RELIABILITY PANEL AEMC

DETERMINATION

Reliability Panel AEMC

FINAL DETERMINATION

REVIEW OF THE FREQUENCY OPERATING STANDARD

6 APRIL 2023

INQUIRIES

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Reference: REL0084

CITATION

Reliability Panel, Review of the Frequency operating standard, 6 April 2023

ABOUT THE RELIABILITY PANEL

The Panel is a specialist body established by the Australian Energy Market Commission (AEMC) in accordance with section 38 of the National Electricity Law and the National Electricity Rules. The Panel comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on reliability, security and safety on the national electricity system, and advising the AEMC in respect of such matters.

RELIABILITY PANEL MEMBERS

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SUMMARY

1 The Reliability Panel (Panel) has determined to revise the frequency operating standard (FOS) to adapt to the changing nature of the power system. The revised FOS which, will commence on **9 October 2023**, specifies the expected frequency outcomes for the electricity system in the National Electricity Market (NEM). This determination will help promote the National Electricity Objective (NEO) by managing the trade-off between the benefits of a secure and resilient power system and the costs of achieving this, so promoting the long-term interests of consumers.

2 The FOS specifies the required system frequency outcomes that AEMO must meet under different conditions. The Panel considers that the additions and amendments to the FOS are crucial to cost-effectively maintaining system security in the rapidly transitioning power system.

3 Stable operation of the power system requires that frequency be maintained close to a nominal target of 50 Hz. This frequency is essentially a measure of the speed of rotating machinery connected to the power system. When generation is equal to load, the frequency will be stable. However, when there is a mismatch between instantaneous demand for electricity and the power supplied by generators, system frequency will diverge from 50 Hz.

4 Power system equipment, including generators, load and associated plant may disconnect from the power system if the system frequency becomes unstable and changes too quickly, or varies too far from 50 Hz. This can result in the separation of regions from the NEM, disconnection of load and, in the worst cases, the collapse of all or part of the power system causing a system black and loss of supply to consumers.

5 The transformation and decarbonisation of the power system presents challenges and opportunities for the control of power system frequency. The reduction in synchronous thermal generation is expected to result in reduced levels of inertia that acts to resist changes in power system frequency and keep the grid stable. At the same time, new inverter-connected technologies, including renewable generation and battery energy storage systems have the capability to provide very fast active power response to changes in system frequency, if they are configured to do so. The revised FOS provides a basis for ongoing work by the market bodies to maintain system security and continue to integrate new technologies to build the power system of the future.

The core elements of the revised FOS

6 The key elements of the revised FOS, are:

- the introduction of system limits for rate of change of frequency (RoCoF) following contingency events
- changes to the settings that relate to the limits and thresholds for contingency events
- changes to the FOS that applies during system restoration following a major system disturbance

- confirmation of the allowable ranges for frequency during normal operation, the primary frequency control band (PFCB) and that the target frequency is 50 Hz
- the removal of the limit for accumulated time error.

7 The revised FOS is largely consistent with the draft FOS, with the exception of the following additional changes made in response to stakeholder feedback to the draft determination:

- The minimum threshold for a generation event in Tasmania is revised to 20MW to align with the threshold for a load event in Tasmania.
- The operational frequency tolerance band (OFTB) during system restoration is revised from 48 – 52 Hz to 49 – 51 Hz.

8 The revised FOS will take effect from **9 October 2023.** This aligns with the commencement of the new market ancillary service arrangements for very-fast contingency FCAS i.e. two new markets to provide fast frequency response.

System limits for Rate of Change of Frequency following contingency events.

9 Consistent with the draft FOS, the revised FOS includes new requirements for the allowable RoCoF following credible and non-credible contingency events. This new element of the standard defines the system operating limits in the face of the expected reduction in inertia provided by synchronous generators as the generating fleet becomes increasingly dominated by inverter-based renewable generation. The revised FOS includes separate RoCoF requirements for the mainland and for Tasmania. This reflects the different operational characteristics in each of these asynchronous regions. The revised FOS requires that:

- following a credible contingency event, RoCoF must not be greater than:
  - **Mainland**: ±1Hz/s (measured over any 500ms period)
  - **Tasmania**: ±3Hz/s (measured over any 250ms period).
- following a non-credible contingency event, or multiple contingency event that is not a protected event, AEMO should use reasonable endeavours to maintain RoCoF within:
  - **Mainland**: ±3Hz/s (measured over any 300ms period)
  - **Tasmania**: ±3Hz/s (measured over any 300ms period).

10 The Panel considers that the RoCoF limits in the revised FOS are an initial step and will inform further regulatory reforms with the goal of developing market and regulatory arrangements for the efficient provision of inertia and RoCoF control services, such as the rule change request that the AEMC is currently considering on the efficient provision of inertia. The Panel expects that the initial RoCoF limits set out in the revised FOS could be increased in the future, subject to confirmation of increased RoCoF withstand capability of the generation fleet. The Panel will monitor related power system developments and report its findings through its Annual market performance review process. A follow-up review of the FOS is recommended to be completed by no later than the end of 2027. This will allow the Panel to reassess the RoCoF limits in the FOS in light of changes in the power system.

Limits and thresholds on contingency events

11 Consistent with the draft FOS, the revised FOS includes a number of changes to limits and

thresholds for contingency events including:

- extending the existing 144MW limit for generation events in Tasmania to also apply for load and network events
- no limit in the FOS for the maximum size of contingency events in the mainland.

12 In response to feedback from AEMO on the draft determination, the Panel has also determined that the minimum threshold for a generation event in Tasmania be revised to 20MW in line with the threshold for a load event in Tasmania.

The FOS during system restoration

13 The revised FOS includes changes that relate to the standard that applies during restoration of load following load-shedding in the mainland power system or an island that has formed following separation from the mainland power system.

14 In response to feedback from AEMO, this element of the revised FOS differs from the approach set out in the draft FOS. The revised FOS includes:

- Drafting changes that clarify that this element of the standard — Table A.5 — applies for the operation of an interconnected system or an island, where load is being restored following automatic load disconnection in response to a contingency event. This change better reflects the purpose of this element of the standard which is to accelerate the reconnection of load following a significant system disruption.
- That the operational frequency tolerance band (OFTB) during system restoration be revised from 48 – 52 Hz to 49 – 51 Hz. This change resolves an inconsistency identified in the FOS and standardises the OFTB across all expected modes of system operation. As a result of this change, the frequency withstand performance requirements for connecting generators in accordance with clause S5.2.5.3 of the Rules will be aligned with the expected system frequency outcomes in the FOS.

The settings for frequency performance during normal operation

15 The revised FOS maintains the current allowable ranges for frequency during normal operation through the normal operating frequency band (NOFB) and the normal operating frequency excursion band (NOFEB). It also confirms the primary frequency control band (PFCB) as 49.985 – 50.015 Hz, consistent with the current setting in the NER. The PFCB relates to the sensitivity for the provision of mandatory primary frequency response (PFR).

16 The FOS also confirms that the target frequency for the power system is 50 Hz, consistent with the engineering assumptions that underpin the power system.

17 This element of the Panel's determination is supported by advice from AEMO and the results of power system modelling undertaken by GHD which shows that provision of narrow band PFR by the bulk of the generation fleet delivers effective control of system frequency, increased power system resilience and reduced aggregate costs for frequency control.

18 The Panel is aware of a wide range of stakeholder views in relation to the settings in the FOS that apply during normal operation and the interaction of these with the PFCB that relates to the sensitivity for mandatory PFR provided by scheduled and semi-scheduled generators. The

Panel considers that the settings determined in the FOS are necessary and appropriate under the current market and regulatory arrangements, where there is a reliance on mandatory PFR to deliver effective frequency control and there are no other tools at AEMO's disposal to adjust the level of aggregate frequency responsiveness in response to the changing system needs over operational time frames.

19 The Panel notes that new frequency performance payment arrangements will commence on 8 June 2025. These new arrangements are expected to incentivise the provision of PFR beyond and in addition to the mandatory requirement. They will also provide a mechanism to allow AEMO to influence the level of aggregate frequency responsiveness provided by power system plant. The Panel recommends a subsequent review of the settings in the FOS for normal operation at a future date. This future review could account for learnings from AEMO's reporting on aggregate frequency responsiveness, which commenced in Q3 2022, and operational experience with the new frequency performance payments.

Removal of a quantified limit on accumulated time error

20 The Panel has determined to remove the limit on accumulated time error from the FOS. This provides AEMO with greater flexibility to adjust its systems and procedures as required, while maintaining the existing reporting requirements through its weekly and quarterly frequency performance reports.

The Panel's determination is informed by stakeholder feedback and expert advice

21 The revised FOS addresses the issues raised in the terms of reference provided to the Panel by the AEMC and responds to stakeholder feedback to the issues paper and draft determination. The Panel's draft and final determinations were informed by technical advice provided by AEMO as required under clause 8.8.1(a)(2) of the NER and independent analysis and advice provided by GHD. Further detail on the consultation and policy development process for the review is provided in appendix A.

The Panel recommends that a subsequent review of the FOS be completed by no later than the end of 2027

22 The Panel recommends that a subsequent review of the FOS be completed by no later than the end of 2027. The scope of this subsequent review should include further consideration of:

- the settings in the FOS for rate of change of frequency — taking account of system and regulatory development in the interim period
- the settings in the FOS for normal operation — taking account of the market and system impacts stemming from the commencement of new frequency performance payment arrangements on 8 June 2025.

23 This timing would allow for a period of 12 – 18 months to monitor the impacts of the frequency performance payments arrangements and inform further consideration of the PFCB and the settings in the FOS for normal operation.

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APPENDICES

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1 THE PANEL HAS MADE A FINAL DETERMINATION

The Reliability Panel is responsible under the National Electricity Rules (the Rules) for determining the power system security standards, including the frequency operating standard (FOS). This final determination is to update the FOS which applies to the national electricity system, including the NEM mainland and Tasmania.[1]

The Panel's determination has been informed by stakeholder submissions along with technical advice provided by AEMO as required under clause 8.8.1(a)(2) of the Rules and independent analysis and advice provided by GHD. Further detail on the consultation and policy development process for the review is provided in appendix A.

The revised FOS is largely consistent with the draft FOS, with the exception of some changes made in response to stakeholder feedback on the draft determination.

The Panel's assessment against the assessment criteria and the NEO is set out in chapter 2. A mark-up copy and a clean copy of the revised FOS have been published separately on the project webpage. The revised FOS will take effect from 9 October 2023, aligning with the commencement of the new market ancillary service arrangements for very-fast FCAS i.e. fast frequency response.

This chapter provides:

- Section 1.1 — an overview of the changes in the revised FOS and the high-level reasoning for these
- Section 1.2 — a summary of how stakeholder feedback has shaped the revised FOS
- Section 1.3 — an overview of the interactions between this determination and other current and upcoming market reforms.

1.1 Overview of the revised FOS

This section summarises the key features of the revised FOS. It outlines:

- Section 1.1.1 — the introduction of system limits for RoCoF following contingency events
- Section 1.1.2 — changes to the settings that relate to the limits and thresholds for contingency events
- Section 1.1.3 — changes to the FOS that applies during system restoration following a major system disturbance
- Section 1.1.4 — the settings for the expected frequency outcomes for normal operation and the PFCB that relates to the sensitivity of mandatory PFR provided by scheduled and semi-scheduled generators
- Section 1.1.5 — the removal of the limit on accumulated time error.

1 The national electricity system comprises the combined electricity grids for Queensland, New South Wales, Victoria, South Australia and Tasmania. The electricity systems for Western Australia (SWIS) and the Northern Territory are operated separately and are not covered by the NEM FOS.

1.1.1 The introduction of post-contingency RoCoF limits

Consistent with the draft FOS, the revised FOS includes new requirements for how AEMO manages the rate of change of frequency following credible and non-credible contingency events. These new elements of the FOS define the safe operating envelope for the power system in the context of the ongoing reduction in system inertia due to the progressive retirement of synchronous thermal generators. In the short term, the specification of limits for RoCoF would support the implementation of the new market ancillary service arrangements for fast frequency response services (very fast raise and very fast lower services). Over the longer term, these limits will also support the development of future arrangements to provide RoCoF control services including through synchronous and synthetic inertia. As such, this change to the FOS will assist with the valuation and procurement of essential system services to manage post-contingency RoCoF, thereby supporting efficient investment in and operation of energy resources.

As described in section 1.2.1, stakeholder responses to the consultation paper and draft determination were generally supportive of the inclusion of limits for post contingency RoCoF. At the same time, the Panel acknowledges requests for further detail on how the RoCoF arrangements will be operationalised and adapted over time to avoid locking the system in to a high inertia/low RoCoF paradigm. The Panel considers that the RoCoF limits in the revised FOS are an initial step and will inform further regulatory reforms with the goal of developing market and regulatory arrangements for the efficient provision of inertia and RoCoF control services, such as the rule change request that the AEMC is currently considering relating to the efficient provision of inertia. The Panel expects that the initial RoCoF limits set out in the revised FOS could be increased in the future subject to confirmation of increased RoCoF withstand capability of the generation fleet.

RoCoF requirements for the mainland

Following a credible contingency event, RoCoF must not be greater than ±1Hz/s (measured over any 500ms). This value is driven by AEMO's assessment of the RoCoF ride-through capability of legacy plants within the current generation fleet and is consistent with the findings from GHD's survey of international approaches to RoCoF management.[2]

Following a non-credible contingency event or multiple contingency event that is not a protected event, AEMO should use reasonable endeavours to maintain RoCoF within ±3Hz/s (measured over any 300ms). This value aligns with the range of RoCoF that supports the satisfactory operation of emergency frequency control schemes in the mainland NEM, based on technical advice and analysis provided by AEMO.

RoCoF requirements for Tasmania

Following a credible contingency event, RoCoF must not be greater than ±3Hz/s (measured over any 250ms). This value is driven by AEMO's assessment of the RoCoF withstand capabilities of the predominantly hydroelectric powered Tasmanian grid. AEMO's advice

2 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.24.; GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, pp.30-31

confirms that hydroelectric generators have much greater RoCoF ride-through capability when compared to thermal generators.

Following a non-credible contingency event or multiple contingency event that is not a protected event, AEMO should use reasonable endeavours to maintain RoCoF within ±3Hz/s (measured over any 300ms). This value aligns with the existing dynamic UFLS approaches implemented in Tasmania. Advice provided by AEMO and TasNetworks supports the introduction of these limits that try to compensate for the complexities of safely operating the Tasmanian network.

Further detail on this element of the FOS is included in chapter 3.

1.1.2 Limits and thresholds on contingency events

Consistent with the draft FOS, the revised FOS includes a number of changes that relate to limits and thresholds for contingency events including:

- extending the existing 144MW limit for generation events in Tasmania to apply to load and network events
- no limit in the FOS for the maximum size of contingency events in the mainland.

In response to feedback from AEMO on the draft determination, the Panel has also determined that the minimum threshold for a generation event in Tasmania be revised to 20MW to align with the threshold for a load event in Tasmania.

An overview of these elements in the revised FOS is provided below.

Extension of the limit on the size of credible contingency events in Tasmania

The revised FOS extends the existing 144MW limit for generation events in Tasmania to apply to load and network events. Supported by advice from AEMO, this change reflects the particular challenges associated with operating the Tasmanian power system including its relative small size and the scarcity of fast-acting contingency reserves.[3] TasNetworks proposed the extension of the limit on the largest contingency event to help manage the risks associated with the connection of large commercial and industrial loads, such as hydrogen electrolysers and large-scale data centres.[4]

The extension of the existing 144MW limit to cover all types of credible contingency events in the Tasmanian region provides a consistent and transparent indication of the safe operating range for the Tasmanian power system. Given the particular operational challenges for the Tasmanian region, this element of the revised FOS aligns with operational practices in Tasmania and will provide transparency as to the hosting capacity of the Tasmanian grid for both generation and load connection applications.

The revised minimum threshold for a generation event in Tasmania

The Panel has determined to revise the minimum threshold for a generation event in Tasmania down to 20MW, in line with the threshold for a load event in Tasmania. As noted in

3 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.51.

4 TasNetworks, submission to the issues paper, p.5.

AEMO's submission to the draft determination, this change will better reflect the specific operating conditions in the Tasmania system, including a different mix of generation technologies, a significantly smaller power system with lower inertia, a relative scarcity of FCAS volume, and the significant impact of Basslink as both a generation source and a load.[5]

No requirement to limit the size of contingency events in the mainland

The revised FOS does not include a limit on the maximum allowable credible contingency event in the mainland. While AEMO is expecting a range of potential future developments in the mainland power system that have the potential to test the hosting capacity of the mainland grid, its advice is that a limit on the maximum size of a credible contingency in the FOS is not justified at this time. In its advice, AEMO noted that it may be difficult for the specification of a limit in the FOS to adequately reflect the geographical variation of the network hosting capacity and how this may change over time. AEMO's view is that it may be more appropriate for operational issues related to the connection of large generators and loads to be managed by AEMO and TNSPs directly.[6]

The Panel agrees with AEMO and the AEC's suggestion that AEMO and TNSPs could provide greater transparency for connecting participants through the publication of a document outlining network hosting capabilities and contingency size limits and would encourage these parties to do so.[7]

Further detail on this element of the FOS is included in chapter 4.

1.1.3 The FOS during system restoration

The revised FOS includes changes that relate to the standard that applies during restoration of load following load-shedding in the mainland power system or an island that has formed following separation from the mainland power system.

In response to feedback from AEMO, this element of the revised FOS differs from the approach set out in the draft FOS. The revised FOS includes:

- Drafting changes that clarify that this element of standard — Table A.5 — applies for the operation of an interconnected system or an island, where load is being restored following automatic load disconnection in response to a contingency event. The drafting in the revised FOS has been amended to better reflect the purpose of this element of the standard which is to accelerate the reconnection of load following a significant system disruption.
- That the operational frequency tolerance band (OFTB) during system restoration be revised from 48 – 52 Hz to 49 – 51 Hz. As noted in AEMO's submission to the draft determination, this change will standardise the OFTB across all expected modes of system operation and resolve an inconsistency that arises from the current settings

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

6 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.52.

7 AEC, submissions to the draft determination, p.4; AEMO, Advice for the Reliability Panel's Review of the Frequency Operating Standard, 8 December 2022, p.52.

whereby connecting generators must demonstrate a withstand capability that exceeds the expected system frequency outcomes.[8]

Further detail on this element of the FOS is included in chapter 5.

1.1.4 The settings for frequency performance during normal operation

The Panel has reviewed the settings in the FOS that apply for normal operation — in the absence of contingency events — and the setting for the primary frequency control band (PFCB) that relates to the sensitivity of PFR provided by scheduled and semi-scheduled generators in the NEM. Consistent with the draft FOS, the revised FOS:

- Includes a new requirement that the target frequency in the NEM is 50 Hz. This aligns with one of the fundamental principles for operation of the power system and reflects AEMO's operational practises.
- Maintains the current settings for the allowable range of frequency during normal operation. For interconnected operation in the mainland and Tasmania:
  - the normal operating frequency band (NOFB) is maintained as 49.85 – 50.15 Hz
  - the normal operating frequency excursion band (NOFEB) is maintained as 49.75 – 50.25 Hz.
- Sets the PFCB at 49.985 – 50.015 Hz. This is consistent with the initial setting for the PFCB in the NER.

The Panel notes the range of stakeholder views on this element of the FOS, including concerns expressed by generator representatives on the process and outcomes relating to the settings in the FOS for normal operation. An overview of this element of the FOS is provided below and further detail is included in chapter 6.

Consistent with stakeholder responses to the issues paper, the key focus of the Panel's consideration for this element of the FOS has been the analysis of the costs and benefits associated with different settings for the PFCB that directly relates to the expected range of power system frequency during normal operation. The Panel's determination is informed by advice from AEMO and detailed power system modelling undertaken by GHD to study the operational and economic impacts associated with varying the PFCB.

A narrow setting for the PFCB delivers improved power system resilience

The Panel's final determination is supported by advice from AEMO that the existing settings for the PFCB and normal operation are necessary to maintain effective control of frequency that is fundamental to a secure and resilient power system. Analysis undertaken for the Panel by GHD provides further evidence that narrower settings for the PFCB are expected to deliver a more secure and resilient power system. This increase in system resilience due to narrow PFCB settings is demonstrated through expectations for reduced load shedding following significant non-credible contingency events, and a significant increase in the likelihood of resynchronisation for islanded regions following such separation events.

