on them. This is very inefficient! At times where the market communicates a lack of contingency FCAS capacity through a high price we would like to lower the total FCAS capacity required where it's efficient to do so. Small generators withdrawing capacity from the wholesale market does not help achieve this, in fact it can exacerbate the problem as withdrawing this wholesale capacity can cause some capacity that would have been providing FCAS to be reallocated to*

21 Grids Energy, contingency size optimisation rule change request, p. 2.
22 Ibid.

wholesale energy, pushing up both the wholesale energy price and the contingency FCAS price. Under runway pricing the costs imposed on small generators would be greatly reduced, even during high FCAS price scenarios, which makes them less likely to curtail output during these scenarios.

The proponent considers that socialising FCAS costs doesn't incentivise generators and loads to make offers for energy in a way that considers the contingency FCAS costs they could incur because of being dispatched in the energy market.They note that an example of this is that currently, when the largest generation/load source increases or decreases its output, most of the FCAS costs or savings are borne by other generators. This means that each participant's costs are not well correlated with their own output, but rather with the output of the largest generation or load source.[23]

The Commission acknowledges that proportional FCAS cost recover is only partially cost reflective. These arrangements were established by the Australian Competition and Consumer Commission (ACCC) in 2001. At the time, it was noted that technical difficulties prevented more cost-reflective arrangements from being pursued.[1]

The proponent noted that back in 2001 a simple cost allocation method was chosen to spread the costs broadly as a temporary measure before a 'second phase' of work could be done to explore better ways to allocate costs. A particular objective would be to structure costs in a way that they a borne by entities that can reduce the costs of the ancillary services. A main barrier to more sophisticated and effective methods was that it was not technically possible at the time.[24]

2.2 How material are the issues raised in the package of rule changes

The Commission invites stakeholder input on the materiality of issues raised by the proponent in the package of proposed rule changes.

2.2.1 How material is the problem caused by not optimising contingency size in dispatch

The Commission accepts that co-optimising contingency size in dispatch may deliver efficiency benefits under certain conditions. These conditions typically arise when inter-regional separation occurs or the risk of separation is credible, and where there is physical scarcity of contingency FCAS in an affected region.

The materiality of the issue raised by the proponent depends on the frequency of such events. The Commission seeks stakeholder views on the frequency of these circumstances and whether they occur often enough, or are likely to occur more frequently in the future, such that the benefits of change justify any associated costs.

The Commission also considers it important to assess the materiality of the problem in the context of AEMO's current operational practices. AEMO already co-optimises contingency size in dispatch under specific conditions consistent with its system security responsibilities. The Commission understands that AEMO's current practices involve co-optimising interconnector flows with the price of FCAS when they represent the largest credible contingency in a region at risk of separation AEMO also co-optimises generation contingencies on a case-by-case basis when the criteria set below are met.[25]

23 Grids Energy, allocating contingency FCAS costs rule changes, p. 6.
24 Ibid, p. 3.
25 AEMO, Constraint formulation guideline, section 6.5

Box 1: AEMO generation contingency size optimisation criteria

AEMO currently co-optimises the largest credible contingency size with FCAS costs in the following conditions as set out in their constraint formulation guideline.

- For network contingency situations where there is a large amount of generation at risk (> 1.5x largest regional generating unit) or there is a scarcity of FCAS (such as in island conditions), AEMO will determine, on a case by case basis, whether moving generating units at risk to the LHS of the constraint equation is appropriate, taking into account considerations such as the risk of power system security violations due to the FCAS requirement exceeding the FCAS availability.

AEMO provides the following example in its constraint formulation guidelines to illustrate the circumstances when it would co-optimise the size of the largest genearation contingency with the additional FCAS costs by moving the largest credible generation contingency to the left-hand side (LHS) of the constraint equation thereby making it a decision variable to be optimised.

- Consider the case of a 400 MW power station of three units with one double circuit connection to the transmission system, in a region where the FCAS raise requirement is typically 130 MW, and the maximum FCAS raise service available in the region is 250 MW. When the double-circuit connection is reclassified as a credible contingency, or one circuit is out of service on a prior outage, system security requires that the generation from the power station must be limited to no more than 250 MW (ignoring load relief, inertia and demand effects for simplicity). If the power station were dispatched above 250 MW, there would be insufficient raise FCAS to cover the generation lost through the credible contingency. This situation is best managed dynamically by moving the generation risk to the LHS of the relevant FCAS raise constraint equations, so the power station generation can be co-optimised with the raise FCAS capability. This avoids introducing and continually updating discretionary constraints to limit the power station generation.

The Commission understands that these circumstances generally involve credible and actual interregional separation, which produces the high FCAS prices the proponent identifies as generating the efficiency benefits that justify the contingency size optimisation rule change. The Commission seeks to understand the extent to which AEMO's current practices already address the periods of greatest concern to the proponent and thereby reduce the materiality of the problem caused by not optimising contingency size in dispatch.

The Commission also understands that AEMO performs contingency size optimisation under these conditions as an alternative approach to setting a cap on the allowable contingency size as is currently the case in Tasmania. Contingency size optimisation represents a dynamic, more flexible, and economically beneficial means of respecting limits in contingency FCAS availability than imposing a fixed contingency size ceiling.

2.2.2 How material is the problem caused by not allocating FCAS costs proportionally

The Commission understands that current arrangements are seen as weakly cost-reflective because contingency raise and lower services are recovered proportionally from generation and load, irrespective of the extent to which the generation or load created demand for contingency FCAS services.