8 AEMO, submission to the draft determination, p.2.

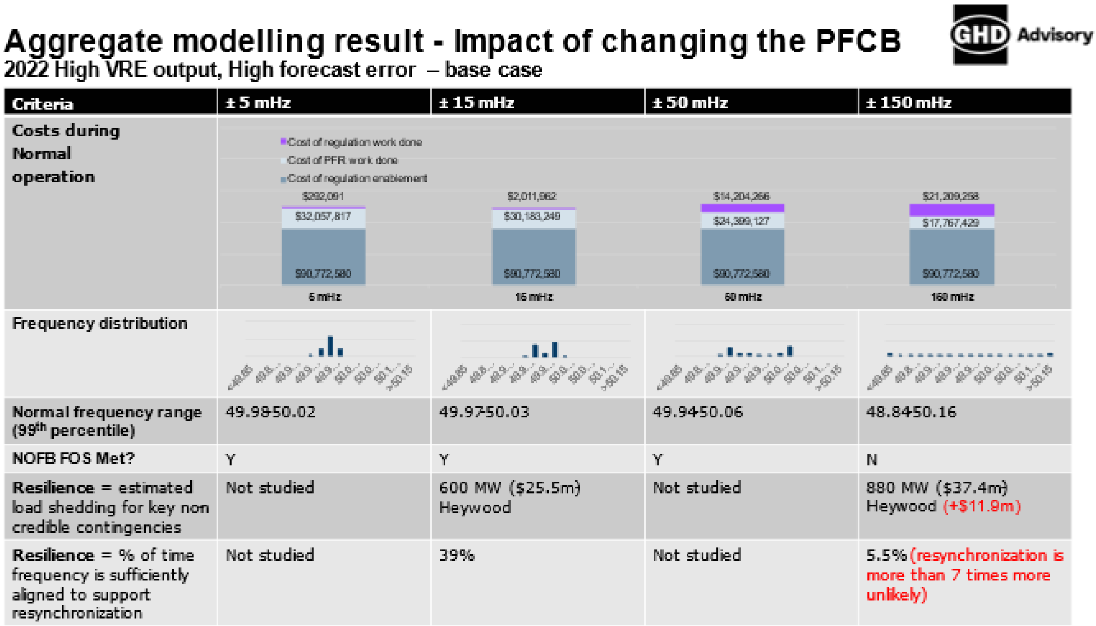
A narrow setting for the PFCB delivers lower total costs for controlling system frequency

The GHD analysis also predicts that narrower settings for the PFCB would deliver lower total costs for control of power system frequency. The expected reduction in costs for narrower PFCB settings accounts for the costs of both PFR and regulation FCAS which work together to control frequency during normal operation.

The GHD analysis predicts that wider settings for the PFCB would result in degradation of frequency performance, consistent with operational experience in the NEM during the period 2015 – 2020. Wider PFCB settings were also expected to result in lower costs for work done by generators through automatic PFR. However, costs associated with work done by regulation services were shown to increase for wider PFCB settings, more than offsetting any reduction in costs for PFR.

The high-level results from the GHD analysis are shown below in Figure 1.1.

Figure 1.1: Summary of results for GHD PFCB analysis - High VRE, High Forecast error



Aggregate modelling result - Impact of changing the PFCB

2022 High VRE output, High forecast error – base case

Criteria	± 5 mHz	± 15 mHz	± 50 mHz	± 150 mHz
Costs during Normal operation (Cost of regulation work done; Cost of PFR work done; Cost of regulation enablement)	5 mHz: $292,091; $32,057,817; $90,772,580	15 mHz: $2,011,962; $30,183,249; $90,772,580	50 mHz: $14,204,266; $24,399,127; $90,772,580	150 mHz: $21,209,258; $17,767,429; $90,772,580
Frequency distribution				
Normal frequency range (99th percentile)	49.9850.02	49.9750.03	49.9450.06	48.8450.16
NOFB FOS Met?	Y	Y	Y	N
Resilience = estimated load shedding for key non credible contingencies	Not studied	600 MW ($25.5m) Heywood	Not studied	880 MW ($37.4m) Heywood (+$11.9m)
Resilience = % of time frequency is sufficiently aligned to support resynchronization	Not studied	39%	Not studied	5.5% (resynchronization is more than 7 times more unlikely)

Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.iii.

The settings for normal operation should be reviewed again by no later than the end of 2027

The Panel recognises that it is necessary for narrow band PFR to control frequency close to 50 Hz. Under the current arrangements, there is a reliance on mandatory PFR to deliver this narrow band control. The frequency performance payments arrangements, which commence from 8 June 2025, are expected to provide an incentive for the provision of narrow band PFR beyond and in addition to the mandatory requirement. The Panel recognises that it would be appropriate to review the settings in the FOS for normal operation, including the PFCB, again at a future date. This future review would be able to account for the rapid rate of change in the power system and also to review the economic and operational outcomes following the commencement of the new frequency performance payments arrangements.

The Panel recommends that a subsequent review of the FOS be completed by no later than the end of 2027, which will allow for a period of 12 - 18 months to monitor the impacts of the frequency performance payments arrangements and inform further consideration of the PFCB and the settings in the FOS for normal operation. Further commentary on this follow-up review for the FOS is included in section 1.3.3.

1.1.5 The removal of the limit on accumulated time error

Consistent with the draft FOS, the revised FOS removes the quantitative limit on accumulated time error while retaining a requirement for monitoring and reporting obligations. This is achieved by maintaining time error as a component of the FOS, while clarifying that there is no effective limit that must be met. Therefore, we expect that AEMO will continue to monitor and report on time error on a weekly and quarterly basis, consistent with clause 4.8.16 of the NER.

Time error is a measure of the accumulated time the power system has spent away from the nominal frequency target of 50 Hz. Advice from AEMO and GHD indicate that time error accumulation has minimal impact on market participants and consumers. At the same time, the existing requirement in the FOS for time error not to exceed 15 seconds drives additional procurement of regulation FCAS and the practise of time error correction which result in increased costs for operating the power system. AEMO estimates that the cost of procuring additional regulation services to respond to time error is in the order of $1.9M to $2.8M per year.

By continuing to monitor and report on time error, AEMO will continue to provide value and transparency to stakeholders as a measure of system frequency performance, while the FOS will no longer set any hard limits on the allowable range for accumulated time error. This change will provide AEMO with more flexibility in relation to how it manages time error and will allow system changes over time to support reductions in associated costs due to time error correction.

Further detail on this element of the revised FOS is included in chapter 7.

1.2 The Panel has taken into account stakeholder feedback

In making this final determination, the Panel has taken account of stakeholder feedback through formal submissions to an issues paper published on 28 April 2022 and a draft determination published on 8 December 2022. We received eleven submissions in response to the issues paper and nine submissions in response to the draft determination from interested stakeholders representing industry bodies, TNSPs/DSNPs, and generators. Stakeholders expressed general support for the review and the issues identified by the Panel for consideration.

The following sections describe how the Panel's determination and revised FOS have been informed by stakeholder input, with respect to:

- the introduction of a limit on system RoCoF following contingency events
- changes to the limits and thresholds for contingency events
- changes to the FOS to clarify the expectations during system restoration
- the target and allowable range for frequency during normal operation and the associated setting for the PFCB that relates to the sensitivity of PFR provided by scheduled and semi-scheduled generators
- the removal of the limit for accumulated time error.

1.2.1 Stakeholders expressed general support for including RoCoF limits in the FOS — subject to further detailed analysis and a forward plan to support ongoing reform

The revised FOS includes limits on the maximum allowable RoCoF following contingency events, supported by technical advice provided by AEMO and a survey of international approaches to managing RoCoF undertaken by GHD. This approach to the development of RoCoF limits is consistent with stakeholder views that indicated support for the inclusion of standards for RoCoF following contingency events to specify the safe operating range for the power system and support the development of future arrangements to meet the system requirement for RoCoF control services.

The RoCoF limit in the revised FOS for the mainland NEM has been informed by AEMO's assessment of the safe operating range for RoCoF based on the RoCoF withstand capability for the existing generation fleet and the capabilities of emergency frequency control schemes. This is consistent with the views expressed by the AEC and CS Energy that, in setting a limit for system RoCoF, the Panel should take into account the capability of existing generators and the performance of UFLS.[9]

The Panel acknowledges concerns expressed by the CEC, that the prescription of system RoCoF limits may lock in a requirement to meet this limit through the provision of inertia by incumbent synchronous generators, which may themselves drive the need for a low RoCoF limit through their individual RoCoF withstand capability.[10] The Panel considers that the RoCoF limits in the revised FOS are an initial step and will inform further regulatory reforms with the goal of developing market and regulatory arrangements for the efficient provision of inertia and RoCoF control services, such as the AEMC's consideration of reforms to inertia, as discussed in section 1.3.2. The Panel expects that the initial RoCoF limits set out in the revised FOS could be increased in the future subject to confirmation of increased RoCoF withstand capability of the generation fleet. The Panel will monitor related power system developments and report its findings through its Annual market performance review process and recommends a follow-up review of the FOS be completed by no later than the end of 2027. This will allow the Panel to reassess the RoCoF limits in the FOS in light of changes in the power system.

Further detail on this element of the revised FOS is set out in chapter 3.

9 Submissions to the issues paper: AEC, p.4; Ergon Energy & Energex, p.1.
10 CEC, submission to the draft determination, pp.2-3.

1.2.2 The limits and thresholds for contingency events have been revised in response to stakeholder feedback

The settings in the revised FOS that relate to the contingency containment bands, contingency thresholds, and contingency limits have been determined with consideration for stakeholder views, as set out below.

Stakeholders expressed support for maintaining the existing contingency containment bands in the FOS

Supported by AEMO's advice, the Panel has determined to maintain the current allowable ranges for frequency following contingency events, including the existing containment, stabilisation bands and recovery bands, and associated timings. This determination aligns with stakeholder views, that note the existing contingency containment settings appear to be fit for purpose.[11]

Stakeholders expressed a range of views on the limit for the maximum allowable credible contingency event in Tasmania

Stakeholder responses to the draft determination were generally supportive of confirming the existing 144MW limit for generation events in Tasmania and extending this limit to apply to load and network events.

The Panel notes that Woolnorth Renewables, the owner of the affected Musselroe Wind Farm, supported an increase in the limit to 155MW.[12] On the other hand, TasNetworks supported the continuation of the 144MW limit and recommended the Panel extend it to include network and load events due to the small size of the Tasmanian grid and the limited availability of fast FCAS in the region.[13]

The Panel considered whether it would be viable to increase the limit on the size of the largest credible contingency event in Tasmania, as proposed by Woolnorth Renewables, and notes the reasoning provided in its submission to the issues paper. Raising the current limit from 144MW to 155MW would allow for the Musselroe Wind Farm to operate unconstrained at all times, as was the case during the period July 2013 to January 2020.[14] The Panel understands that a new generator contingency scheme commenced operation in Tasmania in December 2021, allowing Musselroe Wind Farm to operate without constraint when sufficient load tripping services are available.[15]

Stakeholders urged caution in relation to the potential application of a limit on maximum allowable contingency events for the mainland

In line with the AEMO advice, the Panel has determined not to apply a limit on credible contingency size in the mainland. This outcome was supported by stakeholder submissions to the issues paper and draft determination, who raised concerns with the inflexibility of

11 Submissions to the issues paper, AEC, p.4.; Ergon Energy & Energex, pp.2-3.; TasNetworks, pp.1-2,5.
12 Woolnorth Renewables, submission to the issues paper, pp.1-2.
13 TasNetworks, submission to the issues paper, pp.5-6; TasNetworks submission to the draft determination, p.2.
14 Woolnorth Renewables, submission to the issues paper, p.5.
15 TasNetworks, submission to the issues paper, p.5.

including such a limit in the FOS and concerns that it may dissuade investment in larger generation plants.[16] The AEC did recognise that such a limit could deliver improved transparency for new connections when compared to the existing connection process.[17] The AEC noted that an alternative approach would be for the Panel to recommend the publication of a list of maximum acceptable contingency sizes in different locations of the NEM.

A summary of the Panel's consideration of these issues is provided in chapter 4.

1.2.3 The drafting of the FOS for system restoration has been revised for improved clarity and consistency

The Panel's assessment of the FOS that applies during supply scarcity was triggered by concerns raised by stakeholders that queried the appropriateness of the current settings in the FOS that apply for the purpose of system restoration at times of supply scarcity.[18] Stakeholders supported the revisions proposed in the draft FOS to provide a clearer description of how and when this element of the FOS applies. It was also suggested that the FOS drafting could more directly refer to the restoration of load which is a key attribute of this element of the FOS.[19]

The Panel acknowledges stakeholder suggestions for the phrase "load restoration". However, in alignment with advice from AEMO, the Panel has determined that the phrase "system restoration" better describes the objective for this element of the FOS and reduces the likelihood that operations staff will misinterpret the conditions under which this element of the FOS applies. The revised FOS includes changes to refer to this element as the expected frequency outcomes during "system restoration".

In response to AEMO's feedback on the draft determination, the Panel has also determined that the operational frequency tolerance band (OFTB) during system restoration be revised from 48 – 52 Hz to 49 – 51 Hz. This change will align the expected frequency withstand capability for connecting generators with the expected worst-case system frequency performance set out in the FOS.[20]

Further detail on the Panel's consideration for this element of the revised FOS is provided in chapter 5.

1.2.4 The Panel's determination for the settings in the FOS for normal operation responds to stakeholder views

The Panel is aware of a wide range of stakeholder views in relation to the settings in the FOS that apply during normal operation and the interaction of these with the PFCB that relates to the sensitivity for mandatory PFR provided by scheduled and semi-scheduled generators. Stakeholders generally accept that frequency performance in the NEM has improved significantly following the introduction of mandatory narrow band PFR and the initial narrow

16 Submissions to the issues paper: AEC, p.4; Delta Electricity, p.15; Origin Energy, p.2; Iberdrola, p.6; Submissions to the draft determination: AEC, p.4; CS Energy, p.6.; Origin, p.1; Shell Energy, p.3.

17 AEC, submission to the issues paper, pp.4-5.

18 Shell Energy, submission to the issues paper, p.4.

19 Submissions to the draft determination: CS Energy, p.7; Delta Electricity, p.1; Shell Energy, p.2.

20 AEMO, submission to the draft determination, p.2.

setting in the NER for the PFCB of 49.985 – 50.015 Hz.[21] However, stakeholders expressed a strong desire that the Panel's consideration of the PFCB and NOFB be supported by independent economic analysis to investigate the benefits of tight frequency control with the costs of achieving this outcome.[22]

The Panel's determination of the NOFB and PFCB was informed by quantitative analysis of the associated costs and benefits

Consistent with stakeholder expectations, the Panel's determination for this element of the FOS was informed by quantitative analysis of the costs and benefits of varying the setting for the PFCB. This analysis, undertaken by GHD, has considered the implications for system security and resilience as well as the ongoing operational costs associated with enablement and provision of regulation services and the costs of providing PFR by responsive plants. The GHD analysis showed that having more generation plants be responsive closer to 50 Hz drove a tighter frequency distribution and lead to overall reduced operating costs for the system along with improved system resilience to contingency events. In response to the draft determination, many stakeholders acknowledged the value of the GHD analysis in providing a better understanding of the cost-benefit trade-off associated with the settings in the FOS for normal operation.[23]

Some generator representatives consider that the Panel's analysis should have been extended to consider a slight widening of the PFCB to ±30 mHz, noting the advice provided by Provecta for the AEC that such settings may support the smoother operation of certain synchronous thermal generation.[24] The Panel notes the GHD analysis included consideration of various deadband settings within the range ±5 mHz to ±500 mHz and considers that the results of those studies were sufficient to inform its determination.[25]

The Panel recommends that a subsequent review of the settings in the FOS for normal operation be completed by no later than the end of 2027.

Submissions from AEMO, the CEC, and TasNetworks supported the Panel's draft FOS for normal operation and agreed that it would be appropriate to revisit these settings by no later than 2027 following the commencement of the new frequency performance payments regime in the NEM in 2025.[26] On the other hand, a number of stakeholders consider that the Panel should undertake a follow-up review of these settings sooner: Shell Energy proposes a review 12 months after the commencement of the revised FOS and Delta Electricity proposes a review after the PFR incentive arrangements commence in June 2025, but prior to the first half of 2027. [27] The Panel's recommendation is that a subsequent review of the settings in the FOS for normal operation be completed by, no later than the end of 2027. This allows for a

21 For example, submissions to the issues paper: AEC, p.1; EnergyAustralia, p.1-2; TasNetworks, p.3.

22 For example, submissions to the issues paper: AEC, pp.2-3; Delta Electricity, p.2; EnergyAustralia pp.2-3; SnowyHydro, p.1; CSEnergy, pp.2-7, Shell Energy, p.3; Iberdrola, pp.2-3; Origin Energy, pp.1-2.

23 For example, submissions to the draft determination: AEMO, p.1; CEC, p.1l SnowyHydro, p.1; TasNetworks, p.1.

24 For example, submissions to the draft determination; AEC, p.2; Origin Energy, p.1; Shell Energy, p.4.

25 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the Primary Frequency Control Band in the NEM, 21 November 2022, p.10.

26 For example, submissions to the draft determination: AEMO, p.1; CEC, p.1; TasNetwork, p.1.

27 Submissions to the draft determination: Delta Electricity, p.4.; Shell Energy, p.5.

period of 12 – 18 months to monitor market and system outcomes with the new frequency performance payments arrangements in effect. The outcomes of this monitoring will inform the Panel's review of the the settings in the FOS for normal operation.

The Panel acknowledges the proposal that the FOS more closely specify the required frequency outcomes during normal operation

The Panel also notes concerns expressed by generator representatives and the AEC with the process for the review of this element of the standard and a desire for the Panel to refocus its attention on revising the FOS to better reflect the expected frequency performance during normal operation.[28] The Panel notes that the results from the GHD analysis support the consideration of a narrowing of the NOFB, or the inclusion of additional bands within the NOFB to reflect the expectation that frequency be held more closely to 50 Hz (such options were outlined for consideration in the issues paper).

The Panel notes AEMO's advice that the narrowing of the NOFB, or the inclusion of additional bands within the NOFB, is not an immediate priority and may present unknown risks.[29] Further, in the absence of the implementation of the frequency performance payments arrangements, AEMO would not have any available tools with which to effectively modulate the level of aggregate frequency responsiveness (aggregate PFR) in the system to meet a narrower frequency distribution standard. The Panel expects that the ongoing monitoring and reporting of aggregate frequency responsiveness combined with the commencement of new frequency performance payments arrangements will provide the basis for the specification of the expected frequency range to be reconsidered through a subsequent review of the FOS. The Panel recommends that this subsequent review be completed by no later than the end of 2027.

Further detail on the Panel's consideration for this element of the revised FOS is provided in chapter 6.

1.2.5 Stakeholders expressed support for the removal of the limit on accumulated time error

The revised FOS abolishes the requirement for AEMO to correct for time error accumulation, but maintains the existing monitoring and reporting obligations. This outcome aligns with stakeholder views, corroborated by AEMO and GHD's survey, that correcting for time error accumulation does not materially improve power system security.[30] Moreover, in response to stakeholder feedback, the Panel has maintained the existing transparency obligations to enable the tracking and monitoring of time error accumulation as stakeholders consider it to be a valuable frequency performance metric.

Stakeholder responses to the draft determination were broadly supportive of this change.[31]

Further detail on the Panel's consideration for this element of the revised FOS is provided in chapter 7.

28 For example, submissions to the draft determination: AEC, p.2; CS Energy, pp.2-3.

29 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.22.

30 Submissions to the issues paper: AEC, p.5; TasNetworks, pp.6-7; EnergyAustralia, p.4; Iberdrola, p.6.

31 Submissions to the draft determination: AEC, p.4; CEC, p.1; CS Energy, p.7; Delta Energy, p.1.

1.3 The revised FOS paves the way for the future power system

This determination is part of an ongoing program of reforms to adapt the market and regulatory arrangements to meet the needs of the future power system. There are a number of ongoing and upcoming reform processes that directly relate or overlap to some degree with the changes made by the final rule. Two particularly relevant projects include:

- the commencement of procurement arrangements for very fast FCAS from 9 October 2023 — discussed further in section 1.3.1.
- the AEMC's consideration of the *Efficient provision of inertia* rule change request — discussed further in section 1.3.2.

The Panel will continue to monitor system frequency performance through its *Annual market performance review* and recommends that a subsequent review of the FOS be completed by no later than the end of 2027. The next review would enable the settings in the FOS to be reconsidered in light of the ongoing operational and regulatory changes in the power system. This recommendation is described further in section 1.3.3.

1.3.1 The revised FOS will support the roll-out of very fast FCAS

The establishment of RoCoF limits in the FOS will help AEMO establish systems for the specification and enablement of new "very-fast" contingency FCAS products which are set to commence on 9 October 2023. AEMO published a final determination for an updated market ancillary service specification on 7 October 2022, including new specifications for the very-fast raise and very-fast lower products.[32]

The new "very-fast" contingency products will have a 1-second response time and a 6-second delivery time, before handing over to the existing "fast" services that have a 6-second response time. While these services are not envisaged to be used to control RoCoF, it is envisaged that the definition of a RoCoF limit for credible contingency events will enable a pre-contingent volume of inertia to be determined that will help to determine the required volume of very fast FCAS to respond following a contingency event.

The revised FOS will take effect at the same time as the new market ancillary service arrangements for the very fast contingency FCAS on 9 October 2023.

1.3.2 The revised FOS is part of an ongoing work program for the efficient provision of inertia/RoCoF control services

On 15 December 2021, the AEMC received a rule change request for *Efficient provision of inertia* from the Australian Energy Council (AEC).[33] On 2 March 2023, the AEMC initiated the rule change process and published a consultation paper for this rule change request.[34]

The Panel notes that the RoCoF limits included in the revised FOS provide an important input into the Commission's assessment of the AEC's rule change request. These RoCoF limits set the expected operational outcome for system RoCoF following contingency events. As set out

32 Refer to: https://aemo.com.au/consultations/current-and-closed-consultations/amendment-of-the-mass-very-fast-fcas

33 Refer to: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia

34 AEMC, Efficient provision of inertia — Consultation paper, Consultation paper, 2 March 2023

in the issues paper, the Panel notes that the initial post-contingent RoCoF is a function of contingency size and the level of inertia present on the power system.[35] Therefore, defining a RoCoF limit helps to better define the required frequency outcomes and therefore support ongoing efforts by AEMO to "research the application and benefits of physical and synthetic inertia" in the power system.[36]

The Panel considers that the post-contingency RoCoF limits set in the FOS are an initial setting, based on a conservative assessment of the current RoCoF withstand capability of the generation fleet. AEMO's assessment is that some incumbent synchronous generators may not tolerate system RoCoF within the range of 1Hz/s up to 2Hz/s.[37] At the same time, connecting generators must demonstrate the minimum capability to withstand RoCoF of up to 2Hz/s for up to 250 milliseconds and 1Hz/s for up to 1 second and the expected (automatic) standard is for connecting generators to demonstrate the capability to withstand RoCoF up to 4Hz/s for up to 250 milliseconds and 3Hz/s for up to 1 second.[38] There is an expectation that the RoCoF withstand capability in the generation fleet should increase over time and this would support the Panel's consideration of a wider setting for the system RoCoF limits in the FOS at a future date. The Panel notes that a broadening of the system RoCoF limit would likely deliver net-benefits to consumers, subject to this being aligned with the withstand capability of the generation fleet.

The Panel recommends further work by AEMO and the AEMC to support the progressive broadening of the RoCoF withstand capability of the generation fleet, subject to consideration of the associated costs and benefits. The Panel understands that there are immediate opportunities to progress this objective through the:

- *AEMO review of the technical requirements for connection* — commenced in October 2022[39]
- AEMC's assessment of the *Efficient provision of inertia* rule change request.[40]

1.3.3 The Panel will continue to monitor system frequency performance and recommends a follow-up review of the FOS by no later than 2027

The Panel will continue to monitor frequency performance and related developments through its *Annual market performance review*. In particular, the Panel intends to monitor and report on:

- frequency performance with respect to the new system limit on RoCoF following contingency events
- regulatory and procedural developments that relate to RoCoF, including the outcomes from the *AEMO review of the technical requirements for connection* with respect to

35 Refer to section 5.1 of the issues paper for further detail.

36 AEMO, AEMO advice: reliability Panel review of the frequency operating standard, 8 December 2022, p.42.

37 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.24.

38 NER clause S5.2.5.3.

39 Refer to: https://aemo.com.au/consultations/current-and-closed-consultations/aemo-review-of-technical-requirements-for-connection

40 Refer to: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia

RoCoF and any related future rule changes, and developments through the *Efficient provision of inertia* rule change

- frequency performance during normal operation and the interaction with aggregate frequency responsiveness.

The Panel recommends that a follow-up review of the FOS be completed by no later than the end of 2027. This timing would allow for further consideration of:

- The settings in the FOS for normal operation, including the NOFB, NOFEB, and PFCB in the context of the new frequency performance payments arrangements that commence on 8 June 2025. The proposed timing for a follow-up review allows for 12 - 18 months to monitor the impact of the frequency performance payments on frequency performance in the NEM, including the degree to which the incentive arrangements deliver increased voluntary PFR.
- RoCoF limits in the context of power system and market developments. In addition to the interaction between the FOS review and the *Efficient provision of inertia* rule change, the Panel notes that it would be appropriate for a follow-up review of the FOS to consider the system RoCoF limits in the context of the predicted rapid change to the generation fleet over the coming years. This subsequent review would consider whether the technical capabilities of power system plant support adjustment of the RoCoF limits included in the revised FOS.
- The settings in the FOS for Tasmania, including the limit on the largest allowable credible contingency event in Tasmania in the context of power system and market developments. The future developments that have the potential to shift the operating envelope in Tasmania include:
    - commencement of market ancillary service arrangements for very fast contingency services from 9 October 2023
    - detailed system planning to integrate Marinus Link into the Tasmania system. The 2022 ISP identifies the Marinus Link as an actionable ISP project to provide a second DC inter-connector between Tasmania and the mainland NEM. Stage 1 is scheduled for commissioning in mid-2029, followed by stage 2 in mid 2031.[41]

41 AEMO, 2022 Integrated system plan, 30 June 2022, p.13.

2 THE REVISED FOS WILL CONTRIBUTE TO THE NATIONAL ELECTRICITY OBJECTIVE

BOX 1: KEY POINTS IN THIS SECTION

- The Panel determined that the revised FOS is in the long-term interests of consumers. The Panel's determination aims to contribute to meeting the National Electricity Objective (NEO) by managing the trade-off between the benefits of a secure and resilient power system and the associated costs of achieving this.
- The Panel considers that the additions and amendments to the FOS are crucial to help maintain system security in the context of a rapidly transitioning electricity network. This aligns with stakeholder submissions that emphasised the need to closely re-examine the settings in the FOS in light of increasing operational risks throughout the system.
- The Panel's determination is based on the assessment principles outlined in the issues paper.

This section explains why the Panel has made its final determination and the accompanying revised FOS. This section includes:

- Section 2.1 — the revised FOS is in line with the energy objective
- Section 2.2 — considering the changes in the FOS against the assessment criteria
- Section 2.3 — the revised FOS is in the best long-term interests of consumers.

2.1 The revised FOS is in line with the national electricity objective

In accordance with the terms of reference for the review, the Panel's final determination is guided by the National Electricity Objective (NEO).[42] The NEO is set out in the National Electricity Law (NEL) as being:[43]

BOX 2: THE NEO

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 -

- price, quality, safety, reliability, and security of supply of electricity; and
- the reliability, safety and security of the national electricity system."

The Panel is satisfied that the additions and amendments to the FOS will be likely to contribute to the achievement of the NEO. The changes will help support the security of the

42 Section 88 of the NEL.
43 Section 7 of the NEL.

transitioning power system and deliver reduced costs for frequency control over the long term by providing AEMO with the crucial operational tools.

For further information on the Panel's decision-making process please refer to:

- Appendix A — consultation and development process
- Appendix B — background and context.

2.2 Considering the changes in the FOS against the assessment principles

In reviewing the FOS, the Panel considered how changes are likely to promote the NEO. The Panel identified the following assessment criteria to support that objective:

- promoting power system security
- appropriate risk allocation
- efficient investment in, and operation of, energy resources to promote secure supply
- technology neutral
- flexibility
- transparent, predictable, and simple
- consumer preferences.

A detailed explanation of these assessment criteria can be found in Section 2.2 of the draft determination. The rest of this section explains how the revised FOS will promote the long-term interests of consumers with respect to these principles.

2.3 The revised FOS is in the long-term interests of consumers

This section outlines how the revised FOS supports the long-term interests of consumers with respect to the assessment principles described in section 2.2.

2.3.1 The settings in the FOS promote power system security

The revised FOS will **promote power system security** by introducing a RoCoF standard, extending the generator event size limit in Tasmania to cover network and load events, and maintaining the current settings for normal operation.

The RoCoF standards will contribute to the satisfactory operation of UFLS and reduce the likelihood of cascading generator outages

The Panel's introduction of a post-contingency RoCoF standard will increase the likelihood of plants having sufficient ride-through capability to continue generating and the likelihood of under frequency load shedding (UFLS) schemes operating as intended. This assists in preventing situations where a significant contingency event could lead to cascading generator outages or compromising the satisfactory operation of UFLS, leading to a black system event.

The 144MW contingency event limit in Tasmania helps maintain the network within its secure operating envelope

The Panel's determination extends the 144MW generator event limit to include network and load events in Tasmania, thereby contributing to system security by maintaining the network within its technical operating envelope. The limit will provide guidance to connecting loads, such as hydrogen electrolysers or data centres, of the safe hosting capacity of the network and ensure that the connection arrangements take into consideration the risks to system security.

The Panel's final determination confirms that the settings for normal operation and the PFCB maintain frequency control

The Panel concluded that there currently is no alternative to narrow band PFR that provides the same level of frequency control. More effective frequency control is also shown to improve the system's resilience to significant contingency events, that could otherwise result in extensive load shedding. However, given the upcoming implementation of the *PFR incentive arrangements* rule, the Panel considers that it would be appropriate to re-examine the settings once the frequency performance payments mechanism is sufficiently established.

2.3.2 The FOS ensures risks are placed on those best able to manage them

The allocation of risk and accountability for investment and operational decisions should rest with the parties best placed to manage them.

AEMO is best placed to manage the operational risks arising from rising RoCoF

The introduction of system standards for post-contingency RoCoF will require AEMO to maintain frequency within the limits set out in the FOS. This will promote system resilience and alleviate the risk of unreliable electricity supply for consumers. The Panel considered that AEMO is best placed to manage RoCoF due to its system security responsibilities, its overview of the power system, and its role in the procurement of ancillary services.

TNSPs and AEMO cooperate together to manage contingency risks on the mainland

The Panel decided not to introduce a maximum contingency size limit for the mainland, as TNSPs and AEMO are better placed to manage contingency risks through the connections process. Frequency is not always the limiting factor when considering connection applications, and TNSPs are more capable of taking into account the overall stability and safe hosting capacity of the network. Moreover, TNSPs will be more reactive to network upgrades which may increase the safe hosting capacity in a particular region.

2.3.3 The FOS promotes efficient investment in, and operation of, energy resources to manage the trade-off between security and economic efficiency

AEMO, generators, NSPs, and other market participants all contribute to the maintenance of system security. The Panel appropriately balanced the trade-off between economic costs and system security benefits to promote **efficient investment in**, and **operation of**, the power system.

The standards for RoCoF guide the efficient procurement of ancillary services

By setting a standard for post-contingency RoCoF, the Panel has provided AEMO with guidance on the economically efficient quantity of FFR or other ancillary services that should be procured to maintain system security. The revised FOS introduces a wider standard for Tasmania compared to the mainland due to the greater RoCoF withstand capabilities of hydroelectric generators. The Panel recognises that the settings in the FOS should be periodically updated to reflect the changing capabilities or mix of generators.

The Panel considered the trade-off between costs and benefits in setting the limits for RoCoF. If the limit were set above the technical capability of elements of the generation fleet, the risk of generator disconnection following system disturbances would remain and there would be limited system security benefits. Conversely, if the limit were set too low, then the market would be over-constrained, resulting in excessive costs due to constraints on energy dispatch and the procurement of ancillary services. The Panel determined that the RoCoF settings in the FOS will appropriately balance system security and economic efficiency, thereby promoting efficient investment in, and operation of, the power system.

The FOS extends the Tasmanian contingency size limit to include network and load events due to scarce availability of FCAS

The Panel's determination to extend the generator event limit in Tasmania to include network and load events manages the trade-off between greater economies of scale and the costs of ancillary services. AEMO advice confirmed the Panel's assessment that a higher limit would not be in the economic interests of consumers due to the severely constrained availability and costs of fast FCAS in Tasmania.

Introducing a contingency size limit for the mainland would lead to inefficient operation and investment decisions

The Panel recognised that a contingency size limit in the mainland would have a detrimental effect on an efficient allocation of investment. The potential system security benefits are not sufficient to compensate for the expected decrease in economic efficiencies. The Panel considered that the Commission may want to investigate a more explicit co-optimisation of marginal contingency FCAS costs and increasing contingency sizes to result in an optimal equilibrium.

The FOS retains the current settings for normal operation to maintain system security at lowest aggregate costs for consumers

The Panel's decision to maintain the current settings for normal operation is determined by the need for system security to be maintained in a cost effective way. Advice from AEMO and modelling from GHD showed that retaining the current settings would result in lower aggregate frequency control costs when compared to wider deadbands.

Removing the requirements to correct for time error should result in reduced costs to consumers

The revised FOS removes the requirement for AEMO to correct for the accumulation of time error. The Panel determined that the costs, ultimately borne by consumers, were not justifiable given the lack of any security or consumer benefits.

2.3.4 The settings in the FOS are technologically neutral

The assessment criteria state that regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should **not be targeted or designed with a particular technology** in mind.

The Panel's determination and the revised FOS do not distinguish or differentiate between the treatment of different technologies. The standards are consistent for all participants and put security benefits and economic efficiencies at the centre of decision-making, rather than supporting particular technologies.

2.3.5 The settings in the FOS are flexible in changing market and external conditions, especially the decarbonisation of the power system

Regulatory arrangements must be **flexible to changing market and external conditions**. They must remain effective in achieving security outcomes over the long-term in a changing market environment. As such, the Panel's determination aligns with the generation mix and operational conditions of both Tasmania and the mainland.

The RoCoF standard following contingency events differentiates between the mainland and Tasmania to account for the greater RoCoF withstand capabilities of hydroelectric generators. The Panel considered that the settings are flexible and should be periodically updated to reflect changes in generator mix and UFLS performance in order to re-optimise the trade-off between security and economic efficiency.

Despite confirming the settings for normal operation, the Panel remains flexible to re-examining the settings following the implementation of the *PFR incentive arrangements rule*. It is expected that the introduction of the frequency performance payments arrangements will have a material impact on the cost-benefit analysis. The Panel's intent of reviewing the FOS by no later than the end of 2027, will also help to make sure the arrangements are flexible and can adapt to change.

2.3.6 Settings in the FOS are transparent, predictable, and simple

The revised FOS is transparent, predictable, and simple so that market participants can make informed and efficient investment and operational decisions.

The 144MW contingency size limit in Tasmania provides clear guidance for connecting parties

The FOS extends the 144MW generator event limit in Tasmania to apply to network and load events. The extension of the limit will provide connecting parties, such as data centres and hydrogen electrolysers, with transparency to design their plant accordingly.

Guidelines developed by AEMO and TNSPs should improve transparency on the hosting capacity of the mainland

The Panel sees merit in AEMO and TNSPs developing clear guidelines to provide transparency on the hosting capacity on the mainland grid. Such guidelines would clarify the hosting capacity of the network and would set clear expectations for market participants on design attributes that need to be taken into consideration.

Retaining reporting obligations on accumulated time error maintains transparency for market participants

In response to stakeholder feedback, the Panel determined that the FOS will retain an obligation on AEMO to report and monitor on time error accumulation as a frequency performance metric. Consequentially, stakeholders can expect the same level of transparency they have been accustomed to.

Simplifications made to system restoration improve transparency and predictability in the FOS

The Panel's decision to rename "supply scarcity" as "system restoration" improves simplicity and transparency around the intention of the settings, which have been misinterpreted in the past. Further, the revised OFTB for system restoration conditions improve simplicity and predictability by aligning with the OFTB bands during normal and island conditions in the mainland.

2.3.7 Settings in the FOS reflect and enable consumer preferences and benefits respectively

Regulatory arrangements should take into account **consumer preferences**. As such, the Panel considered the costs and benefits to consumers, and the impacts on the consumer experience and delivery of power system services.

The settings in the FOS specify the safe and secure range for operation of the power system. This aligns with the consumer preference for the system to be operated in a safe and secure manner, while minimising the associated costs due to constraints on dispatch and procurement of ancillary services. This is demonstrated through:

- the settings for RoCoF limits following credible and non-credible contingency events, which are respectively based on the technical capability of the existing generation fleet and emergency frequency control schemes
- the extension of the limit on the maximum credible contingency size in Tasmania, which is based on the technical hosting capacity of the Tasmanian power system
- the determination to not include a limit on the maximum allowable contingency limit in the mainland, which would be unnecessarily restrictive given the alternative options for managing the associated risks of large connection application in the mainland
- the confirmation of the narrow setting for the PFCB to support the tight control of frequency around 50 Hz — this will deliver benefits to consumers through increased system resilience, while also reducing the overall costs of frequency control when compared to wider settings of the PFCB under the current regulatory framework
- the removal of the requirement for AEMO to correct for accumulated time error, which would allow for changes to AEMO's operational practices to optimise the procurement and use of regulation services.

3 THE REVISED FOS INTRODUCES LIMITS FOR RATE OF CHANGE OF FREQUENCY

BOX 3: KEY POINTS IN THIS SECTION

Requirements for the rate of change of frequency (RoCoF) following contingency events

- The Panel has revised the FOS to include limits for RoCoF following contingency events. These limits would reflect changing operational conditions with the expected retirement of synchronous generation and associated reduction in inertia, which acts to restrain RoCoF following contingency events.
- These new elements of the FOS will contribute to power system security by requiring AEMO to operate the system within the capabilities of existing generation plant and emergency frequency control schemes (EFCS/UFLS).
- They would also promote the efficient investment in, and operation of, energy resources by supporting the valuation and procurement of essential system services to manage post-contingency RoCoF such as:
  - the implementation of market ancillary service arrangements for fast frequency response services, which commence on 9 October 2023
  - the potential development of complementary arrangements to procure RoCoF control services from synchronous and synthetic inertia.
- The RoCoF requirements for Tasmania differ from the mainland due to the specific operational characteristics in the Tasmanian system. This reflects the higher RoCoF ride-through capabilities of the local generation fleet and the settings implemented by TasNetworks for existing dynamic control schemes used to manage non-credible contingency events.
- The inclusion of RoCoF limits in the FOS provides transparency on this important system metric and will help support secure and efficient operational outcomes into the future.
- The Panel will monitor developments with respect to RoCoF through its annual market performance review, with a view towards potentially increasing the system RoCoF limits in the future.
- The Panel emphasises that connecting generation plant must be capable of meeting the RoCoF withstand capabilities required under the minimum and automatic access standards set out in clause S5.2.5.3 of the NER. Moreover, the Panel considers that there could be merit is defining RoCoF ride-through standards for network equipment (such as synchronous condensers) to ensure these plant are capable of being operated in a future low inertia system.

The **revised FOS** includes new provisions requiring that:

> Following a *credible contingency event,* the **rate of change of frequency** must not be greater than:
>
> - Mainland: ±1Hz/s (measured over any 500ms period)
> - Tasmania: ±3Hz/s (measured over any 250ms period).
>
> Following a *non-credible contingency* event or **multiple contingency event** that is not a *protected event*, AEMO should use reasonable endeavours to maintain the **rate of change of frequency** within:
>
> - Mainland: ±3Hz/s (measured over any 300ms period)
> - Tasmania: ±3Hz/s (measured over any 300ms period).

The revised FOS includes new requirements for how AEMO manages RoCoF following credible and non-credible contingency events for both the mainland and Tasmania. These new elements of the FOS define the safe operating envelope for the power system in the context of the ongoing reduction in system inertia due to the progressive retirement of synchronous thermal generators.

The results from GHD's survey of international power systems that was undertaken for the Panel shows that despite only the Western Australian South West Interconnected System (SWIS) having implemented a formal operational standard for RoCoF, system operators are increasingly recognising the importance of RoCoF as part of the repertoire of power system security metrics and limits.[44]

The following sections set out how:

- the RoCoF limits would help to define the secure operating envelope for the power system
- the RoCoF limits would support the valuation and provision of RoCoF control services.

The Panel considers that the RoCoF limits in the revised FOS are an initial step and will inform further regulatory reforms with the goal of developing market and regulatory arrangements for the efficient provision of inertia and RoCoF control services, such as the AEMC's consideration of evolving the existing inertia frameworks, as discussed in section 3.2. The Panel acknowledges that the RoCoF limits for the mainland are based on a conservative assessment of the RoCoF ride-through capability of the existing generation fleet. The Panel expects that the initial RoCoF limits in the FOS for the mainland could be increased in the future subject to confirmation of increased RoCoF withstand capability of the generation fleet. As noted in section 1.3, the Panel will continue to monitor frequency performance and

44 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.30.

related developments through its *Annual market performance review* and recommends a follow-up review of the FOS be completed by no later than the end of 2027.

Additional details on the security implications of a reduction in synchronous inertia in the power system and the Panel's considerations when setting limits for post-contingency RoCoF are available in section 3.1 of the [draft determination].