As the proponent notes, these arrangements were implemented as a deliberately loose "causer pays" approximation to reflect the impact of generator and large-customer trips on the system.

The Commission notes the ACCC's view at the time that this loose "causer pays" approach was chosen to spread costs across a broad base until more sophisticated mechanisms can be implemented, thereby minimising distortions to decision-making.[26]

The Commission seeks stakeholder feedback to better understand the materiality of the proponent's efficiency concerns, including whether rising or high contingency FCAS prices prompt small generators to curtail output. The Commission is aware that such outcomes may have occurred during the SA separation event in 2020.

Question 1: Is there a substantive problem or evidence of an emerging one?

- Do you consider that the current allocation of contingency FCAS costs leads to a material loss of market efficiency?
- To what extent does AEMO's current practices already address the periods of greatest concern to the proponent and thereby reduce the materiality of the issue?

26 ACCC, Applications for authorisation of National Electricity Code Changes - Ancillary services amendments (A90742 - A90744), 2001, p.34

3 The package of proposed solutions

This chapter presents the proponent's package of proposed solutions to the problems presented in Chapter 2.

3.1 The proponent proposes requiring AEMO to optimise contingency size in dispatch where there are market benefits

The proponent proposes that central dispatch should optimise contingency size in dispatch by constraining the output of scheduled or semi-scheduled generators or loads when:[27]

1. It reduces the amount of contingency FCAS requirements, which leads to overall cost savings to the system,
2. It does not reduce system security, and
3. It maintains market integrity.

Where "overall cost savings" indicate that market benefits are possible, as the savings from the reduction in contingency FCAS costs are larger than other system costs that may increase by constraining the largest unit, like wholesale energy.

The requirement to maintain market integrity indicates that interventions like this in the central dispatch process can negatively impact operational or commercial outcomes for participants. Where these interventions would lead to long-run costs (such as a reduction in the long-run efficiency of bids or loss of investor or participant confidence) that outweigh the benefits of the interventions, these interventions should not be taken. The market integrity implications of the proponent's proposal are discussed further in the section on costs.

The contingency size optimisation rule change proposes:[28]

1. That there are clear, explicit obligations on AEMO in the NER to manage contingency sizes where it lowers total costs to the system.
2. The NER should explicitly state any obligations, aims, principles, etc giving clarity on the extent that contingencies should be managed, such as not curtailing load or generation to manage the contingency size when it would lead to long-run inefficiencies.
3. There should be provisions for where it is not technically or financially feasible for AEMO to do a full implementation of this obligation. These provisions should strongly encourage AEMO to implement solutions that can partially meet this obligation, and to improve on those solutions over time, where prudent to do so.

The proponent considers that co-optimising contingency size in dispatch would, in practice, lead to large generators, those responsible for the largest credible contingency, being dispatched at lower levels than under current arrangements. These generators would be constrained, while smaller generators would be dispatched at higher levels. This would create market benefits when the increase in wholesale electricity costs from dispatching these smaller units is offset by savings in FCAS costs, due to the smaller contingency size.

The Commission notes that the proponent doesn't propose an obligation for AEMO to co-optimise contingency size under all circumstances. Instead, the contingency size optimisation rule change request proposes that AEMO co-optimise such contingencies under circumstances where there will be market benefits without compromising market integrity or causing long-run costs and that

27 Grids Energy, optimising contingency size in dispatch rule change request, p. 2.
28 Ibid, p. 4.

provisions be made for situations where it is not technically or financially feasible for AEMO to fully implement this obligation.[29]

The proponent considers the line at which it makes sense to curtail large generators or loads without negatively impacting market integrity or imposing long-run costs to be tricky, and leaves it to the Commission to determine where that line is and how it can be expressed. For instance, through principles, aims or other mechanisms used in these situations.[30]

Stakeholder feedback is sought on the proposed solution and whether this solution is appropriate, particularly given the market integrity issues at play and what approaches may be applied to defining the circumstances in which co-optimisation should occur without causing market integrity issues.

Question 2: Will contingency size optimisation address the issue raised by the proponent?

- Do you consider that contingency size co-optimisation will address the issue identified by the proponent? Are there other factors or solutions that should be considered?
- Do you have any views on how to manage the potential risks to market integrity?
- How should the limits on contingency size optimisation issues be expressed to avoid market integrity risks?

3.1.1 The proponent proposes allocating contingency FCAS costs using 'runway' cost allocation methods

The runway cost allocation rule change proposes that the current 'proportional method' for FCAS contingency cost allocation (proportional to a participant's share of total generation or load) be substituted with a 'runway pricing method' (that better reflects a participant's contribution to FCAS procurement requirements).

The proponent proposes the following change to clauses 3.15.6A(f) and (g) of the NER. The proponent proposes applying runway pricing as is currently applied in the Wholesale Energy Market (WEM) in Western Australia. The proponent has utilised the WEM's version of runway pricing to allocate its version of FCAS raise costs.[31]

Box 2: Proposed change to Clauses 3.15.6A(f) and (g) of the NER to implement runway pricing.

The proponent proposes the following to implement runway pricing

TA = RTCRSP x PARTICIPANT RUNWAY COST FACTOR x -1

Note: Where:

- TA - is the trading amount payable by the Cost Recovery Market Participant in respect of the relevant region and trading interval.
- RTCRSP – is the sum of the the global and local market ancillary service requirement cost for that region, for the relevant trading interval.