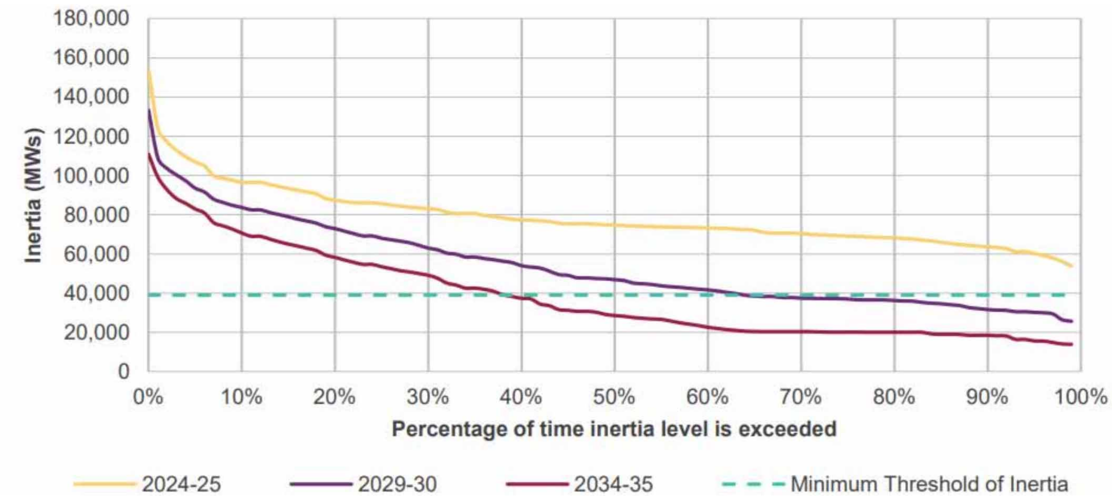
3.1 RoCoF limits would help to define the secure operating envelope for the power system

The limits in the revised FOS for RoCoF following credible and non-credible contingency events specify the range of RoCoF that aligns with secure operation of the power system. This element of the standard is expected to be increasingly important as the power system transitions and levels of synchronous inertia decline which, in the absence of market reforms or operational interventions, is expected to lead to an increase in RoCoF following contingency events.

3.1.1 AEMO projects the progressive decline of power system inertia

As illustrated in Figure 3.1 below, AEMO predicts that inertia in the power system will progressively decrease such that, in the absence of interventions, the 99% availability of inertia will fall below the minimum threshold level for the mainland regions by 2029-30.

Figure 3.1: NEM mainland inertia outlook



Source: AEMO, 2022 Integrated system plan - Appendix 7. Power system security, June 2022, p.33.

As system inertia decreases, there is an expectation that post-contingency RoCoF would proportionally increase which would likely test existing operational practises and plant capabilities. Under current market and regulatory arrangements, AEMO could meet a RoCoF standard in a number of ways, including inertia planning arrangements, limiting contingency size, through the application of constraints on dispatch and the procurement of FFR. In the future additional operational RoCoF control services may become available to AEMO, such as those currently being considered by the Commission through the *Efficient provision of inertia* rule change.

3.1.2 GHD's review of international approaches identifies potential value in specifying system RoCoF limits

The results from GHD's survey of international power systems that was undertaken for the Reliability Panel shows that while only the Western Australian South West Interconnected System (SWIS) has implemented a formal operational standard for RoCoF, system operators are increasingly recognising the importance of RoCoF as part of the repertoire of power system security metrics and limits. Responses to the GHD survey confirmed that:[45]

> Many system operators surveyed consider the need to limit RoCoF to achieve power system security.

3.1.3 The RoCoF limits in the revised FOS reflect the technical capabilities of power system plant

The revised FOS includes limits for RoCoF in the mainland and Tasmania following credible and non-credible contingency events. These settings reflect that:

- the RoCoF requirements following credible events align with the RoCoF ride-through capabilities of generation plant
- the RoCoF requirements for non-credible contingencies relate to the technical capability of emergency frequency control schemes and under frequency load shedding (UFLS).

The consideration of these two factors is described further below.

3.1.4 The RoCoF requirements for credible events align with the RoCoF ride-through capability for generation plant

Generator RoCoF withstand is the capability of generation plant to ride-through different levels of RoCoF following contingency events. Where the RoCoF in the power system exceeds a generator's ride through capability, it may disconnect following a power system disturbance, and have the consequence of making the disturbance worse, potentially leading to a cascading outage and at an extreme, a black system event. The RoCoF limits in the revised FOS align with the expected RoCoF ride-through capabilities of the existing generation mix and is consistent with findings from GHD's survey of international approaches to RoCoF management.[46] The alignment is intended to minimise the risk of generators disconnecting from the grid following a contingency event.

The RoCoF limit set in the revised FOS also aligns with the existing requirements for connecting generators under the automatic and minimum access standards to demonstrate the capability of withstanding a RoCoF of ±4Hz/s and ±2Hz/s respectively, measured over 250ms.[47]

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45 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.30.

46 GHD, Advice for the 2022 Frequency Operating Standard review — System Rate of Change of Frequency, 18 November 2022,pp.30-31

47 Clause S5.2.5.3 of the NER.

AEMO's advice includes an assessment of the RoCoF ride-through capabilities for the current generation fleet in the mainland and Tasmania. The key findings are:

- There remains uncertainty surrounding the withstand capabilities of different types of synchronous plant. AEMO's assessment is that synchronous units can generally be anticipated to ride-through disturbances up to 1Hz/s (with some exceptions), but may demonstrate a range of issues for disturbances around 2Hz/s.[48]
- Inverter-based resources (IBR) typically have higher RoCoF ride-through capabilities. AEMO's assessment is that, as long as protection schemes operate as intended, IBR units are expected to ride through high RoCoF up to 3-4Hz/s.[49]
- The Tasmanian hydroelectric dominated fleet can withstand a higher RoCoF. Hydroelectric generators, despite being synchronous, are capable of withstanding much larger RoCoF when compared with thermal generators. AEMO's advice states that hydro units can be expected to withstand a high RoCoF up to 3Hz/s.[50]

Additional details on the RoCoF ride through capabilities of different types of generators are available in section 3.1.1 of the draft determination.

The RoCoF limits for credible contingencies are tailored to the characteristics of the mainland and Tasmanian systems

The revised FOS RoCoF standards for credible contingencies in both the mainland and Tasmania are tailored to the requirements and particularities of the mainland and Tasmanian generation fleets. The specification of the limits, including the measurement timeframes, are intended to reflect the inherent inertial response of the power system to a significant contingency event. The revised FOS requires AEMO to ensure that:

> Following a *credible contingency event* (which may be a **generation event**, a **load event** or a **network event**), the **rate of change of frequency** must not be greater than:
>
> - Mainland: ±1Hz/s (measured over any 500ms period)
> - Tasmania: ±3Hz/s (measured over any 250ms period).

The codification of standards for post-credible contingency RoCoF was strongly endorsed by stakeholder submissions to the draft determination. Stakeholders recognised the value of the proposed changes in helping maintain system security and setting clear expectations for connected equipment as to what frequency outcomes they are expected to face.[51] The TasNetworks submission to the draft determination supported the introduction of the standard, stating:[52]

48 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.24.

49 Ibid.

50 Ibid.

51 Submissions to the draft determination: CEC, p.1; TasNetworks, p.1; Origin, pp1-2; CS Energy, p.6; Shell Energy, p.1; Delta Electricity, p.1; AEC, p.4.

52 TasNetworks, submission to the draft determination, p.1

> The new requirement to maintain the rate of change of frequency (RoCoF) following credible events and to use best endeavours during non-contingency events is welcomed.

The Panel notes that these RoCoF standards would codify the existing operational arrangements applied by AEMO to manage high RoCoF following credible contingency events on the mainland and Tasmania. However, stakeholder submissions to the draft determination requested further implementation details once the standard commences, with Shell noting that:[53]

> Although [the RoCoF limit] could be interpreted as a planning standard, the Panel should consider that there may be a wide range of control limits that could be placed on the market to meet the standard.

The Panel understands that the introduction of these standards will not lead to significant operational changes in the near term. However, in the longer term it is expected that AEMO may need to take action to deliver sufficient inertia — or equivalent RoCoF control services — to meet the standard. Initially, the RoCoF standard would be expected to bind for operation of the Tasmanian region and for SA during islanded operation. The Panel notes that further work is required to better understand the materiality of the RoCoF limit binding and the associated costs of meeting this constraint.

3.1.5 The RoCoF requirements for non-credible contingencies relate to the technical capability of emergency frequency control schemes

Under frequency load shedding (UFLS) is an emergency frequency control mechanism intended to manage the effect of non-credible contingency events that overwhelm the containment ability of contingency FCAS. UFLS involves the automatic disconnection of load to rebalance the network and avoid a cascading generator outage.

As part of this analysis the Panel has considered:

- that UFLS is the last wall of defence against a collapse in system frequency
- the fact that dynamic UFLS approaches are already implemented in Tasmania
- the introduction of appropriate RoCoF limits for non-credible contingency and protected events.

Each of these points is described further below.

UFLS is the last wall of defence against a collapse in system frequency

UFLS is a crucial component of frequency control frameworks by being a cost-effective insurance mechanism against a cascading outage following a significant contingency event. The satisfactory performance of UFLS schemes can be degraded if system RoCoF is high enough to overwhelm the relay's reaction times.

53 Shell Energy, submission to the draft determination, p.2.

As part of its advice to the Panel, AEMO modelled the frequency outcomes in a South Australian island following a non-credible separation event (double circuit trip of the Heywood Interconnector) co-incident with a trip of a large IBR generating units of various sizes to induce various levels of RoCoF after separation.

The summary of AEMO's findings suggest that UFLS schemes generally:[54]

- appear to operate correctly at RoCoF of 1Hz/s or 2Hz/s
- show issues arising under some conditions at 3Hz/s
- should not be expected to operate successfully at 4Hz/s or 5Hz/s.

The Panel determined that the satisfactory performance of UFLS should guide the settings of RoCoF limits in the FOS for non-credible or multiple contingency events to minimise the risk of a cascading outage and a black system event.

Dynamic UFLS approaches are already implemented in Tasmania

As discussed earlier, the Panel understands that the Tasmanian power system differs from the mainland in many aspects. Due to those complexities, TasNetworks has already implemented various RoCoF controls that are particularly well suited to the needs of the regional network and help maintain system security following credible and known high-impact non-credible events (such as the credible loss of Basslink).[55] The Panel would not want to override those chosen settings.

The current settings in Tasmania are:[56]

1. If a RoCoF of greater than 0.75 Hz is detected within 250 ms (3Hz/s RoCoF): UFLS block 1 Relay will activate a measurement cycle at 49Hz.
2. The RoCoF limit is defined as 0.4Hz over 340ms. If the frequency change exceeds this limit then the relay will trigger UFLS block 1. Block 1 will therefore trigger from 48.6Hz.
3. Block 2 operates in the same way, though if the conditions of item (1) are met, the block 2 relay will activate a measurement cycle at 48.8Hz, triggering block 2 UFLS from 48.4Hz.
4. If item (1) criteria is not met, that is, if RoCoF is not measured at 0.75Hz over 250ms (3Hz/s), then UFLS block 1 will trigger at 48Hz.

The Panel's determination aligns the RoCoF standard for non-credible contingency events with the existing dynamic UFLS introduced by TasNetworks. In its submission to the draft determination, TasNetworks strongly endorsed the Panel's consideration of the current settings in Tasmania, stating:[57]

> The adoption of different RoCoF standards for Tasmania, recognising the different attributes of our current generation fleet, is fully endorsed.

54 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.40.

55 Ibid., pp.44-45.

56 Ibid.

57 TasNetworks, submission to the draft determination, p.1.

Appropriate RoCoF limits for non-credible contingency and protected events in the mainland and Tasmania

The revised FOS includes new RoCoF standards for non-credible contingency events or multiple contingency events in both the mainland and Tasmania. The Panel has amended the FOS to include the following obligation:

> Following a *non-credible contingency event* or **multiple contingency events** that is not a *protected event*, AEMO should use reasonable endeavours to maintain the **rate of change of frequency within**:
>
> - Mainland: ±3Hz/s (measured over any 300ms period)
> - Tasmania: ±3Hz/s (measured over any 300ms period).

The introduction of a RoCoF standard for non-credible contingency events was strongly supported by stakeholders in submissions to the draft determination.[58] In particular, the AEC recognised the value of the standard in assisting networks set parameters for satisfactory operation of their emergency frequency control schemes:[59]

> The AEC supports the introduction of a RoCoF standard which may; assist connecting parties in understanding system performance; assist the networks in setting UFLS speed; assist in determining parameters for a future inertia market.

The Panel has not included an explicit RoCoF limit in the FOS for protected events as matters relating to AEMO's operation of the power system can be considered, on a case-by-case basis, when initially declaring the event.[60] Such an outcome was supported by CS Energy in its submission to the issues paper:[61]

> There should not be a standard for protected events for the same rationale as to why protected events are not currently specified in the FOS but rather the FOS is applied to the protected event. It is anticipated that AEMO will consider RoCoF limits when defining the operational conditions of a protected event.

As for the existing requirements in the FOS for multiple contingency events, the RoCoF limit for a non-credible or a multiple contingency event is a 'reasonable endeavours' requirement. As noted by the Panel in its 2017 final determination, this 'reasonable endeavours' requirement reflects the impracticality of maintaining the power system RoCoF within the prescribed limits following the occurrence of all possible multiple contingency events.[62]

58 Submissions to the draft determination: CEC, p.1; TasNetworks, p.1; Origin, pp1-2; CS Energy, p.6; Shell Energy, p.1; Delta Electricity, p.1; AEC, p.4.

59 AEC, submission to the draft determination, p.4.

60 Clause 8.8.4(f)(3) of the NER.

61 CS Energy, submission to the issues paper, p.8.

62 Reliability Panel, Review of the frequency operating standard - stage one, final determination, 14 November 2017, p.31

3.2 RoCoF limits would support the valuation and provision of RoCoF control services

The introduction of a RoCoF standard in the FOS will promote efficient investment in and operation of energy resources by supporting the valuation and procurement of essential system services to manage post-contingency RoCoF such as:

- the implementation of new market ancillary service arrangements for fast frequency response (very fast raise and very fast lower services)
- the potential development of arrangements to procure RoCoF control services such as synchronous and synthetic inertia.

Each of these points is described further below.

3.2.1 The implementation of market ancillary services for fast frequency response

Due to the increased post-contingent RoCoF when operating the power system at low levels of inertia, faster acting frequency control services are required to arrest and stabilise the system frequency within the existing system FOS settings.

In July 2021, the AEMC made the *Fast frequency response market ancillary service* rule 2021 to introduce the two new FCAS services into the NEM. Although FFR cannot entirely replace the immediacy of an inertial response, the new services will respond more quickly to power system disturbances to help maintain system security during periods of lower inertia operation. The markets for the new FFR services will commence on 9 October 2023 with the RoCoF standard assisting in the specification and dispatch of the services.

The value of a RoCoF standard in guiding the specification and procurement of FFR was identified by stakeholders in submissions to the issues paper and draft determination.[63] CS Energy in particular noted that:[64]

> We support the draft decision to introduce a rate of change of frequency (RoCoF) standard which could be used to guide the modelling of Very Fast frequency control ancillary services (FCAS) requirements.

Potential future arrangements for the valuation and procurement of RoCoF control services

Implementing a RoCoF standard as part of the FOS could also inform the consideration of future arrangements to support the provision of RoCoF control services. Such arrangements are currently being considered by the AEMC through the following rule change projects:

- Through the *Operational security mechanism* rule change, the Commission is considering a new mechanism for the procurement and scheduling of system security services and configurations to support the secure operation of the power system.[65] This includes the development of new arrangements to price, procure and schedule resources that deliver

63 Submissions to the issues paper: EnergyAustralia, p.3; TasNetworks, p.4; CS Energy, p.8; Submissions to the draft determination: CS Energy, p.6; Origin, pp.1-2.

64 CS Energy, submission to the draft determination, p.6.

65 See: https://www.aemc.gov.au/rule-changes/operational-security-mechanism

security services. The RoCoF standard could inform AEMO on the secure level of system inertia, which would guide the procurement of security services.

- Through the *Efficient provision of inertia* rule change, the Commission is currently consulting on an AEC proposal to develop new market ancillary service arrangements for inertia.[66] It is understood that the proposed market would provide a vehicle to investigate and develop enduring arrangements for the provision of RoCoF control services to meet the future needs of the power system. A standard for RoCoF in the FOS could provide guidance on the level of inertia AEMO required to maintain system security, which would be an important input to the development of enduring arrangements for the provision of RoCoF control services.

Stakeholder submissions to the draft determination generally supported the interaction between the RoCoF standard and the procurement of inertia. [67] However, the CEC noted that the Panel needs to consider the somewhat circular justification that could underpin the procurement of inertia, raising that:[68]

> The Panel should consider how the RoCoF standard may affect the volumes and sources of pre-contingency inertia, since it would be ironic if systemic RoCoF risks, which are partially created by the dispatch of some synchronous thermal units, are then managed by paying those same units for the provision of inertia. As such, the Panel should provide AEMO with more guidance on how it intends to operationalise the RoCoF standard to avoid this perverse outcome.

The Panel agrees with the concerns raised by the CEC that there is the possibility of undesirable outcomes due to the interaction between the RoCoF limits for credible contingency events relying on the ride-through capabilities of synchronous generation and the operational procurement of inertia. Moreover, it is conceivable that synchronous units with weaker RoCoF ride-through capabilities could be constrained on to provide inertia to insure against the risk that they contribute to. The Panel notes that widening the RoCoF limits in the FOS would likely deliver net long-term benefits to consumers subject to the capabilities of connected generators. As outlined in section 1.3, the Panel expects that RoCoF withstand capability in the generation fleet could increase over time and this would support the Panel's consideration of a wider setting for the system RoCoF limits in the FOS at a future date. The Panel expects that the initial RoCoF limits in the FOS for the mainland could be increased at a later date subject to confirmation of increased RoCoF withstand capability of the generation fleet. The Panel will continue to monitor frequency performance and related developments through its Annual market performance review and recommends a follow up review of the FOS be completed by no later than the end of 2027.

The Panel is also aware that RoCoF withstand capability is a component of the cost recovery arrangements for the RoCoF Control Service in the Wholesale Electricity Market (WEM).[69]

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

67 Submissions to the draft determination: CS Energy, p.6; AEC, p.4.

68 CEC, submission to the draft determination, p.2.

69 Under the SWIS RoCoF Control Service Generators capable of withstanding a RoCoF greater than 1.5Hz/s will not be liable for any costs under the proposed mechanism.

Such an arrangement in the NEM may preserve the incentive for generators to improve their withstand capability. The Panel expects that the AEMC will consider these complexities as part of the *Efficient provision of inertia* and *Operational security mechanism* rule changes.

3.3 The form of the RoCoF standard

The RoCoF standard in the revised FOS is consistent with that set out in the draft FOS, however the drafting of the standard has been revised in response to stakeholder feedback. A number of submissions noted that specifying the RoCoF limit in the form "0.5Hz measured over any 500ms (1Hz/s)" had the potential to create confusion and that a more direct specification in Hz per second would be easier to interpret.[70]

The Panel recognises the importance of clarity in the FOS and has reflected this in the final drafting for the RoCoF limit. The drafting approach in the revised FOS aligns with the formulation of the RoCoF withstand requirements in the minimum and automatic access standards.[71] The revised FOS states:

> Following a *credible contingency event* (which may be a **generation event**, a **load event** or a **network event**), the **rate of change of frequency** must not be greater than:
>
> - Mainland: ±1Hz/s (measured over any 500ms period).
> - Tasmania: ±3Hz/s (measured over any 250ms period).
>
> Following a *non-credible contingency* event or **multiple contingency event** that is not a *protected event*, AEMO should use reasonable endeavours to maintain the **rate of change of frequency** within:
>
> - Mainland: ±3Hz/s (measured over any 300ms period).
> - Tasmania: ±3Hz/s (measured over any 300ms period).

70 For example, submissions to the draft determination: Delta Electricity, p.1; Shell Energy, p.2.

71 Clause S5.2.5.3 of the NER.

4 LIMITS AND THRESHOLDS ON CONTINGENCY EVENTS IN THE REVISED FOS

BOX 4: KEY POINTS IN THIS SECTION

Maximum contingency size for Tasmania

- The **revised FOS** extends the 144MW generation event limit to apply to load and network events in Tasmania. This limit is necessary to address specific challenges in managing the island's power system and provide transparency to connecting parties, such as proposed hydrogen electrolysers and data centres, as to the hosting capacity of the grid.

Maximum contingency size for the mainland

- The Panel decided that a limit in the FOS on the maximum contingency size for the mainland is not justified at this time as existing arrangements under the NER are sufficient to maintain the risks associated with increasing contingencies and more flexible mechanisms exist by which transparency can be improved in the mainland NEM.

Thresholds for a generation event in Tasmania

- The Panel has revised the definition of a generation event in Tasmania from 50MW to 20MW to align with the threshold for a load event. As noted in AEMO's submission to the draft determination, this reflects the specific operational conditions in Tasmania.
- The FOS now defines a generation event as:

    1. a *synchronisation* of a *generating unit* of more than the generation event threshold of;

        (a) for the **Mainland**: 50MW

        (b) for **Tasmania**: 20MW.

    2. an event that results in the sudden, unexpected and significant increase or decrease in the *generation* of one or more *generating systems* totalling more than the generation event threshold for the region in aggregate within no more than 30 seconds; or

    3. the *disconnection* of *generation* as the result of a *credible contingency* event (not arising from a **load event**, a **network event**, a **separation event** or part of a **multiple contingency event**), in respect of either a single *generating system* or a single *dedicated connection asset* providing *connection* to one or more *generating systems.*

The changing nature of operational risks that must be managed to maintain the system in a secure operating state is an important consideration as the power system transforms. AEMO identified a number of gaps in the *Engineering framework* for potential actions to meet the needs of the power system over the next ten years.

Additional details on the security and economic implications of contingency size limits and the Panel's considerations are available in section 3.2 of the draft determination.

4.1 The revised FOS extends the 144MW generator contingency size limit in Tasmania to include load and network events

The Panel has confirmed the existing 144MW limit on the maximum allowable generation event in Tasmania and extended the limit to also cover load and network events. AEMO's advice informed the Panel's final determination that the contingency size limit in Tasmania:

- supports system security
- sets clear expectations for the new grid connections.

Stakeholder responses were generally supportive of this element of the draft determination.[72]

4.1.1 The contingency size limit supports system security in Tasmania

The Panel's final determination extends the existing limit for the largest allowable generation event for the Tasmanian region in the FOS to support the secure operation of the Tasmanian power system.

The limit on the size of the largest generation event in the Tasmania power system was included by the Panel following the 2008 review of the FOS for Tasmania. Supported by advice from AEMO, this element of the FOS reflects the particular challenges associated with operating the Tasmanian power system including its relative small size and the scarcity of fast-acting contingency reserves.[73]

In 2019, the Panel reaffirmed the limit and revised the drafting to clarify where the limit is to be measured, that the limit applies in absence of network outages, and that the arrangements allow for the limit to be met in relation to one or more generating systems with a combined capacity in excess of 144MW.[74]

The Panel considered whether it would be viable to increase the limit on the size of the largest credible contingency event in Tasmania, as proposed by Woolnorth Renewables, and notes the reasoning provided in its submission to the issues paper. Raising the current limit from 144MW to 155MW would allow for the Musselroe Wind Farm — owned by Woolnorth Renewables — to operate unconstrained at all times, as was the case during the period July 2013 to January 2020. Woolnorth noted that:[75]

> WNR calculated the annual loss in revenue, as a result of this limit, is over $1.0M.

72 For example submission to the draft determination: TasNetworks, p.2.

73 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, pp.50-51.

74 Reliability Panel, Review of the Frequency Operating Standard - Stage two, Final Determination, 18 April 2019, p.12.

75 Woolnorth Renewables, Submission to the issues paper, p.5.

The Panel understands that a new generator contingency scheme commenced operation in Tasmania in December 2021, allowing Musselroe Wind Farm to operate without constraint when sufficient load tripping services are available.[76]

AEMO's advice to the Panel recommended that the existing 144MW limit on generation events for Tasmania be maintained and that the limit be extended to also apply to single network and load events. AEMO concluded that:

> Increasing or removing the limit would expose Tasmania to operational risks that cannot be adequately managed at this time.

Moreover, AEMO confirmed that load tripping and generator raise ancillary services are limited in Tasmania and that a single generator contingency cannot securely exceed the volume of available load tripping or FCAS.

Therefore, supported by advice from AEMO, the Panel has determined to maintain the existing limit of 144MW to help manage operational security risks in Tasmania in the context of the small size of the Tasmanian system and the relative scarcity of fast acting contingency reserves in Tasmania.

The contingency size limit has been extended to include network and load events

Both AEMO and TasNetworks support the Panel extending the generator size limit to apply to load and network events. TasNetworks noted in its submission to the draft determination that:[77]

> The extension of the existing 144MW limit for generation events in Tasmania to also apply for load and network events is also fully endorsed. This change will help manage the risks associated with the connection of large commercial and industrial loads such as hydrogen electrolysers and large-scale data centres.

The justification for extending the limit to apply to load and network events mirrors the reason for the generator event limit. The availability (and cost) of fast lower FCAS and the increasing levels of inertia required to minimise the increase in post-contingency RoCoF are both particularly hard to come by in Tasmania.[78]

Importantly, the Panel does not consider that expanding the limit would have a cooling effect on investment decisions in Tasmania. Large loads would continue to be able to connect to the network by designing their plant or network to comply with the limits specified in the FOS, as confirmed in the AEMO advice:[79]

> [The contingency size limit] will not, of course, limit or prevent load intensive industries from connecting large plants in Tasmania. The plant design may need to account for separate circuits within the plant to avoid a single point of failure greater

76 TasNetworks, submission to the issues paper, p.5.

77 TasNetworks, submission to the draft determination, p.2.

78 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.51.

79 Ibid.

> than 144MW from both a load or network perspective.

4.1.2 The contingency size limit in Tasmania sets clear expectations for new connections

By including a limit in the FOS, the Panel is sending a transparent signal to generators and loads of the hosting capacity of the relatively small Tasmania grid and the scarce availability of ancillary services. By setting clear expectations for connecting generators and loads, the Panel is providing transparent guidance on the technical hosting capacity for the Tasmanian grid and thereby reducing the likelihood of unexpected outcomes and delays during the connection process.

4.2 The revised FOS does not include a limit on the size of credible contingency events in the mainland

Given the changing nature of the risks in the power system, as captured by AEMO's *Engineering framework*, the Panel has investigated the expected costs and benefits of introducing a maximum contingency size limit for the mainland.

The Panel concluded that, despite the uncertainties and risks identified by AEMO from expected future power system developments, it is not appropriate to introduce a generation event limit in the FOS for the mainland NEM at the current time, as:

- current security arrangements under the NER are sufficient to manage operational security on the mainland, and
- the introduction of a firm limit in the FOS would be inflexible and could dissuade investors from developing large projects, thereby potentially compromising economic efficiencies.

Submissions to the draft determination strongly supported the Panel's rejection of maximum contingency size for the mainland as it would discourage investments in generation.[80] This view was expressed in the Origin submission:[81]

> The draft decision not to impose a maximum contingency size limit for the mainland is also appropriate, as such a limit could discourage investment in new generation projects.

4.2.1 Current arrangements under the NER are sufficient to maintain security in the mainland

The Panel has concluded that existing arrangements under the NER are sufficient to maintain system security on the mainland and that it is unlikely that a generator event limit would lead to a material improvement. The Panel determined that:

- the existing automatic and minimum access standards are sufficient to ensure that system security is not compromised
- the scale of the mainland power system and the increased volume of FCAS available diminish the vulnerability of the system to contingency events.

80 Submissions to the draft determination: CEC, p.1; Origin, p.1; CS Energy, p.6; Shell Energy, p.3; AEC, p.4.
81 Origin, submission to the draft determination, p.1.

Most stakeholder submissions to the draft determination strongly supported the Panel's final determination to not introduce a maximum contingency size limit for the mainland as current arrangements are sufficient to manage the associated risks.[82] The AEC's submission stated that:[83]

> The AEC concurs that the FOS is not necessarily the best place to promulgate a maximum contingency size [limit].

The existing connections process takes into account risks to system security

In the NEM, generators are expected to meet the automatic access standards, including those which specify that a generating system must have plant capabilities and control systems that are sufficient so that they do not result in a reduction in inter-regional or intra-regional power transfer capability.[84]

Importantly, the existing process considers factors other than frequency, such as voltage and power transfer capability, to fully determine the hosting capacity of the network at a specific location.

GHD's survey found that it is unusual for a jurisdiction to formally adopt a largest credible contingency size limit in their security standards as the risk is usually managed through the connections process. Only Great Britain formally specified an explicit contingency size limit in their security standards, with most jurisdictions managing contingency size risk through the connections process.[85]

The greater scale and availability of FCAS allows for a more flexible approach

The scale, generation mix and availability of affordable FCAS on the mainland distinguishes the system from the Tasmanian grid. The Panel considers that the mainland network is much more capable of leveraging market mechanisms to manage operational risks from large credible contingency events due to a relative abundance of fast-acting FCAS when compared to Tasmania.

AEMO's advice to the Panel confirmed the considerable complexities involved in managing the Tasmanian grid, as:[86]

> The Tasmanian power system differs from the mainland in many aspects with its own complexities. This often results in separate, independent FOS requirements applicable to Tasmania's unique scenario. Raise and lower FCAS availability is scarce. Often in high wind periods, hydro plants are run on minimum generation and are unable to lower.

82 Submissions to the draft determination: Origin, p.1; CS Energy, p.6; Shell Energy, p.3; AEC, p.4.

83 AEC, submission to the draft determination, p.4.

84 Clause S5.2.5.12(a) of the NER.

85 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.32.

86 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.43.

4.2.2 A limit on contingency sizes for the mainland would be inflexible

The Panel determined not to include a generation event limit for the mainland NEM in the revised FOS as it would be an inflexible way to account for system needs. A firm generation event limit would not:

- account for the other limiting factors that need to be considered as part of the connections process
- adequately consider regionally specific network characteristics
- be able to be updated sufficiently frequently to recognise changes in the operating envelope of the network.

The Panel concluded that there is not sufficient value, a great deal of complexity and a lack of flexibility in setting a limit for the mainland. Moreover, the Panel agrees with several stakeholder submissions that raised concerns that such a limit would dissuade investments in large scale generation projects.[87] Origin concluded that:[88]

> The draft decision not to impose a maximum contingency size limit for the mainland is also appropriate, as such a limit could discourage investment in new generation projects.

Frequency is rarely the sole factor in the connections process on the mainland

AEMO's advice confirmed that the characteristics of the mainland grid, with its greater geographical size and with a wider diversity of generation resources, means that the limiting factor when connecting generators is not always frequency related. AEMO noted that:[89]

> Limiting factors were not always frequency related. Localised sub-regional restrictions were often limited by voltage related matters and there were also thermal limitations in many areas, which should be dealt with using constraints on the dispatch of the plant.

As such, the Panel concluded that introducing a firm limit in the FOS would give connecting generators a false sense of confidence that their proposed arrangements would be sufficient to fulfil the connection requirements under the NER. The connection process that requires a myriad of other factors to be taken into consideration, is outside the remit of the Panel.

A contingency size limit would need to reflect regional characteristics

The Panel is aware that a single contingency size limit for the mainland may not adequately represent regional characteristics and hosting capacities. Instead, the Panel would be required to determine regional or sub-regional limits in order to provide investors with clarity on the design or size of generators that the system is capable of hosting.[90] AEMO's advice concluded that:

87 Submissions to the draft determination: Origin, p.1; CS Energy, p.6; Shell Energy, p.3; AEC, p.4.
88 Origin, submission to the draft determination, p.1.
89 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.31.
90 Ibid., p.52

> A value for South Australia would not be the same as Queensland. Connection size limits due to localised network hosting limitations may also be needed sub-regionally. For example, a contingency limit in outback New South Wales will be different to a contingency limit for Newcastle.

As such, the Panel determined that a generator event limit in the FOS would not serve the interests of market participants. Instead, the existing negotiation process under the rules is more capable of reflecting regional particularities.

A limit in the FOS would not be sufficiently flexible to reflect network upgrades

In order to reflect this rapidly evolving transmission and distribution networks, the Panel would be required to continuously review any contingency limits for the mainland.[91] The Panel does not consider that the FOS would be reviewed frequently enough to adequately update contingency size limits to reflect changes to the hosting capacity of the network. Instead, the Panel concluded that NSPs are better positioned to flexibly adjust network hosting capacities as the system evolves.

AEMO and TNSPs are best placed to manage the risk of large contingencies

These findings show that it would be difficult for a specification in the FOS to adequately reflect the geographical differences and evolving technical capabilities of network equipment in different regions on the mainland at present time, or in the future.

As such, the Panel's determination is that it is more appropriate for TNSPs and AEMO to coordinate the connection of and manage the operational risks posed by large generators and loads on a case-by-case basis. Maintaining the current approach provides market participants with greater flexibility when compared to a rigid limit in the FOS, that could remain in force for a considerable amount of time.

The Panel considers that it could be in the interests of consumers for the Commission to consider implementing an explicit co-optimisation of marginal FCAS costs and increasing contingency sizes, as done in the WEM in Western Australia. By dynamically allocating the costs of ancillary services to facilities generating higher quantities and those with a poor reliability history, NEMDE would automatically allocate costs to those most suitable to bear them thereby resulting in an optimal outcome for consumers.

The outcome of GHD's survey found that such an optimisation process naturally disincentivises generators from a connection that would increase the size of the largest credible contingency as:[92]

> … the optimisation performed by the market dispatch engine may choose to constrain a larger generator if that results in the least cost dispatch outcome considering the co-optimised energy and essential system service markets.

91 Ibid.

92 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.32.

4.2.3 Guidelines explaining the hosting capacity of the mainland NEM should increase transparency

A limit in the FOS would have provided a clear and transparent investment signal to market participants on what the hosting capability of the network is. In its advice AEMO agreed, noting:[93]

> A transparent MW credible contingency size limit for the mainland would be of value to guide new project sizing, particularly in the connections process.

The Panel agrees that increased transparency and commentary to provide clear expectations to connecting parties could be of value. However, as explained above, there is not sufficient value, a great deal of complexity and a lack of flexibility in setting a limit for the mainland. Moreover, as noted in AEMO's advice, the limiting factor is often not frequency related. As such, a limit in the FOS may provide connecting parties with a false sense of confidence that the barriers to connecting to the grid have been alleviated.

Stakeholder submissions to the draft determination raised concerns surrounding the lack of transparency and predictability of the TNSP-led connections process. In its submission, the CEC stated that:[94]

> The decision to reject a maximum contingency size is also supported, on the basis of the potential impacts this could have on the renewable generation and storage investment pipeline. However, we agree with points made that maximum contingency sizes may continue to be imposed 'through the back door' of the connection agreement process, particularly through relatively opaque interpretations of NER clause S5.2.5.12.

This view was reinforced by the AEC's submission:[95]

> The AEC considers that greater predictability would be useful for investors, such as a published list of maximum contingency sizes in different locations of the NEM.

The Panel considers that a similar level of transparency could be attained through the development of guidelines by AEMO and mainland TNSPs. The guidelines, updated more periodically than the FOS, would provide investors and market participants with clear expectations on the hosting capacity of the network, taking into account network considerations other than frequency. This would allow connecting generators to design their plant to adhere to these requirements to conceivably simplify the connections process.

4.3 The revised FOS aligns the threshold size of generation and load events in Tasmania

The FOS includes separate definitions for a load event and a generation event. These definitions include a threshold size, in megawatts, that indicates the size of a contingency

93 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.44.

94 CEC, submission to the draft determination, p.1.

95 AEC, submission to the draft determination, p.4.

event above which the frequency may deviate outside the normal operating frequency band (NOFB) of 49.85 – 50.15 Hz.

AEMO procures frequency control ancillary services to maintain frequency within the NOFB by:

- utilising regulating FCAS to control the system frequency within the NOFB
- dispatching contingency FCAS to automatically react to rebalance supply and demand when frequency deviates outside the NOFB.

Following the previous review of the Frequency operating standard the minimum thresholds in the FOS were:

- Load event — 20MW (Tasmania) and 50MW (Mainland)
- Generation event — 50MW (Tasmania and the Mainland).

The issue being considered here is the relationship between the size of an interconnected region and the size of a contingency event that would be expected to result in a frequency deviation of a certain amount. In general, a larger power system requires a larger imbalance of supply and demand (a larger contingency event) to cause the same frequency deviation. The relationship between the variation of frequency in a power system and the size of a supply-demand imbalance is called frequency bias.[96]

4.3.1 The Panel has aligned the threshold for generation and load events in Tasmania at 20MW

The Panel's determination is to redefine the contingency event threshold size for generation at 20MW in Tasmania, aligning it with the definition of load event in the region. AEMO's submission to the draft determination proposed the change as:[97]

> Frequency operation in Tasmania is inherently different to the mainland due to a range of characteristics including a different energy mix, significantly smaller power system with lower inertia, relative scarcity of FCAS volume in Tasmania and a significant generation and load contribution from Basslink. The use of the same 50 MW threshold for a generation event is therefore not proportional and consistent in its application between the two regions.

The threshold of a generation event in Tasmania is unlikely to result in any material changes in the operation of the network as the settings do not drive the procurement of ancillary services in the region.[98] However, the Panel concurs that reducing the threshold for generation event to 20MW would be appropriate given the size, particularities and frequency bias of the Tasmanian system as outlined above.

96 Frequency bias is proportional to the quantity and type of generation and load equipment connected to the system at any time. AEMO currently use a static frequency bias for the mainland of 280MW/0.1Hz compared with 20MW/0.1 Hz for Tasmania.

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

98 Reliability Panel, Review of the frequency operating standard - stage two, final determination, 18 April 2019, p.33.

5 THE REVISED FOS DURING SYSTEM RESTORATION

BOX 5: KEY POINTS IN THIS SECTION

- **The revised FOS** renames the term "supply scarcity" as "system restoration". This revision better reflects the operational conditions for which this element of the FOS is intended to apply.
- The operational frequency tolerance band (OFTB) in the **revised FOS** is 49 – 51 Hz. This change standardises the OFTB for interconnected, island and system restoration in the mainland NEM. It will align the requirements for connecting generators under clause S5.2.5.3 of the NER with the expected system frequency outcomes in the FOS for system restoration.

The settings for supply scarcity were introduced as part of the 2009 review of the FOS to define the range of allowable frequency for the power system while load is being restored following a major power system incident on the mainland.[99] When originally introducing the settings for supply scarcity, the Panel considered the trade-off between benefits for consumers and the potential for any increased system security and reliability risks.

The Panel's assessment of the FOS that applies during supply scarcity was triggered by concerns raised by stakeholders that queried the appropriateness of the current settings in the FOS that apply for the purpose of load restoration at times of supply scarcity.[100] A reformatting of the FOS performed during the previous review has introduced more strenuous requirements for generators under the automatic and minimum access standards for responding to frequency disturbances.[101] Under the NER connections process, generators are required to be capable of operating continuously within the range of the operational frequency tolerance band (OFTB) for supply scarcity, 48 – 52 Hz, for at least the stabilisation time of 10 minutes.

As part of this final determination, the Panel has:

- Renamed "supply scarcity" to "system restoration" to clarify the purpose of the wider settings in the FOS. The updated language better reflects the aims of the initial settings to support the timely restoration of load following a large non-credible contingency event.
- Narrowed the OFTB during supply scarcity (revised to system restoration as part of this review) to 49 – 51 Hz to align the requirements for connecting generators with the expected frequency outcomes in the FOS during times of system restoration.

In determining these revised arrangements, the Panel has aimed to:

99 Reliability Panel, Application of Frequency Operating Standards During Periods of Supply Scarcity, Final Determination, April 2009, p.1.

100 Shell Energy, submission to the issues paper, p.4.

101 Clause S5.2.5.3 of the NER.

- improve the **secure** and **reliable** operation of the power system, in line with **consumer preferences**, by enabling an accelerated reconnection of load following a non-credible contingency event
- **reduce** the costs incurred by generators connecting to the network while maintaining the requirements on generators to be capable of operating in time of system restoration
- provide AEMO with a greater range of **flexibility** when restoring the power system following major power system incidents while **minimising costs** over the longer term.

This section includes the Panel's consideration of the renaming of "supply scarcity" in the FOS, including:

- Section 5.1 — the renaming of this element of the FOS better aligns with the expected conditions
- Section 5.2 — the operational frequency tolerance band (OFTB) during system restoration.

Additional details on the security and economic implications of the settings for system restoration and the Panel's considerations are available in section 3.4 of the draft determination.

5.1 The renaming of this element of the FOS better aligns with the expected conditions

In the current FOS, the term "supply scarcity" refers to a mode of operation where, following a contingency event, the frequency has reached the applicable recovery band and AEMO considers the power system is sufficiently secure to begin the re-connection of load.[102] Under this mode of operation, frequency performance requirements are relaxed to enable AEMO to prioritise the re-connection of load over tight frequency control. The Panel determined to rename "supply scarcity" to "system restoration" to better reflect the purpose of the wider bands and minimise confusion.

The use of the phrase "supply scarcity" appears to be a misnomer which has a different meaning in general language when compared to the definition in the FOS. It has led to an understandable misinterpretation of the band's purpose and a reasonable questioning of why a generator would need to show the capability of uninterrupted operation at 52 Hz if supply of electricity is "scarce".

AEMO's advice to the Panel corroborated this view and confirmed its understanding of the purpose of the wider settings, stating that:[103]

> The technical requirements for the 'supply scarcity' frequency band are sound and required. That is, during load restoration following a contingency event, meaning:
>
> 1. A significant contingency event has occurred. FOS applied to the event, applicable for the event.

102 Supply scarcity (system restoration) applies both for the mainland and an electrical island.

103 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, pp.49-50.

2. There was considerable load shedding as a result of the contingency event.
3. The event has passed and AEMO is restoring the power system so load can be reconnected and the 'supply scarcity' FOS applies from this point, until the system is restored.

AEMO advised that the settings in the FOS that apply for "supply scarcity" be maintained, but that this element of the FOS be renamed to "system restoration", to avoid confusion as to the expected operational conditions for which this part of the standard applies.[104]

5.1.1 Wider system restoration settings allow for an accelerated re-connection of load following a large contingency event

The Panel introduced the settings for supply scarcity as part of the 2009 review of the FOS based on advice from the then system operator, NEMMCO, that the introduction of wider settings was in the best interests of consumers by accelerating the re-connection of load following significant contingency events.[105] The final determination concluded that:[106]

> The Panel considers that relaxing the FCAS requirements during a load restoration period will make more generator capacity available to supply customers. This is expected to allow NEMMCO to restore supply at a faster rate, thus reducing the impact on customers following a significant multiple contingency event.