29 Ibid, p. 4.
30 Grids Energy, allocating FCAS costs rule change, p. 3.
31 Grids Energy, allocating FCAS costs rule change, p. 3

- PARTICIPANT RUNWAY COST FACTOR – The runway cost allocation factor (introduced in section 3.2.1.

3.1.2 What is the 'participant runway cost factor'?

The rule change request identifies runway cost allocation as originating from the allocation of airport runway costs, where different aircraft require varying runway lengths. Runways are sized to accommodate the largest or heaviest aircraft, and smaller aircraft do not use the full length. In this model, smaller aircraft pay only for the portion they use, while larger aircraft cover the cost of the entire runway.[32]

Applying this principle to power generation means that larger generators and loads would bear the cost of the additional FCAS requirements they impose on the system. The example provided by the proponent and reproduced in Figure 3.1 illustrates runway cost allocation outcomes for five generators of varying sizes. Compared to current cost allocations, runway pricing assigns a greater share of costs to the largest unit, while significantly reducing the costs for smaller units.

The example calculates the runway cost factor for each individual generator (and could be equivalently done for load), the factors would need to be summed for each participant.

The proponent considers that if it is technically infeasible to use all generator and load outputs in the calculation due to cost and complexity, a threshold can be chosen where any load or generation amounts below the threshold are excluded from the calculation. A low enough threshold, say, under 5MW, will not materially change the allocations to those generators or loads left in the calculation.

32 Grids Energy, Allocating contingency FCAS costs rule change request, p. 4.

Figure 3.1: Participant runway cost factor calculation and example

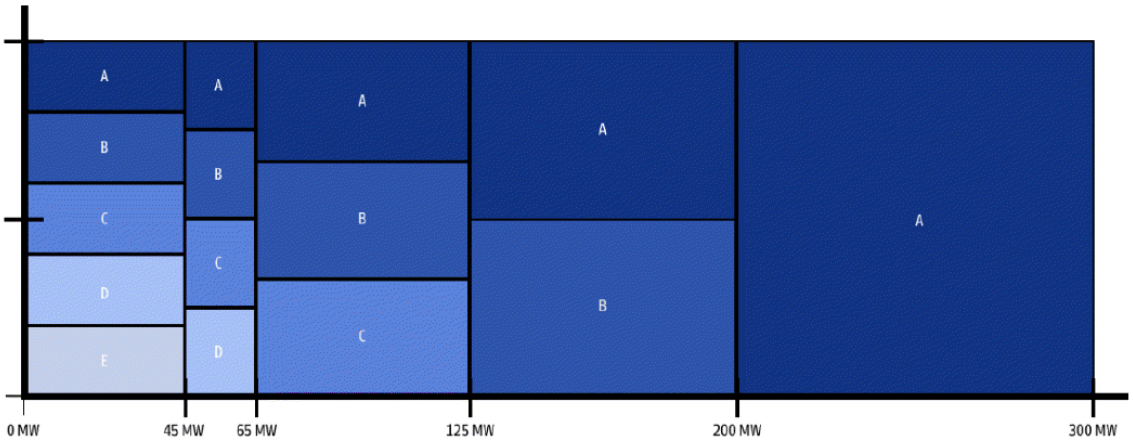


Figure 1 Runway pricing cost allocation example between 5 generators of varying output

Table 1 Proportional cost allocation and runway pricing cost allocation comparison between 5 generators of varying output

Generator	A	B	C	D	E
Output (MW)	300	200	125	65	45
Current cost factor (%)*	40.8	27.2	17	8.8	6.1
Runway cost factor (%)	57.2	23.8	11.3	4.7	3

*Using the proportional method of generator output/total generator output currently used in the NEM
Source: Grids Energy, allocating FCAS costs rule change request, p. 4.

3.1.3 The proponent proposes 'runway' cost allocation be applied to both generation and load

The runway cost rule change proposes runway pricing be allocated to both contingency FCAS raise and lower. Under this proposal, both generators and loads would be exposed to runway cost allocation.[33]

We note that the WEM implementation of runway pricing is applied solely to generators with lower contingency FCAS costs applied to loads on a proportional basis. The proponent, however, considers that there is more reason to apply runway pricing to loads in the NEM than in the WEM, because the NEM has large loads that are more sensitive and flexible in adjusting their operations to short-run energy prices. The proponent also identifies that the NEM has inter-regional

33 Grids Energy, allocating contingency FCAS costs rule change, p. 9.

separation risk, which is an important driver of FCAS costs, while the WEM does not face an equivalent separation and regional FCAS requirement.[34]

The proponent considers that implementing runway pricing means that during or when inter-regional separation in the NEM is credible, large loads have stronger incentives to reduce consumption and lower the amount of contingency reserves required, compared to the current cost allocation mechanism.[35]

The proponent also identifies the value of applying runway pricing to large loads in the NEM, as investment and planning decisions are currently being made on new large scale loads. Implementing this change now, as opposed to deferring it, gives certainty to project developers and participants on the costs they may incur throughout the life of these projects. This also gives opportunities to change the configuration of projects, such as smaller electrolysers, pumping stations, or batteries, if they're intending on running them during periods of high FCAS, lower costs.[36]

The Commission can see the potential value of runway pricing acting as a signal informing investment decision-making of new large loads entering the market, such as large data centres. These large loads may cause a future increase in lower contingency FCAS. The Commission seeks stakeholder feedback on the value of including loads in a runway cost allocation for lower contingency FCAS services and some of the practical considerations.