As part of the current review, the Panel reexamined the settings and concluded that a wider operational frequency tolerance band (OFTB) is still in the best interests of consumers as it would enable the length of any disruption to energy supply to be minimised for end-use consumers. The more comprehensive generator withstand capabilities, confirmed during the connections process, would allow AEMO to confidently tolerate more volatile frequency without needing to acquire further contingency FCAS reserves as it initiates a system restart.

5.1.2 The Panel acknowledges stakeholder suggestions that "load restoration" is more suitable than "system restoration"

The draft FOS renamed the settings for supply scarcity to "system restoration" for the reasons outlined above. While stakeholder submissions broadly supported renaming this element of the FOS, a number of submissions proposed alternative names including "load restoration" or "consumer load restoration".[107] In its submission, CS Energy noted that:[108]

> CS Energy agrees with the intent in renaming the settings for "supply scarcity" but disagrees that it should be to "system restoration" as this is associated with system black which is not necessarily the case and most likely an electrical island outcome where there is a shortfall of available FCAS. CS Energy suggests that "load restoration"

104 Ibid.

105 From 1 July 2009 NEMMCO ceased operations with the roles and responsibilities transferred to AEMO.

106 Reliability Panel, Application of Frequency Operating Standards During Periods of Supply Scarcity, Final Determination, April 2009,p.13

107 Submissions to the draft determination: Delta Electricity, p.1; CS Energy, p.7. Shell Energy, p.2.

108 CS Energy, submission to the draft determination, p.7.

would be a more appropriate name for the settings as it is the key objective.

While the Panel acknowledges stakeholder suggestions for alternative names for this element of the FOS, it has determined to that this element of the FOS be named as "system restoration" . This is consistent with the draft determination and AEMO's advice that "system restoration" is a more suitable choice as load restoration is a common activity that could easily be misinterpreted by operations staff.

5.2 The operational frequency tolerance band (OFTB) during system restoration

The Panel has determined to revise the operational frequency tolerance band (OFTB) during system restoration in the mainland to 49 – 51 Hz, which standardises the OFTB for the mainland during interconnected, island and system restoration operating conditions.

The draft FOS proposed to maintain the OFTB at 48 – 52 Hz, based on AEMO's advice that it was necessary for the FOS to reflect that, during system restoration, frequency in the mainland system — or an island — may be expected to vary within this range of 50±2 Hz. However, further review by AEMO identified that this setting for the OFTB would lead to an inconsistency between the expected frequency outcomes for the power system, and the required frequency withstand capability for connecting generators under the NER.[109]

As noted in AEMO's submission to the draft determination, updating the OFTB to 49 – 51 Hz will standardise the OFTB across all expected modes of system operation and resolve an inconsistency that arises from the current settings whereby connecting generators must demonstrate a withstand capability that exceeds the expected system frequency outcomes.[110] Under clause S.5.2.5.3 of the NER connecting generators must demonstrate a capability for continuous uninterrupted operation within the frequency range defined by the widest setting for the OFTB for the longest recovery time defined in the FOS. Therefore, the OFTB in the FOS for system restoration of 48 – 52 Hz drove a requirement for generators to demonstrate a capability to withstand frequency within the range 48 – 52 Hz for 10 minutes to achieve both the automatic and minimum standard.[111] At the same time, the FOS specifies the worst case expected system frequency outcomes for the mainland as being during system restoration for a multiple contingency event – for this condition the frequency shall be:[112]

- contained within 47 – 52 Hz (reasonable endeavours)
- stabilised to within 49 – 51 Hz within 2 minutes
- recovered to within 49.5 – 50.5Hz within 10 minutes

Therefore, while it is expected that system frequency would be stabilised to 49 – 51 Hz within 2 minutes, the specification of the OFTB for system restoration at 48 – 52 Hz drove a

109 AEMO, submission draft determination, p.2.
110 Ibid.
111 Clause S5.2.5.3 of the NER.
112 Table A.5 of the Frequency operating standard

requirement for connecting generators to demonstrate the capability to withstand frequency within the range of 48 – 52 Hz for up to 10 minutes — the recovery time.

To remedy this inconsistency, in its submission AEMO proposed that:[113]

> Table A1 of the FOS be revised to clarify that the OFTB for the mainland NEM is 49 – 51 Hz for interconnected, island and system restoration conditions. The OFTB for Tasmania should remain unchanged as 48 – 52 Hz for interconnected and island operation.

The Panel agrees with AEMO's assessment that setting the OFTB for system restoration at 48 – 52 Hz was an error. Therefore, the OFTB for the mainland during system restoration in the revised FOS is 49 – 51 Hz. This change will resolve the inconsistency outlined above by aligning the performance requirements for connecting generators with the expected frequency outcomes during system restoration. The Panel considers that this change will flow through to material reductions in cost for connecting generators with a negligible impact on system security.

113 AEMO, submission draft determination, p.2.

6 THE SETTINGS FOR FREQUENCY PERFORMANCE DURING NORMAL OPERATION

BOX 6: KEY POINTS IN THIS SECTION

- Modelling undertaken by GHD demonstrates net economic benefits for electricity consumers by maintaining a narrow setting for the PFCB — such that frequency is tightly controlled around 50 Hz. The benefits of controlling frequency tightly around 50Hz include increased power system resilience and reduced aggregate costs for frequency control.
- A narrow setting for the PFCB **promotes power system security and resilience**, by:
  - effectively controlling power system frequency to 50 Hz
  - reducing the risk and volume of load shedding following non-credible contingency events
  - increasing the likelihood of rapid re-synchronisation of islanded regions following separation events
  - supporting stable operation through distributed control that is immune to mal-operation of centralised control and communication systems (AGC — SCADA).
- A narrow setting for the PFCB supports the **efficient investment in**, and **operation of** the power system by reducing the overall work done (and the associated costs) to control power system frequency during normal operation.
- Maintaining the NOFB at the current setting is necessary and appropriate under the current market and regulatory arrangements, where there is a reliance on mandatory PFR to deliver effective frequency control and there are no other tools at AEMO's disposal to adjust the level of aggregate frequency responsiveness in response to the changing system needs over operational time frames.
- The Panel considers that it will be appropriate for this element of the FOS to be revisited in the future, following a suitable period of operational experience with the new Frequency performance payments arrangements in place. Given that these incentive arrangements are due to take effect on 8 June 2025, the Panel considers that a subsequent review of the FOS should be completed by no later than the end of 2027.

The revised FOS includes the following additional requirements for the mainland and Tasmania:

- confirmation that the target frequency for the mainland and Tasmania is 50 Hz
- confirmation of the primary frequency control band (PFCB) as 49.985 - 50.015 Hz (consistent with the initial setting in the NER)

The revised FOS maintains the following existing requirements for the mainland and

Tasmania:

- the normal operating frequency band (NOFB) remains as 49.85 – 50.15 Hz
- the normal operating frequency excursion band (NOFEB) as 49.75 – 50.25 Hz.

Except as a result of a *contingency event* (which may be a **generation event**, a **load event** or a **network event**), **system frequency**:

a) must be maintained within the applicable normal operating frequency excursion band, and

b) must not be outside of the applicable normal operating frequency band for

more than 5 minutes on any occasion and not for more than 1% of the time over any 30-day period.

The settings in the FOS for normal operation establish the required frequency outcomes for the power system in the absence of contingency events. The energy market dispatches generation to match expected demand every five minutes. However, even in the absence of contingency events, variations in supply and demand within each dispatch interval can lead to a power imbalance that results in frequency moving away from the nominal target of 50 Hz. The control of frequency during these operating conditions is achieved through a combination of automatic primary frequency response (PFR) from individual generators and regulation services controlled through AEMO's automatic generation control (AGC) system.[114]

Importantly, the settings in the FOS that apply during normal operation also impact on the system outcomes following contingency events. For example, when the frequency is closer to 50Hz before a contingency event, then a wider buffer is established before frequency exceeds the technical limits of power system plant, which could lead to cascading failure and a black system event.

However, there are costs associated with the enablement and provision of system services used to control frequency to 50 Hz. These costs relate to the enablement and utilisation of regulation services and the delivery of PFR. PFR may be delivered as a consequence of the mandatory PFR arrangements that apply for scheduled and semi-scheduled generators or due to voluntary provision beyond the mandatory requirements.

The Panel notes that the AEMC has recently concluded a package of reforms to the NER related to the provision of PFR in the national electricity system. The AEMC's final rule, *Primary frequency response incentive arrangements*, confirmed that scheduled and semi-scheduled generators are obligated to provide PFR to help control power system frequency and support the resilience of the power system to contingency events.[115] It also introduces new incentive arrangements, through frequency performance payments, that will value

114 Further information on the fundamentals of power system frequency control is available in Appendix B of the issues paper.

115 AEMC, Primary frequency response incentive arrangements - Final Determination, 8 September 2022.

helpful frequency response provided in accordance with the mandatory arrangements. The Commission envisages that the frequency performance payments will also encourage voluntary action from generators and loads that will help control frequency into the future. The new frequency performance payments arrangements commence on 8 June 2025.

In submissions to the draft determination, several stakeholders requested that the Panel review the settings for normal operation prior to 2027.[116] Stakeholders considered that the settings should be reassessed and retuned regularly to meet required system outcomes and that the proposal to reconsider the settings following two years of operation of the PFR frequency performance payments is too far in the future. However, the Panel considers that the time would allow this future review to be able to account for the rapid rate of change in the power system and also to review the economic and operational outcomes following the commencement of the new frequency performance payments arrangements.

The remainder of this chapter is structured as follows:

- Section 6.1 — the target and allowable range for frequency performance during normal operation
- Section 6.2 — the primary frequency control band (PFCB)
- Section 6.3 — the Panel will monitor system frequency performance during normal operation and recommends a follow up review of these settings by no later than the end of 2027.

Additional details on the security and economic implications of settings for normal operation and the PFCB including the Panel's considerations are available in section 4 of the draft determination.

6.1 The target and allowable range for frequency performance during normal operation

The revised FOS maintains the following existing requirements that set the allowable range for frequency during normal operation in the mainland and Tasmania:

- the normal operating frequency band (NOFB) remains as 49.85 – 50.15 Hz
- the normal operating frequency excursion band (NOFEB) as 49.75 – 50.25 Hz.

In addition to maintaining these elements of the FOS, the revised FOS also includes a new requirement that the target frequency for the mainland and Tasmania is 50 Hz. This aligns with the one of the fundamental principles for operation of the power system, that the target frequency is 50 Hz, and reflects the objective of AEMO's Automatic generation control (AGC) system that provides central control of frequency regulation services.

The following section summarises stakeholder views in relation to the settings in the FOS for normal operation and the Panel's related final determination and FOS.

116 Submissions to the draft determination: AEC, p.2; Delta Electricity, p.4; Shell Energy, p.5.

6.1.1 Stakeholder views on the settings in the FOS for normal operation

Most stakeholders welcomed the Panel's review of the settings in the FOS for normal operation and the PFCB and generally accepted that frequency performance in the NEM has improved significantly following the introduction of mandatory narrow band PFR and the initial narrow setting in the NER for the PFCB of 49.985 – 50.015 Hz.[117]

Some stakeholders consider that the operational outcomes associated with the current settings should be maintained, i.e. that the operational and resilience benefits justify frequency being controlled as close as is reasonably practical around 50 Hz.[118] EnergyAustralia noted that the current frequency performance in the NEM — relative to the NOFB — implied that the current setting for the PFCB may be too narrow and/or that the current setting for the NOFB may be too wide.[119]

The issues paper sought stakeholder feedback on potential approaches to reflecting a target for a narrower frequency distribution in the FOS, consistent with the observed frequency distribution in the NEM prior to 2015 and following the re-introduction of narrow band PFR in 2020.[120] However, stakeholders expressed reservation with respect to these proposals, noting that the focus of the Panel's assessment should be on investigating the costs and benefits of controlling frequency closer to or further away from 50Hz. Stakeholders highlighted the importance that the Panel's determination should aim to balance the benefits of tight frequency control with the costs of achieving this outcome and that the Panel's consideration of the PFCB and NOFB be supported by independent economic analysis.[121]

For example the AEC noted that:

> it is incumbent on those who prefer tighter frequency performance to identify and quantify exactly what system security benefits result from tighter standards such that the Panel can compare them to their costs of delivery.

Similarly, in relation to the NOFB, Energy Australia noted:[122]

> exact values to be determined via rigorous, independent economic assessment. This should include consideration of:
>
> - the trade-offs and synergies possible under various wider PFR settings,
> - the technical and commercial realities of both current and future generation mixes, and
> - customer insights on acceptable frequency performance.
>
> Lacking such analysis, it is unclear how the optimal balance between security, financial, efficiency and operational concerns can be achieved. Nor how the long-term interests

117 Submissions to the issues paper: AEC, p.1; Energy Australia, p.1-2; TasNetworks, p.3.

118 For example, TasNetworks submission to the issues paper, p.3.

119 EnergyAustralia, submission to the issues paper, pp.1-2.

120 Reliability Panel, Issues paper on the review of the frequency operating standard, pp.23-26.

121 Submissions to the issues paper: AEC, pp.2-3; Delta Electricity, p.2; EnergyAustralia pp.2-3; SnowyHydro, p.1; CS Energy, pp.2-7, Shell Energy, p.3; Iberdrola, pp.2-3; Origin Energy, pp.1-2.

122 EnergyAustralia, submission to the issues paper, pp.2-3.

> of customers can be maximised per the National Electricity Objective (NEO).

The Panel agrees that economic analysis on the costs and benefits of controlling frequency closer or further away from 50 Hz is an important input into its assessment of the NOFB. As such the Panel's final determination for the settings in the FOS during normal operation is supported by power system modelling and estimated economic impacts of varying the PFCB between 5 mHz and 500 mHz. The results of this analysis are described in section 6.2.

The Panel acknowledges the proposal that the FOS more closely specify the required frequency outcomes during normal operation

The Panel notes the concerns raised by generator submissions and the AEC with the process undertaken to review the settings for normal operation and a desire for the Panel to revisit the FOS to better reflect the expected frequency performance during normal operation. The AEC's submission questioned the Panel's process, recommending:[123]

> that the work performed to date by the Panel be redirected into re-specifying the NOFB rather than the PFCB. Work on the PFCB (or any other means to deliver the NOFB) would come later, consequential on the new NOFB.

The Panel notes that the results from the GHD analysis demonstrate a benefit to consumers through maintaining frequency tightly around 50 Hz. In line with the views expressed by the AEC, this analysis supports the consideration of a narrowing of the required frequency outcomes during normal operation; either through narrowing the NOFB or through the inclusion of additional bands within the NOFB to reflect the expectation that frequency be held more closely to 50 Hz. The Panel notes that such options were considered through this review, although ultimately not implemented through this determination.[124] The Panel notes that stakeholder submissions and AEMO's advice acknowledged that the narrowing of the NOFB does not have a strong justification nor is the inclusion of additional bands within the NOFB an immediate priority, as it may present unknown risks.[125]

Further, under the current regulatory arrangements, there is a reliance on mandatory PFR to deliver the required frequency outcomes. While the Panel expects that this situation will change with the commencement of the Frequency performance payments in June 2025, prior to that time AEMO would be unable to effectively modulate the level of aggregate frequency responsiveness to meet the narrower frequency standards. Therefore, the Panel has determined to maintain the NOFB at its current setting of 49.85 – 50.15 Hz for inter-connected operation in the mainland system. The Panel considers that the ongoing monitoring and reporting of aggregate frequency responsiveness combined with the commencement of the new incentive arrangements will support further consideration of the appropriate settings for normal operation in a subsequent review of the FOS to occur by no later than the end of 2027.

123 AEC, submission to the draft determination, p.2.

124 Reliability Panel, Issues paper on the review of the frequency operating standard, p.28.

125 Origin, submission to the draft determination, 2 February 2023, p.2; AEMO, Advice for the Reliability Panel's Review of the Frequency Operating Standard, 8 December 2022, p.22.

6.1.2 The revised FOS maintains the current allowable frequency ranges during normal operation and confirms the target frequency as 50 Hz

AEMO's advice is that the settings in the FOS that specify the allowable range for frequency during normal operation should remain unchanged at this time, but that the FOS should include a clarification that the target frequency in the power system is 50 Hz.

In relation to the allowable range from frequency during normal operation, AEMO notes that:[126]

- The NEM power system is in the early stages of a complete transformation of generation, transmission, distribution and consumer load technologies and operation. However, the physics, science and electrical engineering principles remain the same.
- Frequency is a critical technical property for the stability of the power system. Frequency control principles have not changed.
- Mandatory narrow band PFR enabled successful control of the NEM to be reinstated after a period of unacceptable poor control of frequency.
- The NEM power system is now in a strong position to enable a transition to renewable energy sources with a firm basis of known frequency control practices.
- Given the extreme volume of work to be completed by the energy industry to facilitate the transformation, amending the normal operation parameters of the FOS are not a priority at this point in time and changes could present unknown risks.

In relation to the clarification of the target frequency as 50 Hz, AEMO notes that:

- All calculations for frequency management, protection schemes, deviations etc. require a specific number not a range. All existing calculations use 50 Hz.
- It has always been accepted and understood that the NEM frequency target is 50 Hz, though it has never been explicitly stated.

The Panel accepts AEMO's view that there is not a case for changing the requirements in the FOS that specify the allowable range for frequency during normal operation and that the current settings appear fit for purpose. The Panel also accepts that providing clarity in the FOS that the target frequency for the power system is 50 Hz would align with existing operational and control objectives.

In explicitly defining the target frequency as 50Hz, the Panel does not expect that system frequency be maintained at 50 Hz at any cost. Rather, this target should be interpreted within the context of the broader operational requirements in the FOS and the NER. This includes that the NOFB and NOFEB specify the allowable range for frequency during normal operation consistent with the obligation defined in clause 4.2.2(a) of the NER which states that:

4.2.2 The power system is defined as being in a satisfactory operating state when:

126 AEMO, Advice for the Reliability Panel Review of Frequency Operating Standard, pp.21-22.

(a) the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band;

It is noted that there have been zero exceedances of the FOS for the mainland between Q4 2020 to Q3 2022, following the implementation of changes to generator control systems consistent with the Mandatory PFR rule. While this outcome may be interpreted as a sign of over provision of the PFR service, the analysis undertaken by GHD demonstrates net benefits to consumers through controlling frequency close to 50 Hz. Further consideration of the costs and benefits of controlling frequency close to 50 Hz is set out in section 6.2.

6.2 The primary frequency control band (PFCB)

The revised FOS confirms the PFCB at 49.985 – 50.015 Hz consistent with the initial setting for the PFCB in the NER. The confirmation of the PFCB at the current setting is supported by AEMO advice along with detailed independent analysis of the associated costs and benefits during normal operation and in the relation to power system resilience.

The remained of this section explores how:

- the PFCB drives the distribution of power system frequency
- a narrow setting for the PFCB delivers improved power system resilience
- a narrow setting for the PFCB delivers lower total costs for controlling power system frequency.

6.2.1 The PFCB drives the distribution of system frequency around 50Hz

Under the current market and regulatory arrangements in the NEM, the PFCB — through the mandatory PFR arrangements — drives the distribution of power system frequency. This means that a wider PFCB will result in a wider distribution of frequency around 50 Hz and a narrower PFCB will result in a narrower distribution of frequency. This relationship is driven by the current operational environment where scheduled and semi-scheduled generators have an operational frequency control requirement to provide PFR in accordance with the Primary Frequency Response Requirements (PFRR) specified by AEMO.[127] The PFCB sets a lower bound for the maximum allowable deadband that AEMO specifies for affected generators in its PFRR. The PFCB is defined in the NER as:

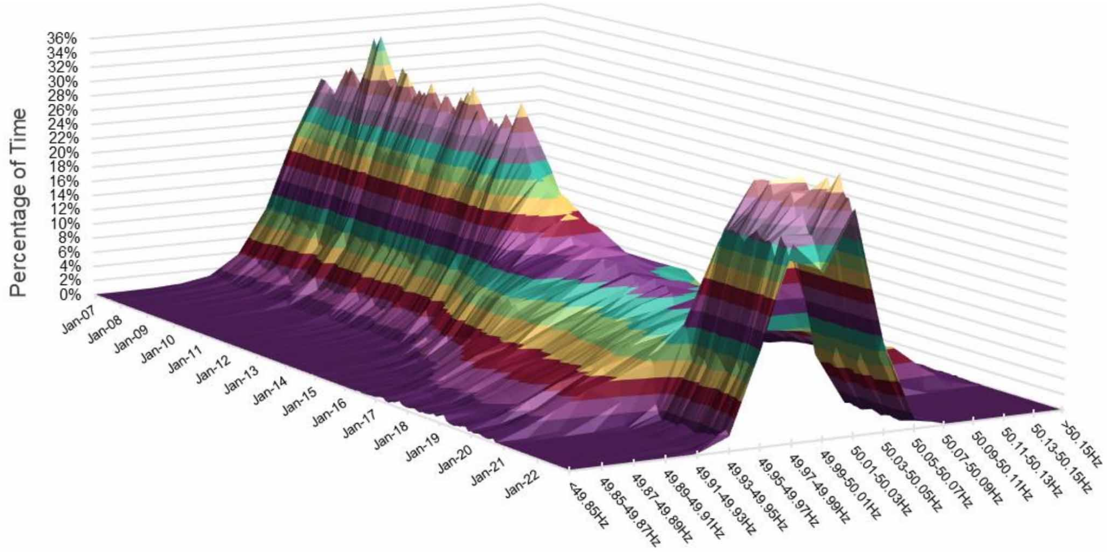
> the range 49.985 to 50.015 Hz, or other such range as determined by the Reliability Panel in the power system security standards.

The impact of the relationship between the PFCB and the distribution of frequency in the NEM is demonstrated in Figure 6.1. It is understood that prior to 2015 most generators in the NEM operated with zero range of insensitivity to changes in power system frequency. The degradation of the frequency distribution during the period 2015 – 2020 is understood to be

127 Clauses 4.4.2 and 4.4.2A of the NER.

due to a reduction in aggregate frequency responsiveness as a result of generators implementing changes to their controls systems to desensitise their active power response to deviations in power system frequency away from 50 Hz. The implementation of mandatory PFR in 2020 lead to a restoration of tight frequency control from 2021 onwards. This restoration of tight frequency control around 50 Hz was due to the coordinated reinstatement of narrow band PFR in 2020/21 which lead to a majority of the generation fleet narrowing their response "dead bands" to be close to the PFCB.

Figure 6.1: Frequency distribution in the NEM — January 2007 to September 2022



Source: AEMO, Frequency and Time Error Monitoring – Quarter 4 2022, February 2022, p.8.

The relationship between the PFCB and the distribution of frequency is further demonstrated through the results of the GHD analysis. This analysis looked at a range of different operational scenarios in the present power system and for the projected generation fleet in 2033 under AEMO's ISP step change scenario. The analysis considered periods of high and low renewable dispatch along with periods of high and low forecast error. The results of this analysis are available in the draft determination. They show a steady degradation in the quality of the frequency distribution as the generator frequency deadband is widened. This demonstrates that the PFCB — which aligns with generator control deadbands — sets the region of no control around 50 Hz. As the PFCB is widened, so too is the region of no control.

The frequency performance payments arrangements that will commence on 8 June 2025 are intended to complement the existing operational PFR frequency control requirements. However, the degree to which the frequency performance payments will drive increased provision of PFR leading to increased levels of aggregate frequency responsiveness in the power system will not be known until a suitable period has passed to allow for monitoring of the impact of the new arrangements. Therefore, as discussed in section 1.3, the Panel considers that the settings in the FOS that apply during normal operation, and the PFCB, should be revisited following a suitable period of operational experience with the new frequency performance payments arrangements in effect.

6.2.2 A narrow setting for the PFCB delivers improved system resilience

The Panel's final determination is supported by advice from AEMO and GHD that controlling frequency close to 50 Hz delivers value to electricity consumers through increased power system resilience. AEMO's advice is that the existing settings for the PFCB and normal operation are necessary to maintain effective control of frequency that is fundamental to a secure and resilient power system. This value is demonstrated in the following ways:

- Reduced risk and volume of load shedding due to less severe frequency nadirs following non-credible contingency events.
- Increased likelihood of rapid resynchronisation of islanded regions following separation events. This acts to shorten the restoration time following separation events leading to reduced market and customer impacts, including load shedding and costs of regional energy and FCAS procurement.
- Local distributed PFR provides redundancy in the event of failure or mal-operation of centralised control and communication systems (AGC – SCADA).

AEMO and TasNetworks both strongly supported the Panel's draft determination to retain the current settings for normal operation and the PFCB. In its submission:[128]

> AEMO also acknowledges the technical advice provided by GHD and supports the assessment and conclusions provided. GHD used power system modelling to analyse the operational and economic impacts of widening the PFCB from current defined settings of 49.985 Hz and 50.015 Hz. In doing so, the analysis found no technical or economic rationale to modify the current Primary Frequency Control Band (PFCB), as widening it would result in the deterioration of frequency control during normal operation, and in system resilience when contingency events occur.

The Panel concurs with the views expressed by AEMO that the GHD techno-economic advice found no justification for the widening of the PFCB. On the contrary, the modelling suggested such a measure would result in a profound deterioration of security and resilience outcomes while increasing aggregate frequency costs ultimately borne by consumers. The Panel notes that the grid is evolving rapidly and the appropriateness of settings should be reviewed again by no later than the end of 2027. This will allow for the Panel to reconsider these settings in the context of the frequency performance payments arrangements which are expected to encourage additional voluntary frequency responsiveness to help deliver effective frequency control.

Narrow PFCB settings reduce the risk and volume of under-frequency load shedding

The analysis undertaken by GHD demonstrates how widening the PFCB is likely to result in increased shedding of customer load following significant non-credible contingency events.

128 AEMO, submission to the draft determination, p.1.

The GHD analysis modelled a range of different non-credible events in the NEM based on the 2022 generation fleet and the projected generation fleet in 2033 under the ISP step change scenario.[129] The non-credible events studied included:

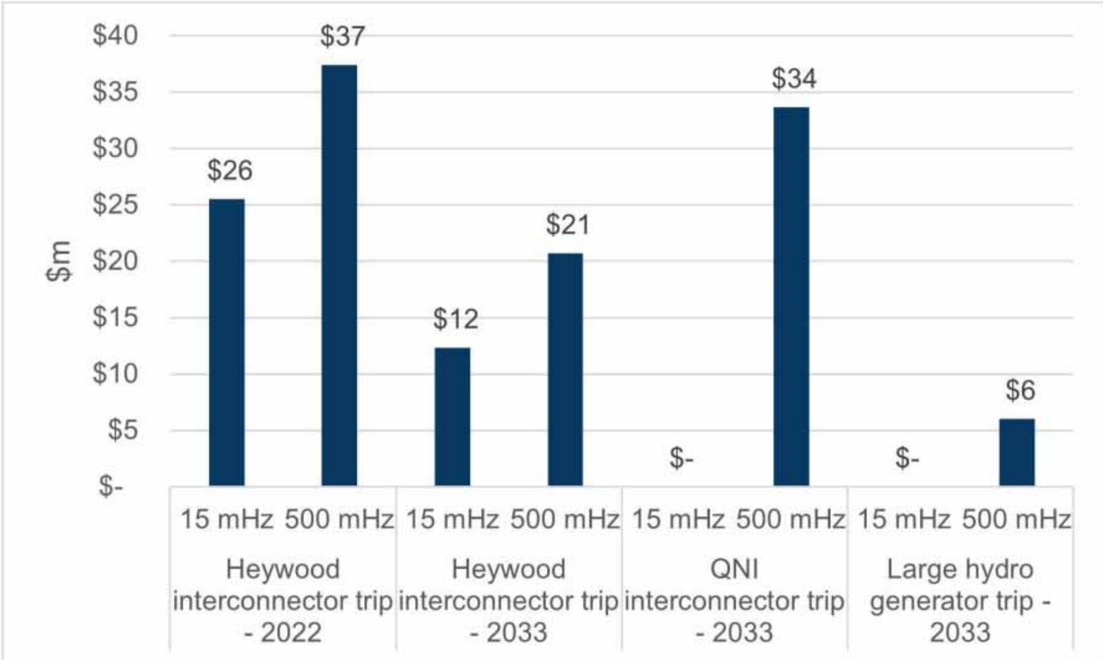
- Queensland separation with the loss of 1200 MW transfer from QLD to NSW on QNI.
- South Australia separation following the transfer of 650 MW from Vic to SA across the Heywood link.
- Simultaneous trip of a large level of generation — 2 x Loy Yang A units at full load (1130 MW).
- Trip of large NEM load — 600 MW of net load as per Western Downs – Columboola event.

GHD modelled the system outcomes for each of these non-credible contingency events to determine the power system frequency outcomes and the quantity of any lost customer load due to UFLS. Where the model predicted load shedding, the value of this lost load was derived using a VCR of $42.52/kWh and an assumed outage duration of 1 hour.[130] The results of this modelling suggested that wider PFCB settings lead to more extreme frequency outcomes and increased volumes of UFLS. The expected cost of this load shedding in 2022 dollars is shown in Figure 6.2.

129 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.13.

130 Ibid.

Figure 6.2: Estimated cost of load shedding due to different PFCB settings for key non-credible contingencies ($m in 2022)



Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.46.

Note: Valuation assumes outage duration of 1-hour and Value of customer reliability of $42.52/kWh.

The GHD modelling estimates the additional cost of load shedding at between $6 million and $34 million depending on the specific operational scenario. The Panel notes that the nature and incidence of non-credible contingency events is inherently uncertain. As such these results are not interpreted as a definitive measure of the benefit of narrow band PFR, rather they provide a sense of the scale of value to electricity consumers for narrow settings of the PFCB.

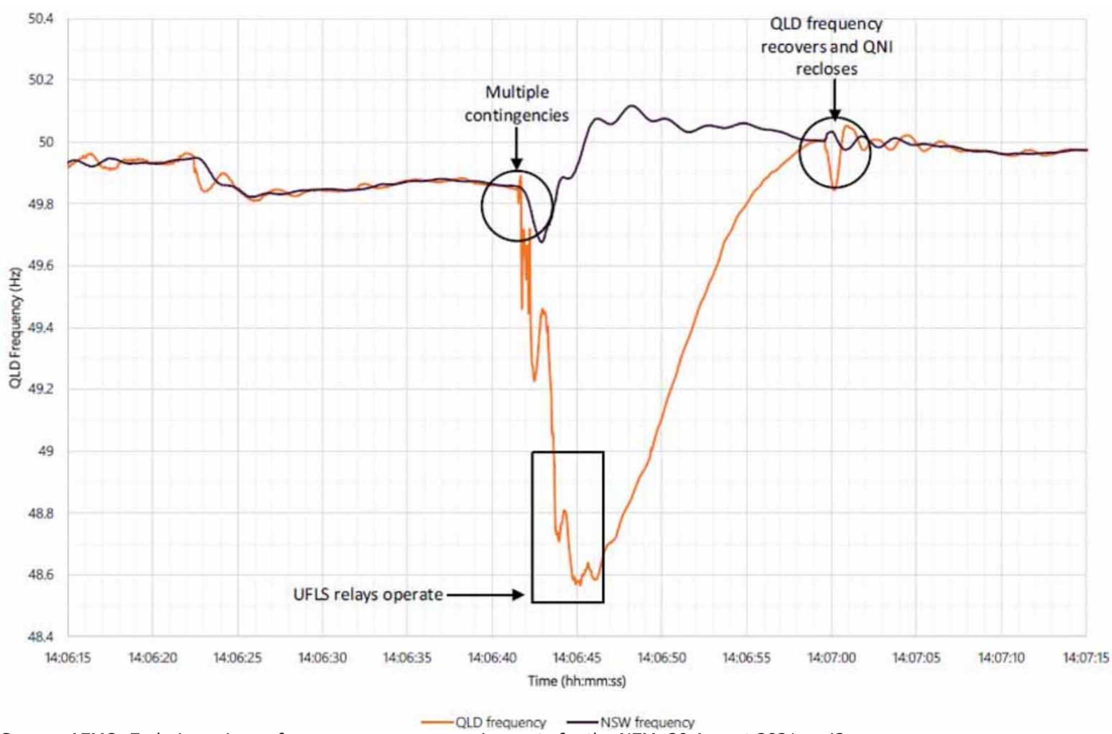
In the context of the uncertainty and operational challenges inherent to the ongoing power system transformation, the Panel notes that narrow band PFR provides additional resilience to unpredictable high impact low probability events. This is indicated in the GHD analysis to be likely to reduce the expected cost of UFLS following such events. While the total resilience benefits of tight frequency control around 50 Hz are difficult to quantify, it is likely that they extend beyond those set out in the GHD analysis to include - for example - decreased risk of other severe outcomes following non-credible contingencies such as regional separation and, at the extreme, black system events.

Narrow PFCB settings increase the likelihood of rapid re-synchronisation following separation events

Tight control of frequency around 50 Hz has been shown to deliver further resilience benefits through enabling the rapid re-synchronisation of islanded regions following non-credible separation events. This beneficial consequence of narrow band PFR is noted in AEMO's advice and supported by the results of power system modelling undertaken by GHD.

AEMO's advice notes that recent operational experience has shown that controlling frequency close to 50 Hz delivers improved resilience to non-credible separation events.[131] Distributed narrow band PFR is shown to increase the likelihood of rapid synchronisation of the islanded regions, thereby speeding up system recovery and reducing the impact of the event on electricity customers. The separation of Queensland and New South Wales due to multiple generation contingencies on 25 May 2021 provides an example of frequency outcomes following such an event. The frequency trace for NSW and QLD during this event is shown in Figure 6.3.

Figure 6.3: Queensland and New South Wales frequency profile during 25 May 2021 separation event



Source: AEMO, Enduring primary frequency response requirements for the NEM, 20 August 2021, p.42.
Note: Queensland frequency measured at Stanwell 275 kV substation Phasor Monitoring Unit.
Note: New South Wales frequency measured at Sydney West 330 kV substation Phasor Monitoring Unit.

Following this event AEMO noted that:[132]

> Tighter control of frequency as a result of widespread PFR in both Queensland and the rest of the NEM (as a result of the MPFR implementation) supported entirely automatic

131 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.14.
132 AEMO, Enduring primary frequency response requirements for the NEM, 20 August 2021, p.42.

> reconnection of these separated areas in around 15 seconds, as opposed to the minutes to hours it has taken for manual reconnection during previous Queensland separation events.

In recognition of the uncertainty associated with comparing historical power system events, the Panel arranged for the resynchronisation of separated power system regions to be investigated by GHD through power system modelling. This modelling approach can control scenario variables, such that a comparison based purely on different setting for the PFCB can be made. GHD's advice noted that:[133]

> Power system islands can only be re-synchronised when system voltages and frequencies at connection points are close enough to allow breakers to close without damage. This requires careful monitoring of the voltages and frequencies on each island to determine that conditions are right for re-synchronisation. The success criteria for these studies were chosen to be when power system island frequencies were within 0.01% of each other, equivalent to 2 mHz.

Controlling frequency close to 50 Hz provides separated regions with a common reference point that supports re-synchronisation. GHD's analysis demonstrates this through comparing the amount of time that the frequency of two separate regions meet the criteria for resynchronisation over a sample 6-hour period for a wide and narrow PFCB setting. The results of this study are shown in Table 6.1.

Table 6.1: Re-synchronisation of islanded regions

PFCB — DEADBAND	PERCENT OF TIME SUCCESS CRITERIA MET — 2022	PERCENT OF TIME SUCCESS CRITERIA MET — 2033
15 mHz	39.0%	45.4%
500 mHz (including Contingency FCAS at 150 mHz)	5.5%	4.1%

Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.43.

The results of the GHD analysis indicate that tight control of system frequency around 50 Hz — driven by a narrow setting for the PFCB — leads to a 7-fold increase in synchronisation criteria being met in the 2022 power system. This increases to an 11-fold increase for the 2033 power system.[134]

133 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.43.

134 Ibid.

Distributed control through narrow band PFR provides redundancy in the event of central control system failure

Narrow band PFR — through a narrow setting of the PFCB — delivers additional resilience by way of providing an additional layer of distributed control through the collective action of each of the individual units of responsive plant dispersed throughout the power system. AEMO's advice notes that this distributed narrow band PFR provides redundancy in the event of contingency and separation events, as described above, but also in the event of failure or mal-operation of AEMO's automatic generation control system which provides centralised control of generators in the NEM.

The power system events on 24 January 2021 provide an example of the benefit of this redundancy of controls. On this day, AEMO's Supervisory control and data acquisition (SCADA) system failed for a period of 1 hour and 10 minutes. As set out in AEMO's PFR Technical white paper:[135]

> During this period:
>
> - AEMO lost operational visibility of power system conditions and could not use SCADA for dispatch of generation or for centralised secondary frequency control.
> - AEMO's AGC was unable to ramp generation between market dispatch points, or control units enabled for Regulation FCAS.
> - Frequency remained within the requirements of the FOS throughout the incident, and did not depart the NOFB.

AEMO's analysis of power system behaviour during this event concluded that universal narrow band PFR provided by scheduled and semi-scheduled generators was instrumental in controlling system frequency during this period, despite the absence of central dispatch and regulation services. The responsive generation fleet provided an aggregate change in active power in response to system frequency that was able to maintain frequency within the NOFB. AEMO estimated that up to 1,157 MW of PFR was provided in the form of reduced generation — or frequency lower services — far beyond the volume of lower services enabled prior to the start of this event. AEMO noted that:[136]

> Widespread PFR was able to automatically act in a coordinated manner to provide supply-demand balancing and frequency control, as it responds to the universal property of system frequency, rather than relying on centralised communication and control processes via SCADA.

This example demonstrates how widespread narrow band PFR provides resilience benefits beyond the quantifiable impact on load-shedding as described in the GHD analysis on the resilience impacts of varying the PFCB.

135 AEMO, Enduring PFR requirements for the NEM - White Paper, August 2021, p.42.

136 Ibid.

6.2.3 A narrow setting for the PFCB delivers lower total costs for controlling system frequency

Consistent with stakeholder responses to the issues paper, a key focus of the Panel's consideration for this element of the FOS has been the analysis of the costs and benefits associated with different settings for the PFCB that directly relates to the expected range of power system frequency during normal operation. This analysis builds on the approach and methodology for pricing PFR, developed by the AEMC through the *Primary frequency response incentive arrangements* rule change.

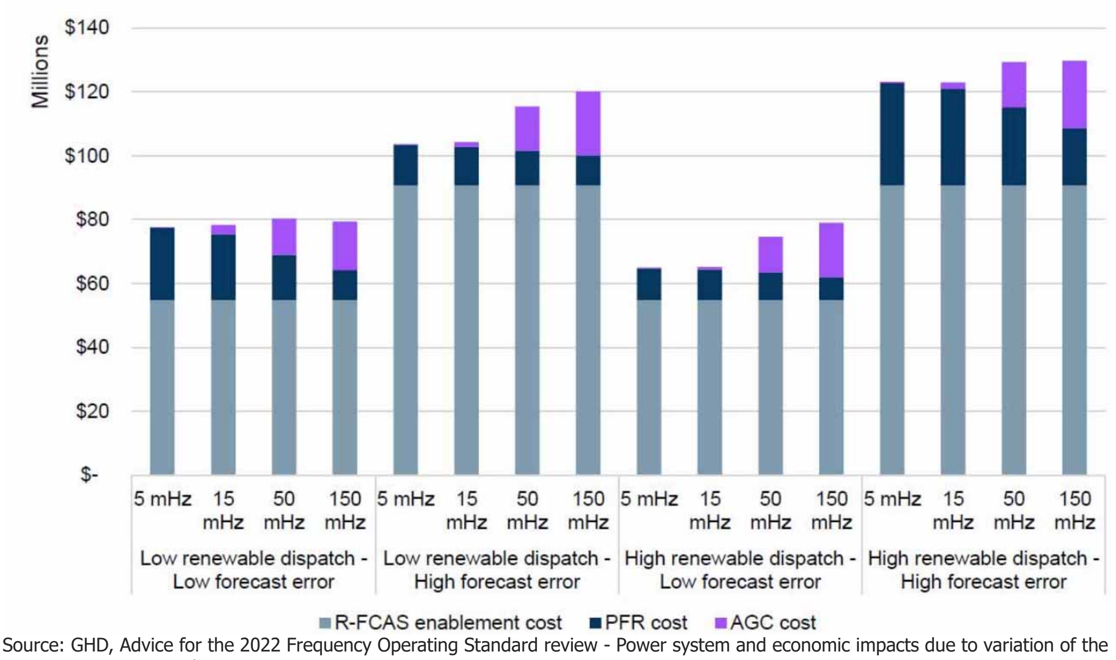
Further details on the underlying assumptions and modelling methodologies are available in section 4.2.3 of the draft determination.

Normal operation modelling results — cost impact of varying the PFCB

The GHD analysis predicts that narrower settings for the PFCB would deliver lower total costs for control of power system frequency. The expected reduction in costs for narrower PFCB settings accounts for the costs of both PFR and regulation FCAS which work together to control frequency during normal operation. While the modelling predicted reductions in cost and duty for PFR deviation due to wider PFCB settings, the value of these reductions was modest and it was more than offset by increased costs and duty associated with the provision of regulation services.

The high-level results for the 2022 dispatch cases are set out in Figure 6.4.

Figure 6.4: Aggregate frequency control costs for different PFCB settings — annualised



Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.iv.

The GHD analysis extended the investigation of operational costs relating to frequency control during normal operation to look at the behaviour of the generation fleet predicted in 2033 under the 2022 ISP step change scenario. While noting that the 2033 analysis was based on regulation FCAS prices for the 2021 sample period, the high level results for the normal operation study in 2033 were similar to the 2022 results, although the duty by technology reflected the increased proportion of inverter-connected plant and battery energy storage systems (BESS) expected in the system in 2033.[137] GHD noted that:[138]

> The analysis found that a reduction in PFR work caused by the widening of the PFCB, resulting in a decrease in PFR costs, was entirely offset by an increase in the requirement for R-FCAS providers to do work. Therefore, there was no compelling case to widen the deadband on this basis, as the system-wide costs marginally increased as the deadband was widened across a range of scenarios.