3.1.4 The proponent questions whether the FCAS cost recovery approach should be extended to include network events.

The proponent identifies that network elements like interconnectors currently don't incur contingency FCAS costs. This is despite the fact that sometimes they are the largest credible contingency and therefore the FCAS 'volume setter'. For this reason the proponent considers that, in principle, imposing contingency FCAS costs on the network element may lead to lower system costs.[37]

The proponent identifies that extending contingency FCAS cost recovery frameworks to network events was considered desirable at the commencement of the market, referring to the 2001 ACCC determination on contingency FCAS costs which recommended that:[38]

"any review of the cost allocation should also consider the role of network outages in causing a need for contingency FCAS."

The proponent poses the question of whether putting contingency FCAS costs onto network elements or passing those costs on to generators or loads "behind the network element" would provide incentives to lower costs in the NEM (through reduced contingency FCAS volumes).

While the proponent doesn't explicitly propose expanding contingency FCAS cost recovery frameworks to cover network events, the Commission appreciates their significance as a driver of contingency FCAS costs and understands that network events will need to be part of any truly cost-reflective framework for contingency FCAS cost allocation.

The Commission is, however, alive to the challenges of this task. Including networks in a runway pricing approach may mean that costs are simply passed through to consumers who are not

34 Ibid.
35 Ibid.
36 Ibid.
37 Grids Energy, allocating contingency FCAS costs rule change request, p. 1.
38 ACCC, Applications for authorisation of National Electricity Code Changes -Ancillary services amendments (A90742 - A90744), 11 July 2001. p. 34.

individually responsible or able to manage the risks associated with a network event. Such an outcome would not lead to a more cost-reflective allocation. Allocating FCAS costs to the generators or loads that are 'behind the network element', and therefore associated with the energy flowing through the relevant network element, may lead to a more cost-reflective outcome but may involve a degree of complexity not justified given the magnitude of possible benefits.

For these reasons, the Commission is not currently minded to expand the scope of the allocating contingency FCAS costs rule change to include FCAS cost recovery from networks. The Commission will make its decision on the scope of this rule change after considering submissions to this consultation paper. The Commission is therefore particularly interested in stakeholder views on approaches that may be used to extend contingency FCAS cost allocation frameworks to incorporate network events in a way that enhances cost reflectivity.

Question 3: Will runway contingency FCAS cost allocation address the issues identified by the proponent?

- Do you consider that runway contingency FCAS cost allocation will address the issue identified by the proponent? Are there other factors or solutions that should be considered by the Commission when considering this?
- Are you aware of any issues associated with the practicality of applying runway pricing to large loads? What load threshold should be applied?
- Are you aware of any approaches or methods that could be used to extend contingency FCAS cost allocation frameworks to incorporate network events in a way that enhances cost reflectivity?

3.2 The proponent considers contingency size optimisation and runway cost allocation are complementary measures that work together

The proponent considers contingency size optimisation and runway cost allocation work together, as when large generators are curtailed under contingency size optimisation, they are also the times when they are likely to incur the highest FCAS costs under runway pricing. Curtailment, therefore, acts as a form of insurance for these generators and loads, as central dispatch is likely to reduce their output when contingency FCAS costs exceed their wholesale revenue, and the outcome the proponent considers possible under some tail risk scenarios.[39] The proponent offers the following example to illustrate this interaction.

Box 3: Co-optimising contingency size in dispatch provides an insurance value against high runway pricing outcomes.

The proponent identifies the following example to illustrate the interaction: There are three large generators at a much higher output than all other generators. Due to one of a number of possible reasons, two of those generators bid in a way that will dramatically lower their outputs in the next dispatch period. This leads to a dynamic where the one remaining high output generator is essentially "stranded" far above all other generators, incurring more FCAS costs than it may have anticipated. Under this scenario it's often likely that curtailing that largest generator would:

39 Grids Energy, optimising contingency size in dispatch rule change request, p. 3.

1. Save the system money; and
2. Save that generator money.

In effect this curtailment from central dispatch can provide some "insurance" for large generators and loads under a runway pricing cost allocation as they know that in those tail risk scenarios where they're "stranded" well above the next largest unit or exposed to contingency FCAS costs far above their wholesale revenue, it's likely that central dispatch will lower their output.

The Commission notes the insurance value of contingency size optimisation for tail risk runway pricing outcomes and appreciates the risk management value of this relationship. The Commission also notes that the two proposed mechanisms, runway cost allocation and contingency size optimisation, may represent distinct approaches to achieving the same objective and may function as substitutes rather than complements.

According to the proponent, runway cost allocation would likely lead large generators to incorporate their expected contingency FCAS costs into their energy bids. This approach influences dispatch outcomes by internalising the contingency FCAS costs linked to the largest contingency, potentially resulting in more efficient dispatch. Runway cost allocation, therefore, operates as a distributed market mechanism for internalising these costs.

Contingency size optimisation also internalises contingency FCAS costs but does so directly through the dispatch process rather than through participant bidding. This mechanism directly assigns costs to units with the largest contingency sizes, concentrating the financial impact on the largest unit via reduced energy market revenue.

The Commission seeks stakeholder feedback on whether these mechanisms should be viewed as complementary or substitutes for one another, particularly in light of potential interactions if both are implemented concurrently. This issue is a key consideration for the Commission in its decision-making and is explored further in Chapter 4.

Question 4: Do stakeholders consider the two rule changes to be complementary

- Do you consider contingency size co-optimisation and runway FCAS cost allocation to be complementary mechanisms that work together or substitute mechanisms which aim to achieve the same outcomes via different methods?
- What is your understanding of the interactions between these two mechanisms, should they be implemented together?

3.3 What are the benefits of the proposed solution

The Commission seeks stakeholder input on the benefits of the proponent's proposed solutions, being contingency size optimisation implemented together with runway cost allocation. An understanding of these benefits is necessary for the Commission to assess whether a proposed change promotes the NEO. Further discussion on the Commission's assessment framework is provided in Chapter 4.

This section presents the proponent's claims as to potential rule change benefits and seeks stakeholder views on these claims. This feedback will be incorporated into the Commission's analysis to inform the draft determination.

3.3.1 The proponent considers that contingency co-optimisation will enhance market efficiency

The proponents consider that co-optimising the largest credible contingency size in dispatch will increase dispatch efficiency, particularly in circumstances where FCAS costs are high relative to wholesale energy costs. It considers that overall cost savings can be achieved through a reduction in contingency FCAS costs when these costs are larger than other system costs that may increase from curtailing the largest contingency, such as wholesale energy.[40]

It further considers that better managing the size of the largest contingency will put downward pressure on total system costs and allow participants with large generators and loads to bid more efficiently, leading to better price outcomes in the long-term interest of consumers.[41] The proponent provides the following example illustrating the potential efficiency gain from contingency size optimisation.

Box 4: Example illustrating the potential efficiency gain from contingency size co-optimisation

Imagine a simplified situation where central dispatch must procure 500 MW of capacity for wholesale energy dispatch, and it can procure contingency FCAS capacity against its largest contingency at a flat rate of $30/MWh.

In the next 5-minute dispatch, there's one 500MW generator that bids its full capacity into the wholesale market at $14/MWh and five 100MW generators that bid in their full capacity at $15/MWh. None of these generators are bidding any capacity into FCAS.

Solely minimising energy market costs would see the 500MW generator dispatched over the five 100MW units. When contingency FCAS costs are included however, the 100MW units are cheaper.

The following table shows the difference in costs under current arrangements versus a lowest cost solution.

	Current NEMDE solution	Lowest cost solution
Wholesale Costs	$ 583.3 (41.7MWh@$14/MWh)	$ 625 (41.7MWh@$15/MWh)
FCAS Costs	$ 1,250 (41.7MWh@$30/MWh)	$ 250 (8.3MWh@$30/MWh)
Total Costs	**$1,833.3**	**$875**

Table 1 Comparing cost outcomes of the current NEMDE dispatch vs lowest cost dispatch.

3.3.2 The proponent considers that runway FCAS will allocate FCAS fairly and create incentives for more efficient bidding

The proponent considers that runway pricing will decrease contingency FCAS volumes thereby reducing contingency FCAS prices. This in turn should lower total system costs leading to lower power bills.[42] They note that it may also promote system resilience, as larger single credible

40 Grids Energy, optimising contingency size in dispatch rule change request, p. 3.
41 Ibid, p. 6.
42 Grids Energy, allocating contingency FCAS costs rule change request, p. 10.

contingencies can mean larger rates of change of frequency, even if you procure enough FCAS for that contingency.[43]

Runway pricing more strongly encourages a lower output of the largest generator or load in both the short term (through operational decisions) and long term (through investment decisions), which lower the amount of contingency FCAS volumes required (at times when a network element is not the largest contingency) placing downward pressure on contingency FCAS costs. The runway cost allocation rule change then discusses short and long run benefits.

Short-run benefits from more efficient bidding - The proponent considers that runway cost allocation would incentivise generators and loads to make offers for energy in a way that considers the contingency FCAS costs they could incur as a result of being dispatched in the energy market. An example of this is that currently, when the largest generation/load source increases or decreases its output, most of the FCAS costs or savings are borne by the other generators. The proponent therefore considers that runway pricing would concentrate a larger proportion of the cost or saving onto the largest generator and therefore each participant's costs would be more correlated to their own output and less to the largest generation or load source's output.[44] Runway pricing therefore better allocates risk (i.e., the potential costs and savings) onto the parties that can best manage that risk (i.e., large generators or loads whose outputs dictate the volume of contingency reserves required).

The proponent anticipates that short-run benefits with participants expected to predict the likely cost impact of their share of contingency FCAS costs and incorporate this in their offers for energy. Runway pricing more strongly encourages a lower output of the largest generator or load in the short term through operational decisions which lower the amount of contingency FCAS volumes required, placing downward pressure on contingency FCAS costs.[45]

Long run benefits from more efficient investment decisions – The proponent considers runway pricing also provides better incentives for investors to consider the additional contingency FCAS costs their investment may impose on the system.[46] The runway pricing rule change request provides an example illustrating the commercial incentive for investors to consider unit size, given the commercial incentives from runway cost allocation.

The proponent then considers it important to highlight the following:[47]

- The incentive to split up generators or loads is non-linear, so it becomes material once the generator or load size approaches and exceeds the current or future largest contingency (i.e., when it's likely to impose extra system costs), but would be insignificant at the smaller scales.
- Runway pricing doesn't ban the building of large generators or loads, merely that where they impose additional costs on the system, they are the ones that would bear the cost. The current arrangements mean that participants or investors developing large scale generators and loads can largely ignore these additional system costs as they are overwhelmingly distributed to other participants in the system.
- The proposed approach is preferable to inflexible approaches to limit the size of the largest allowable unit connection. Rather, runway pricing would provide a flexible arrangement that would adapt to changes in the power system and encourage market participants to consider the operational contingency reserve costs due to their development.

43 Ibid, p. 9.
44 Grids Energy, allocating contingency FCAS costs rule change request, pg 10.
45 Ibid, p. 8.
46 Ibid, p. 9.
47 Grids Energy, allocating contingency FCAS costs rule change request, pg 8.

The Commission appreciates how the proponent considers runway contingency FCAS cost allocation would create short-run and long-run benefits. The Commission however considers that participants would also need to be able to sufficiently act on these signals which would need to be sufficient in magnitude to change participant bidding and investment behaviour to achieve the benefit identified. The Commission seeks stakeholder views on the extent to which participant bidding is likely to change given the runway cost allocation to achieve the benefits identified by the proponent.

Question 5: Do stakeholders agree with the benefits identified from contingency size optimisation and runway FCAS cost allocation

- Do you agree that participant bidding is likely to change, given the runway cost allocation to achieve the benefits identified by the proponent?
- Do you agree that contingency size optimisation will enhance market efficiency as identified by the proponent?

3.4 What are the costs and risks of the proposed solutions

The Commission seeks stakeholder input on the costs and risks of the proponent's proposed solutions. An understanding of these costs and risks is necessary for the Commission to assess whether a proposed change promotes the NEO. Further discussion on the Commission's assessment framework is provided in Chapter 4.

This section presents the proponent's claims on potential costs and risks and seeks stakeholder views on these claims, which the Commission will then use to inform its assessment.

3.4.1 AEMO would face direct costs from the NEMDE changes required to implement contingency size optimisation

The proponent identifies direct costs for AEMO to amend its dispatch systems to implement an obligation to optimise contingency sizes that is proposed in the contingency size optimisation rule change.[48]

Contingency size optimisation would be implemented into central dispatch, which would require changes to the National Electricity Market Dispatch Engine (NEMDE). The proponent accepts that there are likely significant costs associated with changing NEMDE and that these costs may limit the scope of the potential solution.[49]

In light of these potential costs, the proponent considers that a partial implementation may be appropriate as well as the use of rules of thumb to reduce the implementation burden.[50] Based on these properties, there may be simple, initial implementations that achieve some curtailment outcomes (and miss others), where improvements can be made over time if it is cost-effective to do so.

The Commission understands that AEMO's current practice is to move the output of the largest unit in a region to the LHS on a case by case basis when the conditions identified in section 2.2.1

48 Grids Energy, allocating contingency FCAS costs rule change request, pg 4.
49 Ibid, p. 4.
50 Ibid, p. 5.

are met.[51] We understand that this is currently a manual process which relies on the unit representing the largest contingency to be identified beforehand in order for the relevant constraint to be adjusted. However, as the identity of the largest contingency may not be known before the dispatch process is run, a general obligation to optimise contingency size to achieve market benefits, may require individual FCAS constraint equations to be written for each large unit across the NEM. This might involve significant costs and practical constraints on the solution that can be beneficially implemented. In light of these costs, the proponent suggested exploring partial solutions until a time where it does bewhencome feasible to fully implement this mechanism.[52]

Given these potential costs and implementation issues, the Commission seeks stakeholder input on the costs associated with implementing a general obligation to co-optimise contingency size in dispatch for AEMO's dispatch?

3.4.2 There are potential on long run market efficiency costs from contingency size co-optimisation

In addition to the direct implementation costs for AEMO's systems, the proponent identifies a potential for contingency size optimisation to impact market integrity.[53] Their proposal specifically includes a provision for the implementation of contingency size optimisation to be limited to circumstances where these interventions would not lead to long-run costs (such as a reduction in the long-run efficiency of bids or loss of investor or participant confidence) that outweigh the benefits of the interventions.[54]

The proponent then provides contract market liquidity as an example of a market integrity issue that may arise. According to the proponent, the potential for curtailment may result in a decrease in generator willingness to offer caps and swaps into the contract market, which may reduce contract market liquidity as large thermal generators currently serve as the primary suppliers of these products.[55] The proponent provides the following example to illustrate this risk.

Box 5: Contingency size optimisation and risks to contract market liquidity

The proponent proposes an example that demonstrates this is during high wholesale price events. If there is a large generator that sold $300 caps against its output, and is curtailed to reduce the largest contingency, that may impose a very large cost on the generator due to its commercial arrangements. Additionally, even without the cap the generator would still forego revenue in these situations. A consequence of this may be that large generators sell less caps or are less investable due to the uncertainty of potentially being curtailed under this mechanism, which could lead to negative long-term impacts that outweigh the cost savings that are achieved in these scenarios.

Negatively impacting contract market liquidity can have flow-on effects including to reduce the efficiency of longer-term price discovery. This has implications for investment decision-making as lower contract market liquidity can affect the ability of new generators to secure contracts that enable financing. Lower liquidity could also affect the ability of new retail market entrants to secure contracts, thereby reducing retail market competition and innovation. The Commission will consider the potential for market integrity risks carefully in its assessment. Further discussion is provided in Chapter 4, and seeks stakeholder input on the materiality of these potential risks.

51 AEMO implements contingency size co-optimisation by moving the output of the largest unit to the left hand side (LHS) of the generic constraint equations that ensure sufficient enablement of contingency FCAS. This would make the output of the largest unit a dependent variable in the FCAS constraint equations.

52 Ibid, p. 5.

53 Grids Energy, allocating contingency FCAS costs rule change request, pg. 3.

54 Ibid p. 2.

55 Ibid, p. 3.

3.5 How will the changes associated with the transition affect costs and benefits over time

The Commission is interested in stakeholder views on how the benefits, costs, and risks may change over the course of the transition. This is consistent with the Commission's role to assess the long-term benefits for consumers from any rule change.

The Commission is aware of a range of changes occurring that will change the system security risk profile in the NEM relevant to arrangements for, and the costs of, contingency FCAS. A number of macro changes are identified below that the Commission intends to investigate further when assessing the long-term benefits, costs and risks as part of its NEO assessment.

- Thermal generation units have historically been amongst the largest contingencies that have determined the amount of raise contingency FCAS required. Thermal coal generation units are progressively closing. AEMO's generation dataset lists Kogan Creek, which is the largest thermal coal generator in the NEM as expected to close in 2035. Given this, the significance of individual generation unit contingencies is likely to decline over the course of the transition, potentially reducing the value and benefit of runway pricing and contingency size optimisation of these units over time.
- By contrast, the Commission is aware of increasingly large loads seeking connection in the NEM, in particular the potential for very large data centre loads, which may see an increase in contingency lower services to manage the related contingency risk. The value of cost-reflective arrangements for load events may increase over the course of the transition, along with associated benefits.
- The most significant driver of non-load-related contingency events is likely to remain network-related. While the risk of inter-regional separation, which is a current driver of high contingency FCAS prices and costs, will likely decline with increasing interconnection, the implementation of multi-GW renewable energy zones may represent the largest generation contingency sizes in the future.
- If the costs of contingency FCAS continue their structural decline, given the capacity of large BESS that is anticipated to connect into the NEM, can we expect contingency FCAS costs to remain sufficiently low to negate the benefits from the package of rule changes.

The Commission is interested in stakeholder views and insights on these trends and how they relate and influence the costs, benefits, and risks of the package of rule changes proposed by the proponent.

Question 6: What are your views on the costs, benefits, and risks of the proposed solution

- Do you agree with the costs and benefits of the package of proposed rule changes as put forward by the proponent?
- Do you have any insights on how the costs and benefits of the proposal may change given the transitioning power system?
- Do you consider the market integrity risks identified by the proponent in respect of contingency size optimisation to be material and how should the best be managed should the rule be made?
- How do you see the change in the contingency risk profile of the NEM affecting costs and benefits over the course of the transition?

4 Making our decision

When considering a rule change proposal, the Commission considers a range of factors.

This chapter outlines:

- issues the Commission must take into account
- the proposed assessment framework
- key assessment considerations
- decisions the Commission can make
- rule-making for the Northern Territory

We would like your feedback on the proposed assessment framework.

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

The Commission is bound by the National Electricity Law (NEL) to only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the National Electricity Objective.[56]

The NEO is:[57]

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

4.2 We propose to assess the rule change using these three criteria

4.2.1 Our methods to analyse the proposed rule

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

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

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

56 Section [88 of the NEL].
57 Section 7 of the NEL.

4.2.2 Assessment criteria and rationale

The proposed assessment criteria and rationale for each is as follows:

- **Safety, Security, and Reliability** - The rule change requests relate to the way in which dispatch minimises certain risks to system security, in particular, the size of the largest credible contingency. The Commission will also consider the impacts on system security in considering these rule changes. It will consider whether the aim of the rule change will enhance system security by limiting the size of the largest credible contingency and therefore the size of the disturbances the system must remain secure to.
- **Principles of market efficiency** - The proponent views these rule changes as providing a market efficiency benefit by directly minimising the amount and costs of FCAS required, and internalising FCAS costs into market processes through better signals for operation and investment. The Commission will consider the efficiency benefits that could be created if the changes were to be made. The Commission intends to assess the extent to which the rule changes would lead to different dispatch outcomes and, therefore, costs relative to outcomes under existing arrangements.
- **Implementation considerations** - The rule changes have implementation considerations from the necessary changes in AEMO's systems as well as the potential impact on the pace of the transition, should the reduction in dispatch lead to earlier thermal retirements or reductions in contract market liquidity. The Commission will consider implementation costs to both AEMO and industry more broadly as part of its considerations. It intends to work with AEMO to appreciate the required systems changes and associated costs as well assess potential contract market liquidity impacts arising from the rule change's incentives

Question 7: Assessment framework

Do you agree with the proposed assessment criteria? Are there additional criteria that the Commission should consider or criteria included here that are not relevant?

4.3 Key assessment considerations

This is the section where we identify a number of key considerations relevant to our assessment of the proposed rule changes against the NEO, which we are interested in stakeholder feedback on.

4.3.1 Is a rule change required to achieve benefits

Clause 3.15.6A of the National Electricity Rules (NER) outlines the arrangements for contingency Frequency Control Ancillary Services (FCAS) cost recovery. A rule change is therefore required to implement runway contingency FCAS cost allocation as requested by the proponent.

We understand that AEMO already co-optimises contingency size in dispatch in certain circumstances under its system security responsibilities as described in Chapter 2. The rule change proponent seeks to broaden AEMO's current approach to contingency size co-optimisation to achieve market benefits, beyond its existing system security focus. The Commission will assess whether the proposed rule change's objectives can be met under current arrangements and whether a non-rule change approach could be adopted, either temporarily or permanently, to inform the need for further rule changes.

In evaluating the proposal, the Commission will consider whether the expected benefits justify imposing additional obligations on AEMO, taking into account the associated regulatory and implementation costs and risks.

4.3.2 Whether the scope of the rule change should also consider expanding the FCAS framework to network events

Current arrangements for contingency FCAS cost allocation exclude network events, despite their significant role in driving contingency FCAS costs. While the proponent did not explicitly propose that the rule change incorporate network events, they raised the question of whether FCAS cost recovery arrangements should be broadened to account for the impact of network events.

The Commission's initial view is that including network events in FCAS cost recovery, in a way that enhances cost reflectivity, would involve substantial implementation complexity. As outlined in Chapter 3, imposing a simple obligation on networks to pay would likely shift a greater share of contingency FCAS costs onto consumers. This outcome would not improve cost reflectivity as customers individually are not individually causers of contingency FCAS requirements. Alternatively, allocating costs to specific generators and loads contributing to the flows associated with the largest credible network contingency, may involve a level of complexity that isn't justified by the potential benefits.

For these reasons, the Commission is not minded to expand the scope of FCAS cost allocation to include network events at this time. However, it will seek stakeholder feedback on potential approaches for incorporating network events if consultation reveals a credible case for further examination.

4.3.3 Whether increasing financial risk via runway pricing also has market integrity risks

The proponent identifies a set of market integrity risks arising from contingency size optimisation. The Commission will also consider whether runway pricing creates additional market integrity risks. Runway pricing concentrates financial exposure on the unit that represents the largest credible load or generation contingency. This concentration increases the unit's financial risk. The Commission notes that higher financial risk can raise investment risk premiums. Inter-regional separation events that drive contingency FCAS costs exhibit tail-risk characteristics, so contingency FCAS costs can spike unpredictably and materially, increasing cost volatility for affected units.

Allocating higher financial risk can produce beneficial outcomes when the market assigns that risk to the participant best able to manage it. Participants contract to hedge against price spikes in the wholesale electricity market. This is possible as load and generators are natural counterparties. Participants, however, lack natural counterparties to hedge exposure to contingency FCAS costs, so large units face additional, largely unhedgeable financial exposure when contingency FCAS costs rise. This exposure will fall most heavily on the large units. Higher levels of financial risk also have implications for the NEM's prudential arrangements and may lead to a higher risk of margin calls on market participants following a spike in contingency FCAS costs.

The Commission will assess whether affected units can effectively manage the additional financial risk associated with runway pricing through operational measures or other mechanisms. The Commission will also examine whether the proposed allocation could distort investment incentives or market behaviour relevant to market integrity considerations.

4.3.4 Whether contingency size co-optimisation and runway cost allocation are complementary mechanisms or substitute mechanisms

The proponent argues that both rule changes should operate together to improve the efficiency of the contingency FCAS framework.

The Commission will examine the interaction between the two rule changes and whether both are necessary to increase efficiency. More cost-reflective FCAS cost allocation is likely to encourage participants to incorporate expected FCAS costs into their bids, which should allow the market to internalise FCAS costs in dispatch and yield a more efficient outcome through a decentralised, market-based approach.

Given that effect, the Commission will consider whether contingency size optimisation is necessary. Contingency size optimisation aims to deliver a similar efficiency outcome but through adjustments to the centralised market mechanism.

If both measures pursue the same objective by different mechanisms, the Commission considers it may be preferable to identify a single approach to avoid implementing two overlapping solutions unless significant co-benefits of implementing both contingency size optimisation and runway pricing are identified.

4.4 We have three options when making our decision

After using the assessment framework to consider the rule change request, the Commission may decide:

- to make the package of rule changes as proposed by the proponent. [58]
- to make a rule that is different to the proposed rule (a more preferable rule), as discussed below, or
- not to make a rule.

The Commission may make a more preferable rule (which may be materially different to the proposed 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.[59]

4.5 The proposed rule would not apply in the Northern Territory

Parts of 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.[60]

The proposed rule would not apply in the Northern Territory, as it amends provisions in NER Chapter 3 that do not apply in the Northern Territory.[61] Consequently, the Commission will not assess the proposed rule against additional elements required by the Northern Territory legislation.

58 The proponent sets out its proposed rule in sections 5 of the Allocating contingency FCAS costs rule change request, and section 3 of the optimising contingency size in dispatch rule change request.

59 Section 91A of the NEL.

60 National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 (**NT Act**). The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016.

61 Under the NT Act and its regulations, only certain parts of the NER have been adopted in the Northern Territory. The version of the NER that applies in the Northern Territory is available on the AEMC website at: https://energy-rules.aemc.gov.au/ntner.

Abbreviations and defined terms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
Commission	See AEMC
FCAS	Frequency Control Ancillary Services
LHS	Left Hand Side
MW	Mega Watt
MWh	Mega Watt Hour
NEMDE	National Electricity Market Dispatch Engine
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
PFR	Primary Frequency Response
Proponent	The proponent of the rule change request
WEM	Western Australian Wholesale Energy Market