Stakeholders considered that the GHD advice did not account for material maintenance and operational costs from the 15 mHz deadband

Stakeholder submissions to the draft determination disputed GHD's findings that the current PFCB settings reduce the aggregate cost of managing power system frequency due to the lack of consideration of significant maintenance and operations costs borne by generators.[139] Origin's submission stated that:[140]

> Origin considers the relationship between the FOS settings during normal operation and the primary frequency control band (PFCB) should be further explored by the Panel. Specifically, a slightly wider PFCB of +/-30mHz may reduce the costs incurred by generators while still ensuring tight frequency control. In Origin's view, the potential costs / benefits of a more incremental widening of the PFCB to +/-30mHz, as explored in analysis provided by specialist consultancy Provecta, should also be considered.

This view is echoed by generators and the AEC, who commissioned the specialist consultancy Provecta to review the Panel's draft determination. The Provecta analysis proposed two options that may reduce ongoing maintenance costs:[141]

> It is suggested that widening the deadband to +/- 30MHz would eliminate much of the PFR reaction to [frequency oscillations in the NEM] while still providing tighter control over frequency than before MPFR was introduced.

An alternative could also be:[142]

> It is suggested that consideration should be given for a three-region PFR droop profile:

137 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.iv.

138 Ibid., p.v.

139 Submissions to the draft determination: SnowyHydro, p.2; AEC, p.2; CS Energy pp.4-5; Delta Electricity, p.4; Origin, p.1.

140 Origin, submission to the draft determination, pp1-2.

141 Provecta, Review of the NEM Frequency Operating Standard GHD consultancy report, 23 December 2022, p.2.

142 Ibid., p.3.

> 0-15mHz deadband; 15-30mHz 10% droop; over 30mHz 4% droop. These adjustments can be readily made in most DCS-based MW controllers and would reduce the impact on boiler-turbine processes while still providing support to hold frequency well within the NOFB.

The Panel considers that the proposal of varying the deadbands and droop settings for individual generators with technical limitations is consistent with the NER and the revised FOS. The Panel notes that the PFCB in the FOS sets the minimum deadband that AEMO can require of eligible generators through its *Primary frequency response requirements*. However, AEMO is authorised to agree on individual generator settings for deadband and droop through its implementation of the *Primary frequency response requirements*.[143] For example, the Panel notes that AEMO has agreed to generator specific settings for Crowlands WF, Moorabol WF, Poatine PS and Vales Point PS.[144]

6.3 The Panel will monitor system frequency performance during normal operation and recommends a follow up review of these settingsby no later than 2027

The Reliability Panel recognises there is a necessity for narrow band PFR to control frequency close to 50 Hz. Under the current arrangements, there is a reliance on mandatory PFR to deliver this narrow band control. The frequency performance payment arrangements which commence from 8 June 2025 are expected to provide an incentive for the provision of narrow band PFR beyond and in addition to the mandatory requirement.

The Panel recognises that it would be appropriate to review the settings in the FOS for normal operation, including the PFCB, again at a future date. This future review would be able to account for the rapid rate of change in the power system and also to review the economic and operational outcomes following on from the commencement of the new frequency performance payments arrangements.

Stakeholder submissions to the draft determination agreed that the Panel should reconsider the settings for normal operation as part of the next review of the FOS. TasNetworks, CS Energy and the CEC expressed support for the Panel's proposed timeline for the next review of the FOS to commence in 2027.[145] TasNetworks noted that it would:

> ...provide time to evaluate the impact of the recently introduced frequency performance payments.

Similarly, CS Energy concluded:

> The Panel has suggested that the settings for normal operation should be reviewed again in 2027. CS Energy agrees with this but also considers that the sunset clause for

143 Clause 4.4.2A(b)(i) of the NER.

144 AEMO, Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020 status report, 17 November 2022, pp.9-22.

145 Submissions to the draft determination: CEC, p.1; CS Energy, p.6; TasNetworks, p.1.

> mandatory PFR should be extended to allow for the performance of wider deadbands to be examined, and for all participants to have a better understanding and quantification of the impact on their units.

The Panel agrees that the proposed timeline will allow for a better understanding of the costs and benefits of wider deadbands in the NEM. However, the Panel also notes that the current mandatory PFR arrangements will already endure beyond 4 June 2023 as the *Primary frequency response incentive arrangements* rule change revoked the relevant sunset provisions.[146]

Several stakeholders considered that the proposed timeline is too far in the future.[147] The AEC concluded that:[148]

> The AEC considers it incorrect to lock in this tuning parameter for five years at this time.

While the Panel notes these views, we consider that it would best for a further review of the settings in the FOS for normal operation to be informed by operational experience with the new frequency performance payments arrangements in effect. The Panel considers that a subsequent review of the FOS should occur by no later than the end of 2027. The Panel recommends this timeframe, noting that a subsequent review could be commenced earlier if it was warranted. It also recognises that if it was to occur in 2027, that timing would allow for a period of almost 12 - 18 months to monitor the impacts of the frequency performance payments arrangements and inform further consideration of the PFCB and the settings in the FOS for normal operation. Further commentary on this follow up review for the FOS is included in section 1.3.3.

In the meantime the Panel will continue to monitor frequency performance and related developments through its *Annual market performance review*. In particular, the Panel intends to monitor and report on frequency performance during normal operation and the interaction with aggregate frequency responsiveness.

146 AEMC, Primary frequency response incentive arrangements, Rule determination, 8 September 2022, p.1.

147 Submissions to the draft determination: Shell Energy, p.5; Delta Electricity, p.4; AEC, p.2.

148 AEC, submission to the draft determination, p.2.

7 THE REVISED FOS REMOVES THE LIMIT ON ACCUMULATED TIME ERROR

BOX 7: KEY POINTS IN THIS SECTION

Time error is a measure of the accumulated time the power system has spent away from the nominal frequency target of 50 Hz.

- Currently, the FOS requires AEMO to maintain accumulated time error on the mainland and Tasmania to less than 15 seconds except during islanded operation or during supply scarcity for the mainland or a multiple contingency event in Tasmania.
- The revised FOS removes the quantified limit on accumulated time error while retaining the requirement for this metric to be monitored and reported on. Therefore, there is no longer a requirement on how much accumulated time error may or may not exist. However, the Panel considers it is important that there still be transparency and knowledge about how much accumulated time errors exists.
- This change to the FOS:
    - would improve the efficient operation of the power system by reducing the costs of ancillary services borne by market consumers
    - would be unlikely to have any detrimental impacts on consumers or any negative system security outcomes were time error allowed to accumulate.
- Stakeholders were generally supportive of removing the limit on accumulated time error. At the same time stakeholders supported the retention of the requirement for AEMO to report on time error as a valuable frequency performance metric.

Time error is a measure of the accumulated time the power system has spent above or below exactly 50 Hz. If the real power system frequency is persistently above or below 50 Hz, even by a small amount, then the actual flow of energy in the system may differ slightly from that assumed through the energy market. Over time such variations, left unchecked, can accumulate thereby shifting resulting in a misalignment between synchronous and real time.[149]

The final determination for stage 1 of the 2019 review of the FOS relaxed the limit on accumulated time error in the mainland to 15 seconds, thereby harmonising the limit with the existing requirements in Tasmania.[150] At the time, the Panel also concluded that there may have been a case for the complete removal of the limit, taking into account any potential unforeseen impacts on large and small customers, once further consultation had been undertaken.

149 Refer to section 7.1 of the issues paper for further explanation of time error.

150 Reliability Panel, Review of the frequency operating standard - stage one determination, 14 November 2016.

The revised FOS — consistent with the draft determination — removes the quantitative limit on accumulated time error while the requirement for monitoring and reporting on time error is maintained through the NER. Under clause 4.8.16 (a)(1)(iii) of the NER, AEMO is required to report on a comparison of power system frequency performance against the time error requirements specified in the FOS as part of its weekly frequency performance report. In its quarterly report, AEMO must report on its assessment of the achievement of the frequency operating standard in accordance with clause 4.8.16 (b)(2). The revised FOS maintains accumulated time error as a component of the FOS, but clarifies that there is no effective limit that must be met. Therefore, AEMO will continue to be required to monitor and report on time error on a weekly and quarterly basis, consistent with clause 4.8.16 of the NER.

The requirement to monitor and report on time error will provide value to stakeholders as measure of system frequency performance, while the FOS will not set any hard limits on the allowable range for accumulated time error. This would provide AEMO with more flexibility in relation to how it manages time error and will allow system changes over time to support reductions in associated costs due to time error correction.

All stakeholder submissions to the draft determination that referenced the change to settings for accumulated time error supported the Panel's decision.[151]

This section outlines the Panel's reasoning for removing the limit in the FOS for accumulated time error, including:

- Section 7.1 — time error is a valuable frequency performance metric
- Section 7.2 — time error has minimal impacts on consumers and the power system
- Section 7.3 — relaxing the limit on time error will allow for reduced FCAS costs.

Additional details on the Panel's considerations with respect to the limit on accumulated time error are available in Chapter 5 of the *draft determination*.

In determining these revised arrangements, the Panel has aimed to improve the efficient operation of the power system, in line with consumer preferences, by allowing for the costs of ancillary services to reduce while maintaining the existing reporting obligations to provide transparency for market participants.

7.1 Time error is a valuable frequency performance metric

The Panel recognises that time error is a valuable metric for monitoring and reporting on frequency performance in the power system. This view is supported by most submissions to the issues paper.[152] As such, while the revised FOS removes the requirement for time error to be maintained below a set value, the existing level of monitoring and reporting that stakeholders have grown accustomed to would be maintained.

AEMO has provided expert advice to this review on the limit for accumulated time error in the FOS. It advised that there were no clear benefits to system security or consumers from time

151 Submissions to the draft paper: AEC, p.4; CEC, p.1; CS Energy, p.7; Delta Energy, p.1.

152 Submissions to the issues paper: AEC, p.5; Energy Australia, p.4; TasNetworks, p.6; Iberdrola, p.6; Shell Energy, p.5; Origin Energy, p.2.

error correction. However, the inclusion of a standard in the FOS does enable AEMO to monitor and report on developments, thereby providing stakeholders with a valuable source of transparency. As such, AEMO's advice to the Panel concluded that:[153]

> While removing the time error standard entirely would be unlikely to lead to any direct issues, the standard nonetheless [provides] transparency to the market and consumers [in] ensuring that the total energy delivered into the grid aligns with expectations.

The Panel notes that the revised FOS maintains the requirement for AEMO to monitor and report on time error accumulation.[154] This requirement was broadly supported by stakeholder submissions to the issues paper and draft determination and will retain the same level of transparency currently available to market participants.[155] It will also allow active monitoring for any unforeseen consequences from this change that might exist.

7.2 Time error has minimal impacts on consumers and the power system

The Panel considers it important that any change to the accumulated time error settings in the revised FOS not result in a deterioration of security outcomes nor place an undue burden on market participants or AEMO. In revising the settings for time error, the Panel considers the effect it would have on customers that potentially still rely on synchronous time to not be significant.

7.2.1 Time error has immaterial impacts on electricity consumers

The materiality of the accumulation of time error on residential, commercial or industrial consumers has been considered by the Panel as part of this review. The Panel considered whether the costs incurred to correct for time error would be balanced by the potential benefits from retaining the synchronicity between real and system time. Otherwise, maintaining the standard would not be in the long term interests of consumers.

The Panel concluded that removing the obligation for AEMO limit time error to a specific value is unlikely to negatively affect market participants or consumers. This position is consistent with the previous review of the FOS which raised the possibility of abolishing the requirement altogether following further consultation.[156]

GHD's survey of system operators and regulators supported the Panel's hypothesis that it is unlikely that removing the requirement in the FOS would have an adverse effect on consumers. [157]

153 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.61.

154 Under clause 4.8.16(b)(2) of the NER, AEMO will continue to prepare and publish quarterly reports on the achievement of the FOS including rate of time error accumulation in the NEM and Tasmania.

155 Submissions to the draft determination: CEC, p.1; CS Energy, p.7; AEC, p.4.

156 Reliability Panel, Review of the Frequency Operating Standard - Stage one, Final Determination, 14 November 2016, p.51.

157 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.iii.

Submissions to the issues paper and draft determination expressed doubts about the consumer benefits from time error correction.[158] [159] The AEC, TasNetworks and Energy Australia noted that the periodic resetting of time error by AEMO without any discernible impact implies that removing the requirement on AEMO would have an immaterial impact.

7.2.2 Removing the limit on accumulated time error is unlikely to affect system security

AEMO's advice on the appropriateness of the current settings on accumulated time error concluded that there were no system security or reliability benefits from continuing time error correction. AEMO noted in its advice that:[160]

> AEMO's advice is that the Reliability Panel consider removing a time error limit from the FOS, recognising AEMO will still monitor and control time error as necessary.

Similarly, the findings from GHD's jurisdictional survey further reinforced the Panel's position that the removal of obligations to correct for time error would have an immaterial effect on security and consumers.[161]

7.3 Relaxing the limit on time error will allow for reduced FCAS costs

To correct the accumulation of time error, AEMO applies a small frequency offset to run the power system marginally above (or below) the nominal frequency of 50 Hz for a period of time. This process is referred to as time error correction and leverages the AGC system by controlling units enabled to provide regulation FCAS.

The Panel's previous review of the FOS considered the value of maintaining synchronicity with real-time given the replacement of synchronous clocks by modern alternatives. AEMO's advice to the 2019 FOS review estimated the costs incurred, over the timespan between January 2016 to June 2017, to be on the order of $1 million per annum in increased regulation FCAS costs.

AEMO's advice to this review of the FOS has applied a different calculation methodology thereby resulting in increased estimated costs.[162] As such AEMO noted that:

> Estimated costs for FY2022 of approximately $1.9 million per annum are lower than estimated costs for FY2017 of approximately $2.8 million per annum.

It is important to note that the introduction of mandatory PFR and the considerable increase in base regulation FCAS volumes applied could have influenced the calculation of the estimated cost of time error correction. AEMO believes that the recent improvements in frequency performance have resulted in reduced correction costs.

158 Submissions to the issues paper: AEC, p.5; Energy Australia, p.4; TasNetworks, p.6; Iberdrola, p.6; Shell Energy, p.5; Origin Energy, p.2.

159 AEC, submission to the draft determination, p.4.

160 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, pp.60-61.

161 GHD, System rate of change of frequency — A GHD survey of international views, 18 November 2022, p.33.

162 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.56.

ABBREVIATIONS

AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic generation control system
BESS	Battery energy storage systems
Commission	See AEMC
DC	Direct current
DNSP	Distribution network service provider
EFCS	Emergency frequency control scheme
FCAS	Frequency control ancillary service
FFR	Fast frequency response
FOS	Frequency operating standard
Hz	Hertz
IBR	Inverter-based resources
ISP	Integrated system plan
MASS	Market ancillary service specification
MPFR	Mandatory primary frequency response
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NER	National Electricity Rules
NOFB	Normal operating frequency band (49.85 – 50.15 Hz)
NOFEB	Normal operating frequency excursion band (49.75 – 50.25 Hz)
NSP	Network service provider
OFTB	Operational frequency tolerance band
PFCB	Primary frequency control band
PFR	Primary frequency response
PFRR	Primary frequency response requirements
RoCoF	Rate of change of frequency
SCADA	Supervisory control and data acquisition
SWIS	South West Interconnected System
TNSP	Transmission network service provider
UFLS	Under frequency load shedding scheme
WEM	Wholesale Electricity Market

A CONSULTATION AND DEVELOPMENT PROCESS

A.1 The AEMC provided terms of reference to the Panel about this review

On 28 April 2022, the AEMC provided Terms of Reference to the Panel to initiate a review of the FOS (the Review). These can be found on the project page for the review on the AEMC website.[163]

Among other things, the Terms of Reference require the Panel to consider:

- Whether the terminology, standards, settings and definitions in the FOS remain appropriate.
- The settings in the FOS that apply for normal operation, including:
  - The normal operating frequency band (NOFB)
  - The normal operating frequency excursion band (NOFEB)
  - The requirement that:

    Except as a result of a contingency event or a load event, system frequency:

    a) shall be maintained within the applicable normal operating frequency excursion band, and

    b) shall not be outside of the applicable normal operating frequency band for more than 5 minutes on any occasion and not for more than 1% of the time over any 30 day period.

- The Primary frequency control band referred to in clause 4.4.2A of the NER.
- The settings in the FOS for credible and non-credible contingency events.
- What amendments to the FOS may be necessary and appropriate to support the implementation of market arrangements for fast frequency response (FFR). This may include the specification of system operating standards for the rate of change of frequency (RoCoF) and other settings as appropriate.

The Panel is required to complete its review by 7 April 2023. This will allow for a period of at least 6 months from the date the revised FOS is determined to the date that the new market ancillary service arrangements for FFR commence on 9 October 2023.

The Commission also requested that the final report include the Panel's recommendation on the timing for the next review of the FOS.

163 Refer to: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

A.2 The Panel received technical advice from AEMO and GHD to support its review

The NER requires that the Panel's determination of the FOS be made "on the advice of AEMO".[164] Therefore, in addition to consulting with key stakeholders and the engagement of independent advice, the Panel received advice from AEMO to support its review and determination of the FOS. The Panel has published a copy of AEMO's advice as a companion to its draft determination.[165]

To complement AEMO's advice, the AEMC also engaged GHD to provide independent technical and economic advice to inform the Panel's Review of the FOS. The Panel published a copy of GHD's advice as a companion to its draft determination.[166]

A.3 Consultation process

In carrying out this review, the Panel is following a consultation process consistent with clause 8.8.3 of the NER and the Terms of Reference. The Panel has consulted with stakeholders through seeking submissions to the issues paper and this draft determination. The Panel also held two public forums and carried out meetings with interested stakeholders on request. Key dates for the review are shown in Table A.1.

Table A.1: **Timetable for the review**

MILESTONE	DATE
Publish issues paper and terms of reference	28 April 2022
Public forum	27 May 2022
Close of submissions to the issues paper	9 June 2022
Receive AEMO advice	December 2022
Publish draft determination	8 December 2022
Publish final determination	6 April 2023
Implementation date for the revised FOS	9 October 2023

A.3.1 Issues paper

The Panel published an issues paper on 28 April 2022 to initiate this review of the FOS. The paper set out the issues for consideration relating to the FOS for stakeholder comment. It was the first of a series of opportunities that stakeholders had in providing input on the Panel's determination. There were four key issues that the Panel outlined in the paper to which it asked for stakeholder consultation:

- the settings in the FOS for normal operation

164 Clause 8.8.1(a)(2) of the NER.

165 Refer to: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022

166 Ibid.

- the potential inclusion of a system standard for RoCoF
- the settings in the FOS for contingency events
- the limit on accumulated time error.

Submissions to the issues paper were due by 9 June 2022. The Panel received 11 stakeholder submissions in total. The Panel took account of stakeholder comments in making its draft determination.

A.3.2 Draft determination

The Panel published a draft determination on 8 December 2022. The draft determination outlined the proposed changes by the Panel and allowed stakeholders to provide feedback on the draft FOS. The key changes to the FOS that the Panel made in the draft determination were:

- the introduction of system limits for post-contingency RoCoF
- the settings in the FOS for contingency events
- the settings in the FOS for normal operation
- the removal of the limit on accumulated time error.

Submissions to the draft determination were due by 2 February 2023. The Panel received 9 stakeholder submissions in total. The Panel has taken into account stakeholder comments in making its final determination.

B BACKGROUND AND CONTEXT

The appendices of the issues paper and Appendix B of the draft determination summarise background information relevant to this review.[167]

The appendices of the issues paper outline:

- Appendix A — elements of the FOS
- Appendix B — provides descriptions of power system frequency, frequency control, and contingency events
- Appendix C — overview of the NEM's frequency control frameworks, including AEMO's responsibility for maintaining the secure operation of the power system, the role of FCAS and EFCS, and how the FOS relates to the generator and network technical performance standards.

The appendices of the draft determination outline:

- Appendix A — the consultation and development process of the review of the FOS
- Appendix B — background and context, including the FOS in the NEM, frequency performance in the NEM and related work programs. Including:
  - AEMO's *Engineering Framework*[168]
  - AEMO's review of the MASS — FFR specification[169]
  - The AEMC's assessment of the *Primary frequency response incentives arrangements* rule change[170]
  - The AEMC's assessment of the *Operational security mechanism* rule change[171]
  - The AEMC's assessment of the *Efficient provision of inertia* rule change.[172]

167 Refer to: https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022
168 AEMO, Engineering Framework - Initial Roadmap, December 2021, pp.26-27.
169 AEMO, Amendment of the Market Ancillary Service Specification (MASS) – Very Fast FCAS, October 2022
170 Refer to: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements
171 Refer to: https://www.aemc.gov.au/rule-changes/operational-security-mechanism
172 Refer to: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia