RULE

Australian Energy Market Commission

CONSULTATION PAPER

PRIMARY FREQUENCY RESPONSE RULE CHANGES

PROPONENTS

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INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

EXECUTIVE SUMMARY

The control of power system frequency in the National Electricity Market (NEM) has been deteriorating in recent times. The gradual shift toward more variable sources of electricity generation and consumption, and difficulties in predicting this variability, increases the potential for imbalances between supply and demand that can cause frequency disturbances. At the same time, generators who are not enabled to provide frequency control through the ancillary service markets have been decreasing or removing their responsiveness to correct frequency deviations on a voluntary basis. Declining frequency performance of the power system contributes to inefficient operation of generators and market outcomes and reduces the resilience of the power system to contingency events.

Generators can help to control system frequency by automatically changing power output in response to locally detected variations in frequency. The Australian Energy Market Commission (AEMC or Commission) has received three rule change requests that relate to the arrangements in the National Electricity Rules (NER) for the provision of frequency response from generators. Two of these rule change requests were submitted by the Australian Energy Market Operator (AEMO) and one rule change request was submitted by Dr Peter Sokolowski. These rule change requests propose a number of changes to the regulatory arrangements governing the control of power system frequency. Chief amongst these changes are proposals to mandate that all capable scheduled and semi-scheduled generators be operated such that they are responsive to changes in the locally measured power system frequency, and to address the perceived dis-incentives that currently exist in the NER which have contributed to generators becoming less responsive to frequency changes over time.

Each of these rule change requests builds on previous work undertaken by AEMO and the AEMC. In particular, the AEMC's *Frequency control frameworks review*, which concluded in July 2018, and AEMO's incident report into the Queensland and South Australia system separation event on 25 August 2018, have both provided an important foundation for understanding and assessing the issues.

The final report of the AEMC's *Frequency control frameworks review* highlighted several issues with the existing market and regulatory arrangements for frequency control, and made recommendations on how they could be addressed. The final report included a collaborative frequency control work plan that set out a series of actions that would be progressed by the AEMC, AEMO and the AER to address issues related to frequency control in the NEM over the short, medium and long term. AEMO's rule change requests are related to this work plan.

Improving power system security as a priority

AEMO recognises that the proposal to mandate frequency response from generators represents a significant change to the frequency control arrangements that have been in place in the NEM since 2001. Under the current arrangements, frequency response is only required by those market participants that are enabled to provide frequency control ancillary services (FCAS) through the related ancillary service markets. However, AEMO considers that the decline in frequency performance has reached a point where there is now an immediate need for additional frequency response to restore effective frequency control in the NEM to maintain the safety, security and reliability of the power system. AEMO has therefore requested that this rule change request be progressed in the shortest reasonable time frame, balancing the requirement for appropriate consultation with the potential consequences of the ongoing lack of effective frequency control under normal operating conditions.

The Commission acknowledges the immediate need to improve frequency performance in the power system and sees the three rule change requests as an opportunity to improve power system security, which the AEMC has identified as one of the five key priority areas for reform in the NEM. In determining a solution, the Commission will seek to address system security first and foremost. While the Commission acknowledges the need to optimise economic efficiency of service delivery, this needs to be balanced against the implications of an insecure power system.

When the fundamental system security needs are met, the Commission will seek to investigate further improvements to the frequency control arrangements to increase the overall economic efficiency of frequency control in the NEM. The Commission intends to develop a reform pathway that will allow for this evolution to minimise the overall costs to the market of providing PFR. This approach is consistent with the frequency control work plan that was agreed as part of the *Frequency control frameworks review* in which the Commission recommended the development of a mechanism to incentivise the provision of a sufficient quantity of PFR over the long term to support good frequency performance during normal operation.

Time frames

This consultation paper has been published to facilitate consultation on the three rule change requests from AEMO and Dr Sokolowski. Submissions in response to this consultation paper should be provided to the AEMC by 31 October 2019. Following receipt of stakeholder submissions to this consultation paper, the Commission will work to publish a draft rule and draft determination that addresses the immediate system security need in the earliest reasonable time frame, as requested by AEMO in it rule change request, *Mandatory primary frequency response*. The Commission will aim for a draft determination to be published by December 2019 and will invite stakeholder feedback on this draft determination prior to the publication of a final rule and rule determination in Q1 2020.

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

The Australian Energy Market Commission (AEMC or Commission) has recently received three rule change requests that relate to the arrangements in the National Electricity Rules (NER) for the provision of primary frequency response (PFR) to help control power system frequency in the National Electricity Market (NEM).

AEMO defines PFR as:[1]

> the response of generating systems and loads to arrest and correct locally detected changes in frequency by changing their active power output or consumption. PFR is automatic; it is not initiated by an external, centralised control system and [it] begins immediately after a frequency change beyond a specified level is detected by the responsive plant.

Furthermore, AEMO states that:[2]

> PFR is essential for power system security. Accurate knowledge of available PFR is required for power system modelling and event analysis, and is critical following power system disturbances and during power system restoration.

Each of these rule change requests builds on previous work undertaken by AEMO and the AEMC. In particular, the AEMC's *Frequency control frameworks review*, which concluded in July 2018 and AEMO's *Final report - Queensland and South Australian system separation on 25 August 2018,* which provided an important foundation for understanding and assessing the issues. Stakeholders are encouraged to refer to these reports for further background on the issues discussed in this consultation paper.

This consultation paper has been prepared to facilitate public consultation on the rule change requests and to guide stakeholder submissions in relation to the issues raised and the solutions proposed by the rule change proponents.

1.1 Overview of the rule change requests

The three rule change requests relating to PFR are:

- ERC0274 — Mandatory primary frequency response
- ERC0263 — Removal of disincentives to primary frequency response during normal operation
- ERC0277 — Primary frequency response requirement

Each of these rule changes is discussed briefly below.

1 AEMO, 1 July 2019, Removal of disincentives to the provision of primary frequency response under normal operating conditions — Electricity rule change proposal, p.4.

2 Ibid.

1.1.1 ERC0274 — Mandatory primary frequency response

On 16 August 2019, AEMO submitted a rule change request to the AEMC seeking a change to the NER to require all capable scheduled and semi-scheduled generating units to provide PFR once frequency moves outside a defined frequency band. AEMO proposes that it prepare a new specification document setting out the technical details for PFR. AEMO proposes that the PFR technical specification, *Primary frequency response requirements (PFRR)*, includes the specification of the frequency response band. AEMO's draft setting for this frequency response band in the PFRR is ±0.015Hz from 50Hz.

AEMO's rule change request is supported by written advice from John Undrill, who is an international expert in power system operation and frequency control. The advice from John Undrill is summarised in section 2.5.

AEMO's rule change request states that:[3]

- AEMO is increasingly unable to control frequency in the NEM under normal operating conditions, due to reduced provision of PFR from generation.
- The tools currently available to AEMO cannot effectively control frequency on an ongoing basis, and are increasingly resulting in power system outcomes that AEMO now regards as inconsistent with prudent industry practice.

AEMO's proposed rule is seeking to:[4]

- Re-establish effective control of power system frequency, and thereby align the NEM with standard international practice.
- Increase the resilience of the power system to disturbances, particularly events beyond simple N-1 credible contingency events.
- Ensure a predictable frequency response from generation to power system disturbances, to support power system planning and modelling.

Urgency of the proposed rule

AEMO recognises that the proposed rule represents a significant change to the frequency control arrangements that have been in place in the NEM since 2001. However, AEMO considers that there is an urgent need to restore effective frequency control in the NEM to maintain the safety, security and reliability of the power system. AEMO has therefore requested that this rule change request be progressed:[5]

> in the shortest reasonable time frame, balancing the requirement for appropriate consultation with the potential consequences of the ongoing lack of effective frequency control in normal operating conditions.

3 AEMO, Mandatory Primary frequency response — Electricity rule change proposal, 16 August 2019, p.4

4 Ibid, p.28.

5 AEMO, *Mandatory primary frequency response* — Rule change request, 16 August 2019, p.41.

The Commission's proposed time frame for the assessment of the PFR rule changes is described in section 1.6.

The Commission's priorities and assessment framework for the rule change process are discussed in chapter 5.

1.1.2 ERC0263 — Removal of disincentives to the provision of PFR

On 3 July 2019, AEMO submitted a rule change request to the AEMC seeking changes to the NER to address perceived disincentives to the voluntary provision of PFR by participants in the NEM. Through consultation with market participants, AEMO has identified the following aspects of the NER as being perceived to provide disincentives to the voluntary provision of PFR:

- Certain aspects of the arrangements for the allocation of costs associated with regulation services, known as 'causer pays'.
- A focus by generators on prioritising strict compliance with dispatch instructions over operating their plant in a frequency response mode and providing PFR.
- A perception that the NER requires generators to provide PFR only when they are enabled to provide a Frequency control ancillary service (FCAS).

AEMO's proposed rule seeks to address these perceived disincentives in the NER to remove barriers to the provision of voluntary PFR during normal operation and halt the decline of frequency performance during normal operation.

1.1.3 ERC0277 — Primary frequency response requirement

On 30 May 2019, Dr Peter Sokolowski submitted a rule change request to the AEMC seeking changes to the NER to improve the control of frequency within the NEM. Dr Sokolowski is a research fellow in the school of electrical and biomedical engineering at RMIT University. He submitted this rule change as a private individual.

Dr Sokolowski's rule change request states that the deterioration of frequency control in the NEM is undermining the predictable dynamic response of the system and leading to a range of issues that negatively impact the safety, reliability, security and quality of the power system and the price for the supply of electricity.

Dr Sokolowski's proposed rule seeks to improve the security of the power system through the following changes to the NER:

- clarification that, in addition to maintaining system security, AEMO is responsible for improving system security, consistent with the National Electricity Law (NEL)
- including a mandatory requirement for registered generators in the NEM to provide PFR outside of a deadband no greater than ±0.025Hz either side of 50Hz.
- including changes to remove disincentives to the provision of PFR and clarify that a generator shall control its power output not only in accordance with its dispatch instructions but also subject to local frequency

- including changes to the clauses relating to inertia and inertia support services to accommodate new technologies that help control frequency, such as fast frequency response from inverter connected plant.

1.2 Purpose of this consultation paper

This consultation paper has been prepared to facilitate public consultation on the rule change requests and to seek stakeholder submissions.

This paper:

- sets out the background for the issues related to frequency control in the NEM
- provides a summary of the issues raised in the rule change requests and the proponents proposed solutions
- identifies a number of questions and issues to facilitate the consultation on these rule change requests
- outlines the Commission's assessment framework and priorities
- describes the process for stakeholders to provide submissions to the consultation process.

We welcome submissions on this consultation paper.

We also welcome interested stakeholders to contact us if they would like to meet with us to discuss this consultation paper or any related issues.

All enquiries in relation to the PFR rule change request should be directed to Ben Hiron on (02) 8296 7843 or ben.hiron@aemc.gov.au.

1.3 The Frequency control frameworks review

In July 2018, the AEMC concluded its *Frequency control frameworks review.* The review investigated the current market and regulatory frameworks that underpin frequency control in the NEM in light of the opportunities and challenges presented by rapid technological change in the electricity industry. The final report highlighted several issues with the existing market and regulatory arrangements for frequency control, and made recommendations on how they could be addressed.

The final report included a collaborative frequency control work plan that set out a series of actions that would be progressed by the AEMC, AEMO and the AER to address issues related to frequency control in the NEM over the short, medium and long term. The status of actions related to the frequency control work plan is published on the AEMC website. [6] AEMO's rule change requests are related to the Frequency control work plan. In particular, the action that AEMO:[7]

> communicates whether there is a need to implement interim measures before a longer-term mechanism for primary frequency control within the normal operating

6 See: https://www.aemc.gov.au/our-work/our-forward-looking-work-program/system-security/frequency-control-work-plan

7 AEMC, 26 July 2018, *Frequency control frameworks review - Final report*, p.62.

> frequency band comes into effect.

and

> continues its work on assessing the longer-term needs of the power system, based on a holistic view of inertia, primary and secondary frequency control

The three rule change requests, from AEMO and Dr Sokolowski, raise a range of issues, which also relate to the joint AEMC and AEMO action to:

> assess how the longer-term approach is best implemented with respect to the other anticipated changes in frequency control needs of the power system.

Therefore, the AEMC intends to use the assessment of these rule change requests to address any immediate power system needs related to system security in the short term and, depending on this outcome, may also investigate the potential benefits of additional measures to improve the economic efficiency of frequency control in the NEM over the longer term.

1.4 Queensland and South Australia system separation on 25 August 2018

On 25 August 2018, lightning struck transmission lines that form the QNI inter-connector between the Queensland and New South Wales regions. Shortly afterwards unstable power flows led to the disconnection of the Heywood inter-connector between South Australia and Victoria. Following the event, the power system separated into three islanded regions consisting of:

- the QLD region
- the interconnected VIC-NSW region and Tasmania via Basslink
- the SA region

The event resulted in the interruption of 997 MW of electricity supply to industrial loads in VIC, NSW, and Tasmania, and some residential and commercial customers in NSW.

AEMO published a report detailing its findings from an investigation of this operating incident. In the report, AEMO identified two key factors that increased the reliance on load interruption to rebalance power system demand with supply on 25 August 2018:[8]

1. Limited or no primary frequency control response from many generators - noting there is no regulatory obligation and no commercial incentive to provide frequency control other than through existing FCAS markets.
2. The distribution of FCAS reserves across the NEM at the time of the event - the allocation of contingency and regulation FCAS reserves does not usually include any need for geographic distribution. In this event there were significant

8 AEMO, Final Report – Queensland and South Australia system separation on 25 August 2018, 10 January 2019, p.6.

> differences between the needs of the power system, and the distribution of frequency response enabled via FCAS markets.

Historically, generation PFR beyond the procured FCAS reserves could broadly be relied on to minimise the probability of such load interruption. AEMO's analysis of this event demonstrated this is no longer the case.

AEMO's investigation of the 25 August event illustrated the extent of the decline in power system frequency performance, and the need for immediate measures to arrest it. AEMO made several recommendations to address this decline in frequency performance, including principal recommendations for:[9]

> a) AEMO to work with the AEMC, AER and NEM participants to establish appropriate interim arrangements, through rule changes as required, to increase primary frequency control (PFC) responses at both existing and new (synchronous and non-synchronous) NEM generator connection points where feasible, by Q3 2019.
>
> b) AEMO to support work on a permanent mechanism to secure adequate PFC as contemplated in the AEMC's *Frequency Control Frameworks Review*, with the aim of identifying any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.

1.5 Process for consultation on the rule change requests

The Commission is initiating consultation on the three rule change requests at the same time. At this stage, the rule change requests will not be consolidated. Assessing each rule change request separately will allow for solutions to be assessed and implemented on a timeline that reflects the priority of the issues they relate to.

1.5.1 AEMO's request for a non-controversial rule change for removal of disincentives to PFR

AEMO has requested that its rule change request, *Removal of disincentives to primary frequency response*, be assessed via the expedited process under the NEL. Section 96 of the NEL allows for the AEMC to assess rule change requests via an expedited, eight week time-frame if they meet the test for being either an urgent rule or a non-controversial rule. AEMO proposes that the Removal of disincentives to PFR rule change request be assessed as a non-controversial rule as it is not likely to have a significant impact on the NEM.

A non-controversial rule is defined in the NEL as:[10]

> a Rule that is unlikely to have a significant effect on the national electricity market.

The national electricity market also includes the national electricity system.

9 Ibid. p.8.

10 NEL Section 96

If the AEMC considers that a request for a rule is a request for a non-controversial rule, it may choose to assess that rule via an expedited process. Under the expedited process, the NEL provides for an eight-week time frame between the initiation of the rule change process and the publication of the final rule determination. The expedited time frame allows for one opportunity for formal stakeholder consultation on the rule change request.

AEMO's request for a non-controversial rule

AEMO has requested that the rule change request be assessed as a non-controversial rule on the basis that the proposed rule:

- clarifies the intent of the NER.
- does not directly result in (or require) changes in Generator behaviour. Rather, any effect is due to Generators deciding to change the frequency responsiveness of generating plant in response to financial incentives.
- is not likely to add any new costs to the power system, but may result in a reallocation of regulation FCAS costs among market participants. The extent of any reallocation is limited by the cost of regulation FCAS which in 2018 was $62 million, equivalent to 0.4% of the overall value of energy traded in the NEM in FY 2017-2018.[11]

The Commission's view on AEMO's request for a non-controversial rule

The Commission has considered the arguments put forward by AEMO in its rule change request, but has determined to assess the rule change request in accordance with the standard time frames under the NEL.

The Commission does not consider that the rule change request meets the requirements for a non-controversial rule on the basis that the proposed rule will have an impact on the power system, through a reallocation of costs associated with regulation FCAS among market participants. The Commission considers that the goal of the proposed rule is to remove disincentives to the provision of PFR and as a result, for market participants to choose to operate their plant in a way that is responsive to changes in system frequency. Market participants who become frequency responsive will be rewarded with a reduced allocation of regulation FCAS costs while non-responsive market participants can expect an increased allocation.

In the context of these expected impacts, the Commission considers that it is appropriate to consider the issues raised in the rule change request through the standard rule change process. Further commentary on non-controversial rules is included for reference in appendix c.

The key dates associated with the consultation on the proposed rule are included below in section 1.6.

11 AEMO, 1 July 2019, Electricity Rule change proposal, Removal of disincentives to the provision of primary frequency response under normal operating conditions.

1.6 Timetable for the consultation process

The Commission invites stakeholders to make submissions on this consultation paper by 31 October 2019.

Following receipt of stakeholder submissions to this consultation paper, the Commission will work to publish a draft rule and draft determination that addresses the immediate system security need in the earliest reasonable time frame.

The Commission aim to publish a draft determination that addresses the immediate security issues by December 2019 followed by a final rule determination in Q1 2020.

The Commission will provide updates to the expected timetable for the PFR rule changes via the respective project pages on the AEMC website.

2 BACKGROUND

Frequency performance under normal operating conditions has been deteriorating in recent times, primarily as a result of generators decreasing or removing their responsiveness to minor frequency deviations. Declining frequency performance of the power system contributes to inefficient operation of generators and market outcomes and reduces the resilience of the power system to contingency events.

The provision of primary frequency response (PFR) has many benefits for frequency control, both during normal system operation and following contingency events. Increasing the provision of PFR across the NEM could materially improve frequency control and reduce reliance on load shedding to preserve the power system during large frequency disturbances.

This chapter provides background on power system frequency control which is relevant to consideration of the three rule change requests relating to the provision of PFR, and includes the following sections:

- Section 2.1 — An overview of AEMO's tools to control frequency and the role of PFR
- Section 2.2 — The recent degradation of frequency performance in the NEM
- Section 2.3 — The drivers of frequency performance degradation in the NEM
- Section 2.4 — How PFR is approached in power systems outside the NEM
- Section 2.5 — Technical advice for AEMO on frequency control and PFR in the NEM
- Section 2.6 — Related AEMO and AEMC work programs
- Section 2.7 — Inertia and inertia support activities

An overview of frequency control fundamentals is included in Appendix A.

2.1 Frequency control and PFR

BOX 1: WHAT IS PRIMARY FREQUENCY RESPONSE?

Primary frequency response (PFR) provides the initial response to frequency disturbances caused by power supply-demand imbalances. It reacts automatically and almost instantaneously to locally measured changes in system frequency outside predetermined set points. PFR involves an automatic change in active power generated (or consumed) by a generator (or load) in response to a locally measured change in system frequency.

In order to provide PFR, a generator must operate its plant in a 'frequency response mode' which is defined in chapter 10 of the Rules as: "the mode of operation of a generating unit which allows automatic changes to the generated power when the frequency of the power system changes."

As noted by AEMO in its *Mandatory primary frequency response* rule change request, the key attributes of PFR are that it is:

- **Locally responding** — responds to locally measured frequency and, hence, is not subject to centralised control, communications delays and time synchronisation issues.
- **Fast acting** — provides an immediate action to respond to frequency deviations.
- **Automatic** — responds automatically to adjust generation output to arrest and stabilise frequency, typically in proportion to measured frequency deviation outside predetermined set points.

PFR is a distinctly different service from secondary frequency response. PFR provides fast control action that responds rapidly to contain frequency deviations, while secondary frequency response is a slower control action that acts to relieve PFR providers and to help rebalance energy supply and demand until generation dispatch can be adjusted.

Historically in the NEM, only synchronous generating systems have provided PFR. However, asynchronous generators such as wind, batteries and solar PV, can also provide PFR. As these technologies form an increasingly large proportion of the supply mix, it is important that any PFR arrangements consider the capabilities and performance of these newer technologies adequately.

PFR can be provided by:

- the variation of generator output by 'governor systems' that regulate the output of generating units
- the variation of active power supplied to or consumed from the power system by inverter-based generation and loads.

Under current arrangements, PFR is provided by fast and slow contingency FCAS services that operate outside the normal operating frequency band (NOFB). The NOFB is defined in the frequency operating standard as 49.85 Hz - 50.15 Hz.[12] PFR may also be voluntarily provided by generator governor response and active power control within the NOFB. Providers of PFR within the NOFB are not directly paid for being frequency responsive. However, they are likely to receive a reduced share of the costs of regulation FCAS through AEMO's causer pays procedure.[13]

PFR is required for effective frequency control, in coordination with inertia and secondary frequency control services, for both normal system operation and following contingency events.

12 AEMC Reliability Panel, Frequency operating standard, 14 November 2017.

13 AEMO's causer pays procedure is the mechanism by which regulation services costs are allocated to Market Generators and Loads on the basis of their contribution factors calculated over a period of a month. These factors reflect the degree to which the generators actual output or, in the case of a scheduled load, their actual demand, differ from the targets assigned by the NEM dispatch engine (NEMDE).

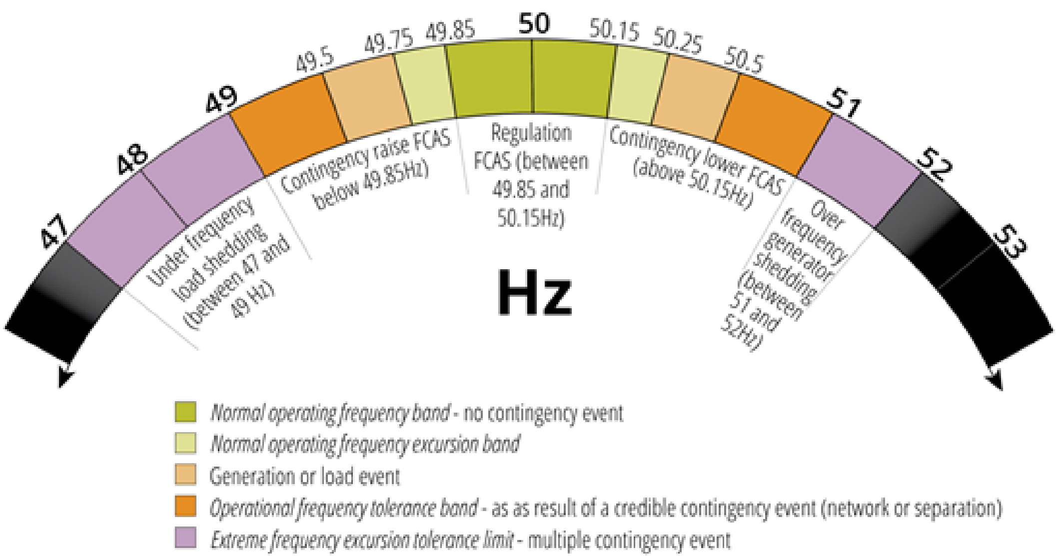
2.1.1 Overview of AEMO's tools for managing frequency

AEMO is responsible under the NER for maintaining power system security. One aspect of this is that AEMO must use its reasonable endeavours to control power system frequency.[14] AEMO controls frequency during normal operation and manages the impact of contingency events through a coordinated use of the following four mechanisms:

- generator technical performance standards (GTPS),
- regulation frequency control ancillary services (FCAS) markets
- contingency frequency control ancillary services (FCAS) markets,
- emergency frequency control schemes (EFCS),
- the protected event framework,
- the reclassification of contingency events.

Together, these tools provide AEMO a breadth of methods to address contingency events that may occur in the NEM. The range of tools and the associated frequency bands for which they apply in the mainland NEM are shown below in Figure 2.1.

Figure 2.1: Frequency control tools and active frequency bands



Source: AEMC

Generator Technical Performance Standards

Generator technical performance standards are mandatory performance standards required of each and every generator connected to the NEM as part of their connection agreements.

14 Clause 4.4.1(a) of the NER.

These standards include standards in relation to frequency control which are set out in S5.2.5.11 of the NER.

The automatic access standard that applies to generator frequency control states that a generating system must not increase power output in response to a rise in frequency or decrease power output in response to a decrease in frequency.[15] Furthermore, the standard requires that the generating system has the capability to operate in a frequency responsive mode such that it responds to a rise in frequency by proportionally decreasing power output and responds to a decrease in frequency by proportionally increasing power output.

The minimum access standard that applies to generator frequency control requires that, in response to change in system frequency, a generator’s output must not worsen an over frequency situation. The minimum access standard also places limits on the degree to which a generator's output may decrease in response to a fall in system frequency. While this standard also requires generators to be capable of operating in a frequency response mode similar to that above, it is a mode where frequency response may not be proportional to the frequency deviation and can be subject to energy availability of the generating system.

All generators connected on or after 5 October 2018 have a negotiated access agreement meeting requirements at or between these two standards.[16]

Regulation FCAS Markets

Under clause 3.11.2 of the NER, AEMO enables capacity reserves for the provision of regulation services on a five-minute basis through the NEM spot market. The regulating services respond to electronic signals sent by AEMO’s automatic generation control system (AGC) and provide a secondary frequency response to help rebalance supply and demand and correct frequency deviations within the NOFB during normal system operation.

The regulation services include a raise and a lower service that respond to AGC signals to help increase or decrease the power system frequency respectively. Regulation services are designed to respond to relatively slow changes in the supply demand balance of energy. The effective response of these services occurs over a time frame of 10-30 seconds.

The performance characteristics for the contingency services are set out in AEMO’s Market Ancillary Service Specification (MASS).

This is the only tool AEMO has under the NER to procure frequency control services that operate within the NOFB.

Contingency FCAS Markets

Clause 3.11.2 also sets out six additional ancillary services as reserve capacity to help rebalance supply and demand following credible contingency events. As with the regulating services, AEMO procures contingency FCAS on a five-minute basis through the NEM spot market. The contingency service markets include the fast, slow and delayed lower services

15 NER Clause S5.2.4.11

16 Generators connected prior to this date will have similar or equivalent standards.

which help to correct frequency excursions above 50.15Hz and the fast, slow and delayed raise services to correct frequency excursions below 49.85Hz.

Generators (or loads) that are enabled to provide contingency FCAS respond automatically to deviations in the power system frequency beyond a prescribed frequency setting.

As with regulating services, the performance characteristics for the contingency services are set out in AEMO's MASS.

The fast and slow contingency FCAS markets are AEMO's current tools for procuring PFR and correcting frequency excursions outside the NOFB. AEMO only procures volumes of contingency FCAS appropriate to respond to the largest single contingency event it believes to be reasonably possible at a given time.

Emergency Frequency Control Schemes (EFCS)

EFCS are automatic control schemes that act to disconnect generation (over frequency generation shedding, OFGS) or load (under frequency load shedding, UFLS) to help rebalance the power system following non-credible contingency events. EFCS are triggered as a last resort option to arrest large frequency deviations before the frequency moves outside of the extreme frequency excursion tolerance limits. The NER requires that up to 60% of load within a region shall be available for UFLS to help protect against a cascading outage leading to a major supply disruption and potentially a black system.

Protected Event Framework

Under the NER, AEMO may make an application for a specific non-credible contingency to be declared a protected event. The Reliability Panel is responsible for assessing the costs and benefits of managing the event as a protected event and determining if the event is to be declared a protected event.

For a protected event, AEMO may procure frequency control ancillary services (FCAS) or constrain network flows or generator dispatch, in addition to load or generation shedding, to maintain the frequency operating standards applicable to protected events.

Reclassification of contingency events

The NER requires AEMO to develop criteria for the reclassification of non-credible contingency events, given abnormal conditions, which the NER defines as including, without limitation: severe weather events, lightning, storms, and bush fires. If AEMO determines that the occurrence of the non-credible event is reasonably possible, based on the established criteria, then AEMO must reclassify the event as credible.[17] This enables AEMO to take pre-emptive measures such as FCAS procurement for events that are only possible under certain, measurable circumstances.

2.1.2 Role of PFR during normal system operation

Normal operating conditions refer to operation of the power system in the absence of any contingency event — that is, with all generators and network elements operating as expected

17 NER clause 4.2.3A(g).

with no unplanned outages. Minor imbalances between supply and demand regularly occur during normal operation resulting in continuous small frequency variations. The following events contribute to variation of frequency during normal operation:

- errors in the five-minute demand forecasts that are used in the dispatch process
- errors in the five-minute forecasts of variable intermittent generation, such as wind or solar, that are used in the dispatch process
- generating systems not following their dispatch targets
- smaller generating systems or loads partially changing their output or consumption, or tripping altogether.

The extent of the imbalance between available generation and load caused by these events is usually relatively small, at least compared to the kinds of imbalances expected for a larger contingency such as the tripping of a large generating system or load. Accordingly, the size of the subsequent frequency change is also relatively small.

During normal operation, frequency is controlled through a combination of PFR and secondary frequency control. Secondary frequency control is coordinated by AEMO through the procurement of regulating services which respond to electronic signals from AEMO's centralised automatic generation control system (AGC).[18] The NER do not include a mechanism to require or enable the provision of PFR during normal operation. Therefore, PFR during normal operation is largely provided voluntarily by generating plant operated in a frequency response mode that is sensitive to frequency within the NOFB.

AEMO's advice to the *Frequency control frameworks review* demonstrated how primary frequency response and secondary frequency response are fundamentally different and not interchangeable, and that both are vital to the effective management of frequency.[19] In particular, PFR provides fast control action that responds rapidly to contain frequency deviations, while secondary frequency response is a slower control action that acts to relieve PFR providers and to help rebalance energy supply and demand until generation dispatch can be adjusted. Beyond the time frames of primary and secondary frequency response, the balance between supply and demand is maintained via the NEM dispatch engine.

AEMO's advice stated that the total amount of PFR provided to the power system determines how far frequency will deviate for a given MW mismatch in supply and demand. In the absence of other changes to the system operating characteristics, increasing the level of active PFR acts to decrease the variation of power system frequency.

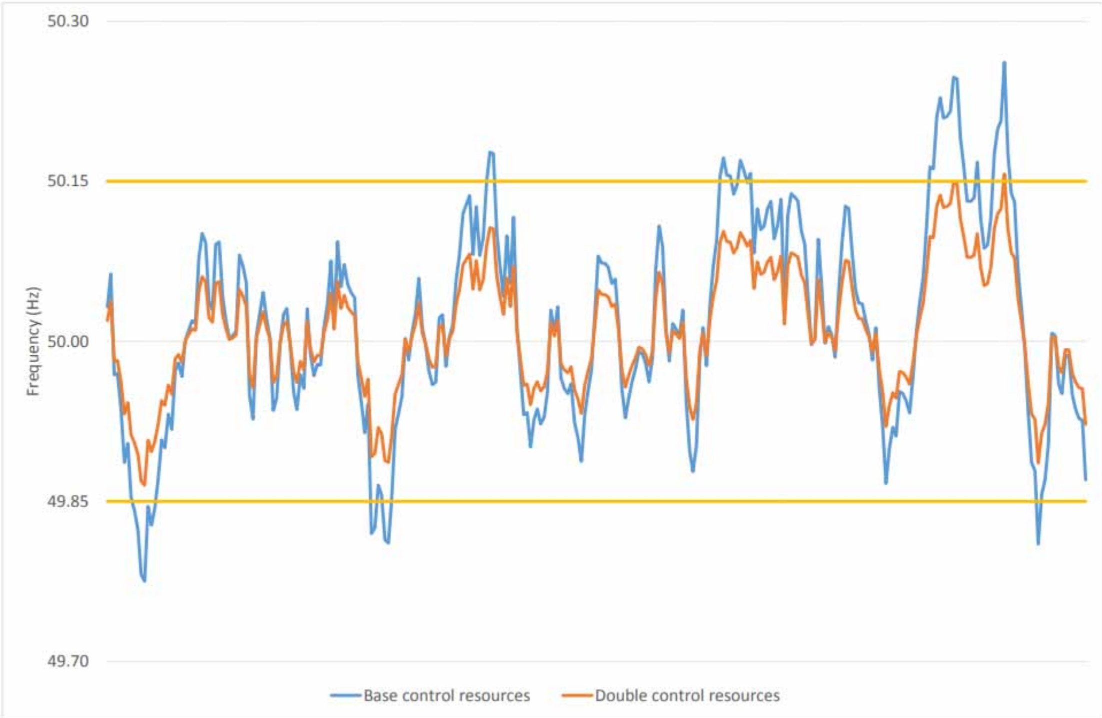
To demonstrate the impact of additional primary frequency control on the management of frequency variation AEMO constructed a simplified power system model. The model assumes continuous proportional primary response to frequency variation with no deadband and ignores the handover between primary and secondary response. Figure 2.2 shows that a doubling of primary response reduces the size of the frequency deviation within this hypothetical system by about 40 per cent. The chart includes an indicative representation of

18 Regulation FCAS is a form of secondary frequency response.

19 AEMO, Response to request for advice — Frequency control frameworks review, 5 March 2018, pp. 6-9.

the limits of a NOFB at 49.85Hz and 50.15Hz and shows how the reduction in frequency deviation drives a significant improvement in containing the frequency within the target range.[20]

Figure 2.2: Effect of PFR on frequency fluctuations within the NOFB



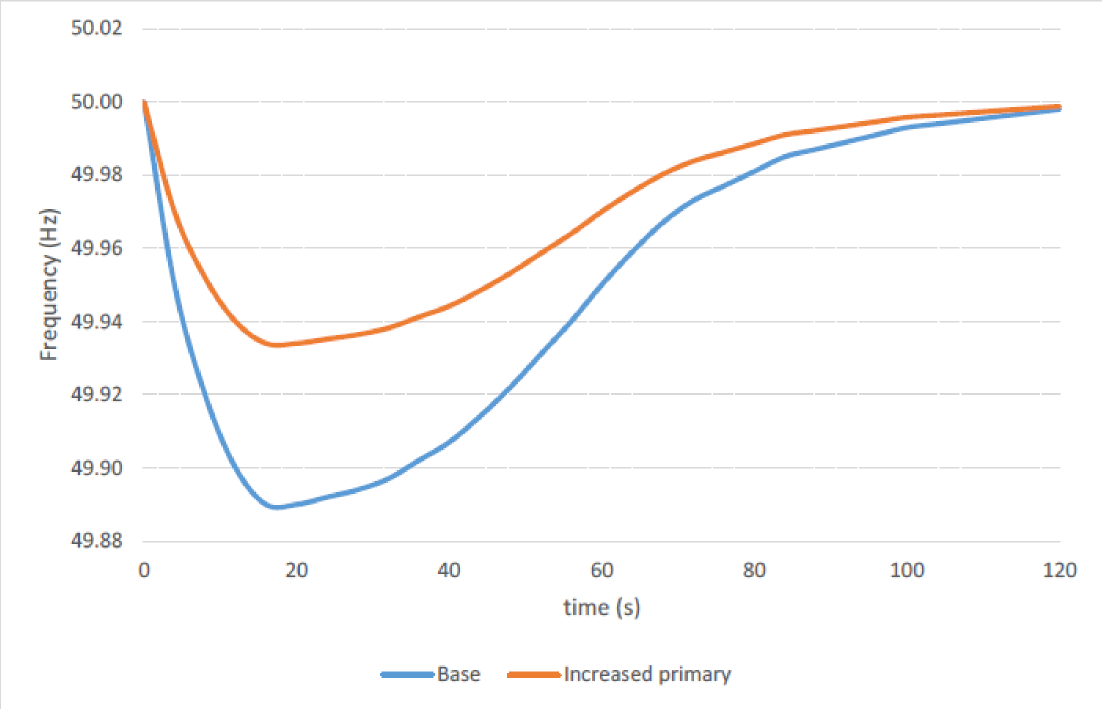
Source: AEMO, Response to request for advice — *Frequency control frameworks review*, 5 March 2018, pp.8-9.

Although PFR limits the size of a frequency deviation, the total time required to restore the frequency to the initial state will likely not change substantially with changes in PFR volumes. Similarly, AEMO's advice showed that an increase in secondary frequency response volumes without an increase in PFR may decrease the time required to rectify the imbalance but will not affect the magnitude of frequency deviation the imbalance causes.[21] Figure 2.3 and Figure 2.4 capture how PFR and secondary frequency response impact a frequency deviation.

20 AEMO, Response to request for advice — *Frequency control frameworks review*, 5 March 2018, pp.8-9.

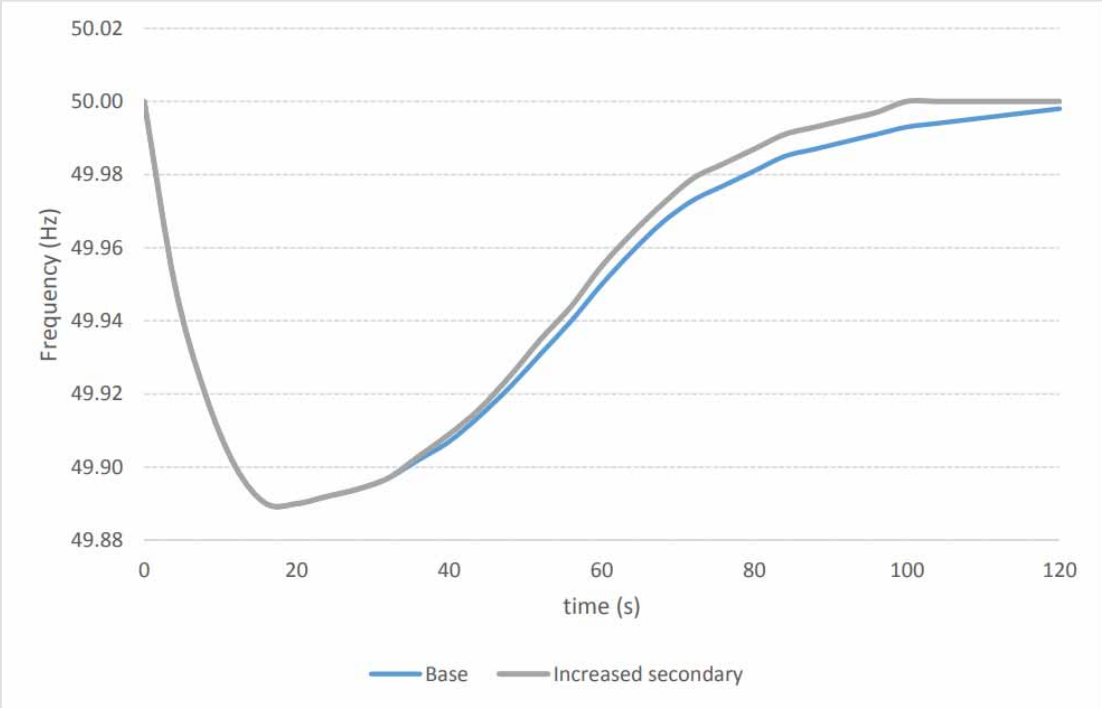
21 Ibid, pp.11-12.

Figure 2.3: Impact of PFR on a frequency deviation



Source: AEMO, Response to request for advice — *Frequency control frameworks review*, 5 March 2018, pp.11.

Figure 2.4: Impact of secondary frequency response on a frequency deviation



Source: AEMO, Response to request for advice — *Frequency control frameworks review*, 5 March 2018, pp.12.

AEMO considers that, assuming there is adequate secondary control to cover any underlying supply-demand mismatch, additional PFR will be more effective than additional secondary control to contain the maximum frequency deviation within a given frequency band and to reduce the integral frequency error over time (i.e. the area under the curve). [22]

AEMO's submission to the draft report for the AEMC *Frequency control frameworks review* noted that adequate provision of adequate PFR during normal operation requires that a significant proportion of the generation fleet is enabled at all times for the continuous provision of that service. AEMO's modelling suggests that greater than approximately 30% of the online fleet should be actively providing PFR at any given point in time for an effective primary response characteristic.[23] AEMO explained that the reason such high proportion of responsiveness is required is to keep the active power changes for each individual generating unit to a small fraction of the unit output. This allows for continuous and sustained response from generating units and reduces individual plant costs. [24]

22 Ibid.

23 Plant operating in a frequency responsive mode will not always deliver effective response due to reasons such as fuelling issues, available headroom, plant issues, and control points.

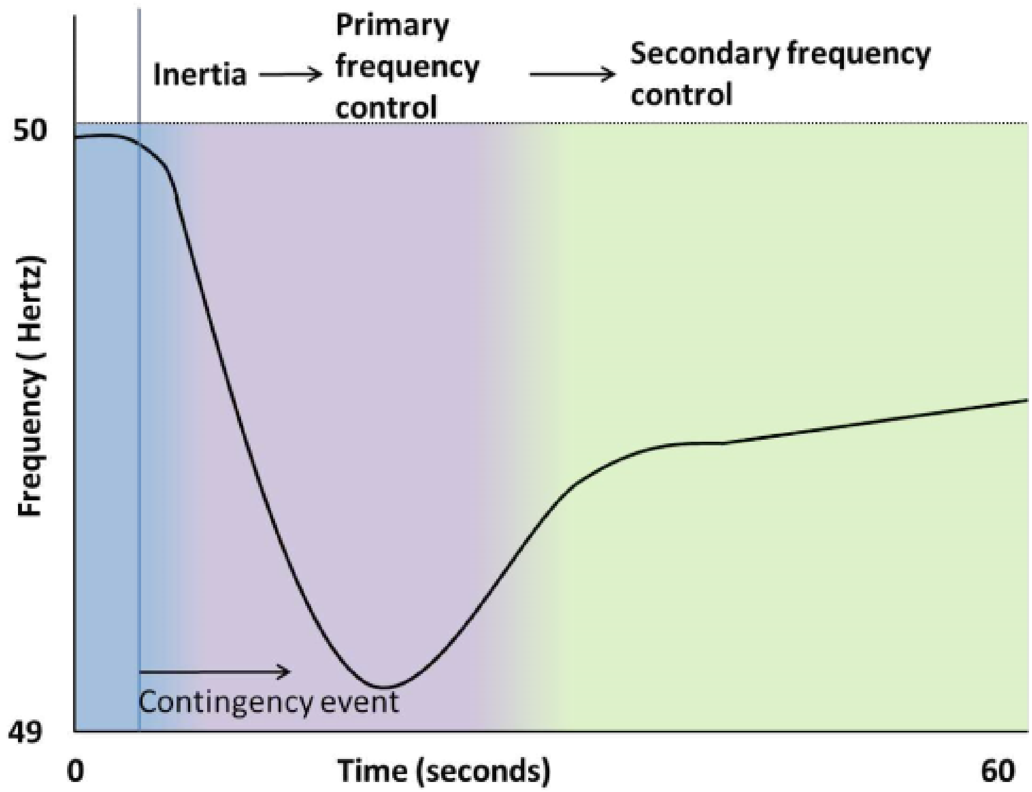
24 AEMO, Submission to the draft report for the Frequency control frameworks review, 26 April 2018, pp.7-8.

2.1.3 Role of PFR following contingency events

Following contingency events, such as the sudden unexpected disconnection of a major generating unit, PFR provides the initial response to frequency disturbances. It reacts almost instantaneously to changes in system frequency outside predetermined set points. In the NEM, PFR is currently only required to be provided by providers of contingency FCAS, which is procured by AEMO to cover the largest single credible contingency event that may occur in the power system.

Figure 2.5 below demonstrates how PFR interacts with inertia and secondary frequency control services following a contingency event.

Figure 2.5: Interaction between inertia, and primary and secondary frequency control



Source: AEMC

The initial rate of change of system frequency following a contingency event is determined by the system inertia. More inertia in the power system means a slower initial decline of power system frequency. However, inertia is not able to stabilise or restore the power system frequency on its own.

Following a contingency event, PFR, including that provided by fast and slow FCAS or voluntary response, acts to arrest the change in frequency. The amount of PFR determines the lowest point the frequency reaches, called the 'nadir'. As the PFR is typically proportional to the frequency deviation it is not able to fully restore the frequency to the pre-contingency state. Instead, this is achieved through the provision of secondary frequency response services. Secondary frequency response is provided by delayed and regulating FCAS and responds slower following a contingency event. It takes over from PFR in order to let responsive generating plant return to their normal set-points (and thus be ready for further PFR as required). PFR is essential in arresting frequency deviations and providing time for secondary services to react and restore the power system following a frequency disturbance. A more detailed description of the characteristics of primary and secondary frequency control is included in the AEMO advice for the *Frequency control frameworks review*.[25]

The nature of contingency events is that they are sudden, unexpected and generally instantaneous. Although these events are rare, some can have high impacts on the system and threaten system operation, sometimes triggering UFLS to prevent the event from causing system collapse. AEMO must manage system frequency disturbances and frequency recovery times to meet the Frequency Operating Standard (FOS).

Under the frequency operating standard, AEMO must ensure that, following a credible contingency event, the frequency deviation remains within the operational frequency tolerance band (OFTB), 49.0 – 51.0 Hz. AEMO achieves this through the procurement of contingency capacity reserves through the markets for contingency FCAS.

Under the current frameworks in the NER, AEMO procures enough contingency FCAS to control the frequency in accordance with the frequency operating standard for any single credible contingency event.[26] AEMO is not required to procure contingency FCAS to rebalance supply and demand following contingency events in excess of the largest credible contingency. For these non-credible contingency events the FOS allows for the frequency to exceed the operational frequency tolerance band and supply and demand are rebalanced through the operation of emergency frequency control schemes, including over-frequency generation shedding schemes and under-frequency load shedding schemes.

PFR provided voluntarily by market participants or in response to obligations related to enablement via the FCAS markets, contributes to the capability of the power system to deal with unexpected disruptions and avoid uncontrolled, cascading outage. This restoration capability is called power system 'resilience' and is discussed further in section 2.6.2.

2.2 Recent degradation of frequency performance in the NEM

Frequency performance in the NEM has been declining over the past few years. This degradation of frequency performance has been observed in a widening of the distribution of frequency during normal operation, an increased incidence of oscillations in the power system frequency and a decrease in the resilience of the power system to non-credible contingency events.

25 AEMO, Response to request for advice - *Frequency control frameworks review*, 5 March 2018, pp.8-9.

26 Following on from a review of its assumptions around the scale of load relief in the NEM, AEMO has commenced a progressive process that will result in an increase in the amount of contingency FCAS volumes it procures. AEMO, *Changes to Contingency FCAS volumes*, August 2019.

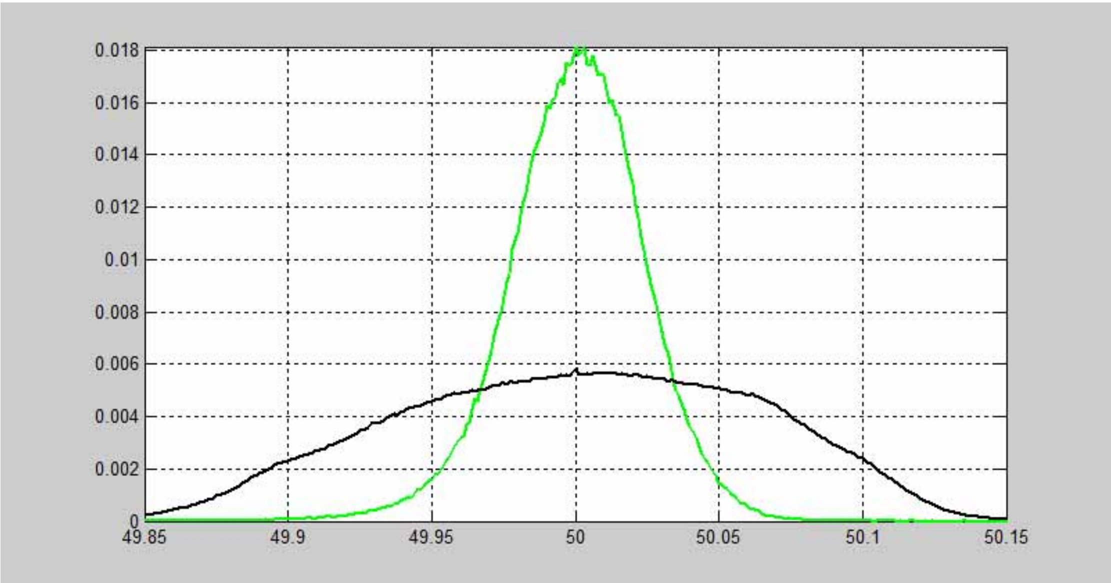
- Section 2.2.1 describes the degradation of frequency performance during normal operation
- Section 2.2.2 describes the degradation of frequency response following non-credible contingency events that are larger than a credible contingency event
- Section 2.2.3 describes the increased incidence of frequency oscillatory events

The drivers for the degradation of frequency performance in the NEM, including the reduction in the provision of PFR, are discussed in section 2.3.

2.2.1 Frequency performance during normal operation

Frequency performance under normal operating conditions has been deteriorating in recent times, evidenced by a flattening of the distribution of frequency within the NOFB. The mainland and Tasmania power system frequency is increasingly further away from 50 Hz than has historically been the case, as shown by the frequency distribution graph for 2018 as compared to 2005 in Figure 2.6.

Figure 2.6: Frequency distribution within the normal frequency operating band in the NEM 2005 snapshot v. 2018 snapshot



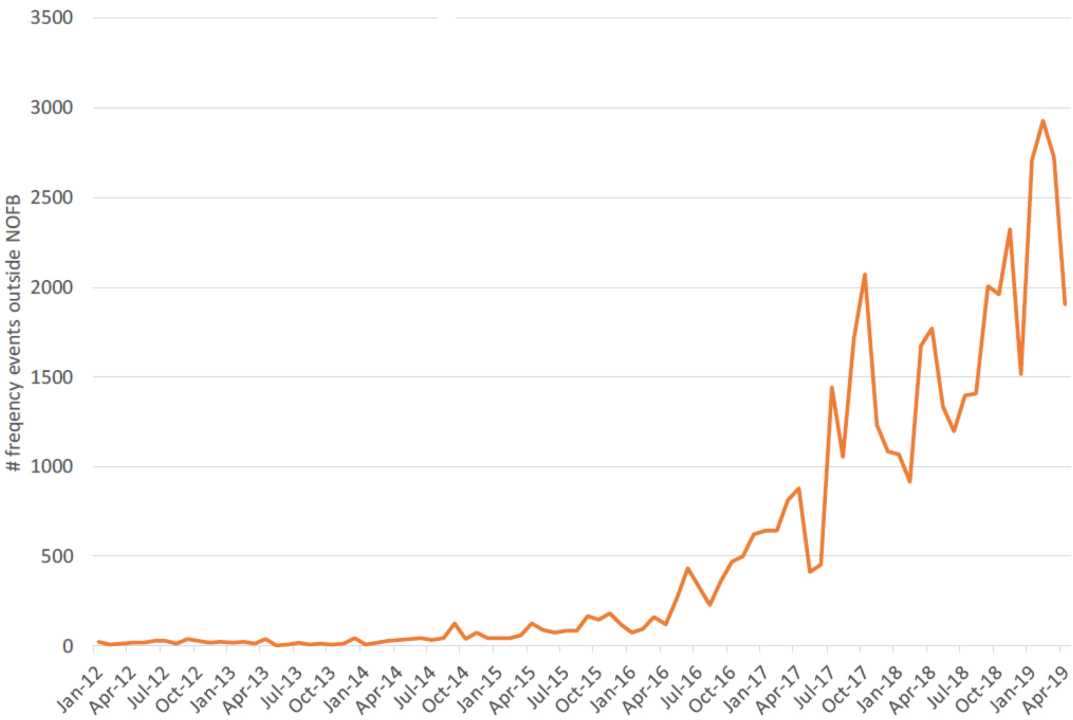
Source: AEMO, Removal of disincentives to the provision of primary frequency response during normal operating conditions — Electricity rule change proposal, 1 July 2019, p.14.

Note: X-axis: Frequency (Hz)

Note: green line shows 2005 data, blackline shows 2018 data.

AEMO has also reported an increased incidence of exceedance events, where the power system frequency falls outside the NOFB, as shown in Figure 2.7.[27] Many of these excursions have occurred under normal operating conditions in the absence of a contingency event.

Figure 2.7: Frequency excursions outside the normal operating frequency band



Source: AEMO

There are risks and costs associated with the power system operating more often at frequencies at the edges of the NOFB. The *Frequency control frameworks review* determined some of the consequences of deteriorating frequency performance to include:

- increased wear and tear on plant due to excessive movement caused by frequency deviations
- reduction in the efficiency of generators due to changes in output as result of deteriorating frequency regulation and governor response
- reduction in system security for contingencies that result in significant changes in transfer across inter-connectors
- potential need for additional contingency FCAS to maintain the same level of system security given increased variability of system frequency

27 The frequency operating standard requires that, in the absence of contingency events, the power system frequency is maintained within the normal operating frequency band (49.85 Hz to 50.15 Hz) for 99% of the time. The frequency may exceed the normal operating frequency band for 1% of the time, but , in the absence of a contingency event, it must not exceed the normal operating frequency excursion band, 49.75 – 50.25Hz.

- increase in regulating FCAS costs
- possibility of further withdrawal of PFR due to the added burden on existing PFR.

In its rule change request, AEMO also highlights that high variability in system frequency makes it more difficult for it to meet the Frequency Operating Standard and impedes its ability to model and predict power system behaviour. This, in turn, reduces AEMO's ability to consistently maintain the system in a secure operating state, such that it will recover following a credible contingency event or a protected event.

A discussion of the issues raised by AEMO and Dr Sokolowski in relation to the impacts of degraded frequency control is included in chapter 3.

2.2.2 Frequency response following contingency events

During the AEMC *Frequency control frameworks review*, AEMO considered that "time was still available for further investigations to understand [frequency performance] issues" and to address them through the actions included in the AEMC and AEMO *Frequency control work plan.* However, AEMO's analysis of system behaviour in the 25 August 2018 separation event demonstrated that the reduction in the provision of PFR by the generation fleet has increased the chance of under-frequency load shedding and over-frequency generation shedding following non-credible contingency events. AEMO now considers frequency response following non-credible contingency events to be a critical issue.[28]

> The events of 25 August 2018 demonstrate that the decline in PFR has already reached a point where the power system is not as resilient to contingency events of a magnitude only around 15% greater than the largest credible contingency event. [...] it is AEMO's view that an urgent response is now required.

AEMO considers that the current tools for managing frequency following contingency events are not sufficient and that there is an immediate need for additional volume of PFR in the NEM to increase the resilience of the power system.[29]

The 25 August 2018 separation event

Due to the relative infrequency and variability of non-credible contingency events, it is difficult to compare different non-credible contingency events and the system's response to them over time. However, AEMO highlights the system's behaviour during the 25 August 2018 separation event as representative of the current capability of the NEM to respond to large non-credible contingency events.

BOX 2: THE 25 AUGUST 2018 SEPARATION EVENT

The 25 August 2018 separation event saw the loss of the QNI inter-connector between the Queensland and New South Wales regions, followed by loss of the Heywood inter-connector

28 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.41.

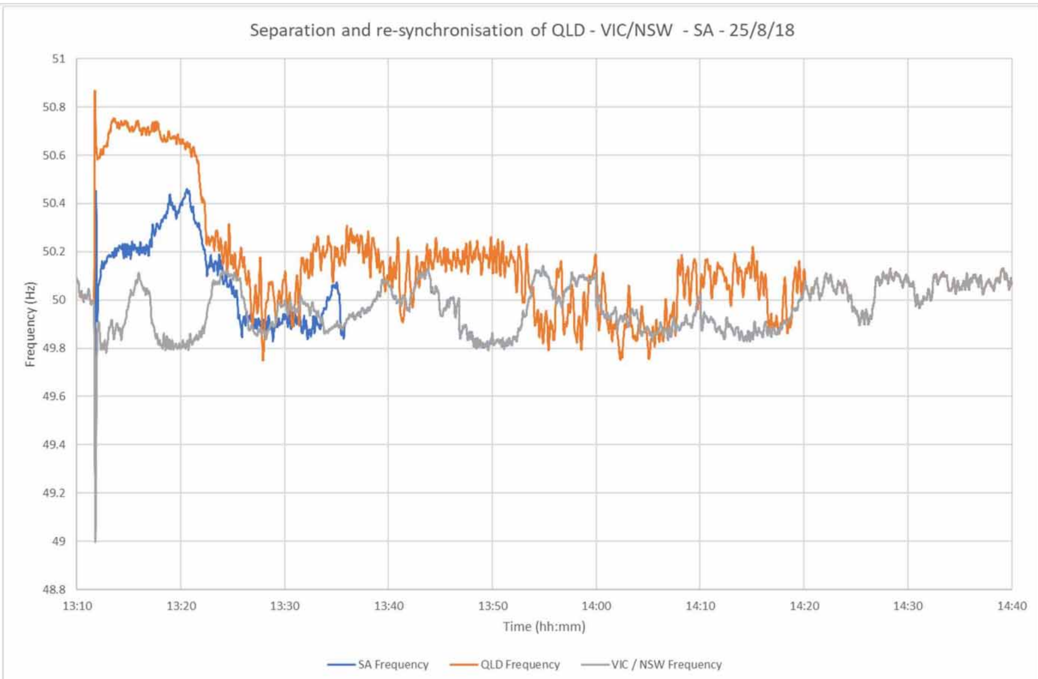
29 Ibid.pp.26 - 28.

between South Australia and Victoria. The two separations resulted in the interruption of 1078 MW of electricity supply to industrial loads in VIC, NSW, and Tasmania, and some residential and commercial customers in NSW.

The initial cause of the separation event was a single lightning strike on the transmission tower supporting the two circuits of the Queensland - New South Wales interconnector (QNI), creating faults on each circuit and, subsequently, a loss of synchronism between NSW and QLD. The resulting trip of the interconnector islanded the QLD region and interrupting 870 MW of power flow from QLD to NSW.

The QLD region experienced an immediate supply surplus and the regional frequency rose to 50.90 Hz. The remainder of the NEM experienced an immediate supply deficit. The rapid changes in power system conditions triggered the Emergency APD Portland Tripping scheme a few minutes later, separating SA from the NSW/VIC region. As SA was exporting at the time, it also experienced a supply surplus, raising the regional frequency to just below 50.5 Hz and contributing to the NSW/VIC region's supply deficit. The minimum frequency that the NSW/VIC region reached was 48.95 Hz. The frequency variation of each region is shown in figure 2.8 below.

Figure 2.8: Separation of regional frequencies following separation event on 25 August 2018



The QLD region remained in a satisfactory but not secure operating state for 68 minutes until it was resynchronised with the rest of the NEM, due to AEMO's inability to procure sufficient contingency FCAS in the islanded region. This was substantially longer than the maximum of 30 minutes AEMO is to target with best endeavours to restore the system to a secure state. Similarly, the frequency in the QLD region remained above 50.5 Hz for 608 seconds, breaching the FOS to restore frequency to within the NOFB within 10 minutes.

The separation event caused 985 MW of industrial load in NSW, VIC and TAS, and a further 99.3 MW of residential and commercial load in NSW to be shed through UFLS schemes. All interrupted load was eventually restored by 15:28, 77 minutes after the initial lightning strike.

Source: AEMO, Final Report — Queensland and South Australia system separation on 25 August 2018, 10 January 2019.

Note: 1 — The power system is said to be operating in a satisfactory state when the system variables, such as frequency, voltages and current flows, are within standards and ratings set out in the NER (Clause 4.2.2). The power system is in a secure operating state if, in AEMO's reasonable opinion, it is in a satisfactory operating state and will return to a satisfactory operating state following any credible contingency event or protected event (NER Clause 4.2.4). If the power system is not in a secure operating state for greater than 30 minutes, AEMO must review the provision and response of facilities and services and the appropriateness of actions taken to restore or maintain power system security (NER Clause 4.8.15).

While most power system equipment operated within the standards set under the NER, AEMO's view is that the aggregated system response on 25 August 2018 did not meet expectations for power system resilience. AEMO's analysis of the event highlights a decline in frequency control capability and system resilience to events larger than single credible contingencies in the NEM.

AEMO also stated that the occurrence of this event demonstrated a substantial reliance on automatic UFLS to rebalance supply and demand following contingency events in excess of the single largest credible contingency event. In its rule change request, *Mandatory primary frequency response*, AEMO noted that although UFLS is a valid tool for frequency control under the NER, UFLS should only be used as a last resort measure to protect against system failure. This is due to both physical limitations, and the need to ensure robustness. UFLS lacks the precision needed to keep supply and demand closely matched, often resulting in more load being shed (and a longer period of outage) than is strictly necessary.[30]

AEMO published a report detailing its findings from an investigation of this operating incident. In the report, AEMO identified two key factors that increased the reliance on load interruption to rebalance power system demand with supply on 25 August 2018:[31]

1. limited or no PFR provision from many generators,
2. the distribution of FCAS reserves across the NEM at the time of the event.

These factors were generally not the result of incorrect system or generator operation, but instead were a product of the current arrangements for procuring and providing frequency response services in the NEM. AEMO states that:

> While most Generators met their obligations for frequency response under their performance standards and FCAS dispatch, the lack of frequency response from some generating systems contributed to significant technical challenges in arresting and

30 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.15.

31 AEMO, Final Report — Queensland and South Australia system separation on 25 August 2018, 10 January 2019, p.6.

controlling power system frequency, particularly in the earlier stages of the event.

A more detailed analysis of generating unit response reveals that there were issues in the provision of PFR following the separation event from all types of generating plant. AEMO found many generators responded incorrectly or too slowly to correct the initial frequency excursions experienced in the event, further demonstrating a need for additional PFR provision to limit the impact of contingency events. These findings are summarised in Table 2.1.

Table 2.1: **Frequency response by generation type on 25 August 2018**

GENERATION	PERCENTAGE OF TOTAL GENERATION OUTPUT	RESPONSE
Synchronous	~83%	As the key generation technology online during this event, response from synchronous generation was a key factor in power system outcomes. Several large generating systems either did not adjust output in response to local changes in frequency, only responded when frequency was outside a wider band than has been observed in the past, or limited, or restricted, their response to frequency changes. Large oscillatory changes in output were observed from some generating units.
Distributed PV	14%	Generally contributed to lowering frequency in SA and QLD by reducing output, but was unable to assist in VIC or NSW, as those regions needed an increase in supply. Approximately 15% of sampled systems installed before October 2016 disconnected and, of those installed after October 2016, around 15% in QLD and 30% in SA did not demonstrate the over-frequency reduction capability required by AS/NZ4777.2-2015.
Large-scale solar PV	2.3%	Generally contributed to lowering frequency in SA and QLD but did not assist in limiting the initial frequency excursions due to slow response speed.
Wind	1.2%	Did not assist in correcting the frequency deviations.

GENERATION	PERCENTAGE OF TOTAL GENERATION OUTPUT	RESPONSE
		Four wind farms in SA reduced output to zero due to an incorrect protection setting.
Large-scale battery	<0.1%	Assisted by containing the initial decline in power system frequency, and then rapidly changed output from generation to load to limit the over-frequency in SA following separation from VIC.

Source: AEMO

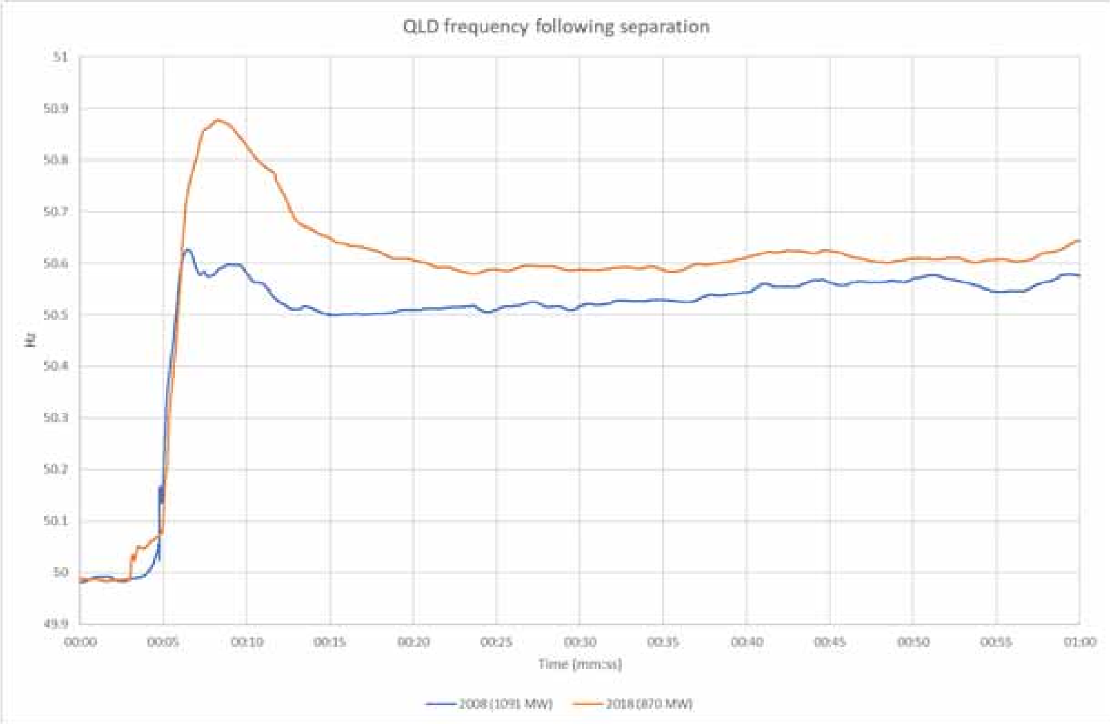
Comparison to the separation event on 28 February 2008

The last time QLD separated from the rest of the NEM was on 28 February 2008, where an event in NSW led to the loss of the QLD-NSW DC inter-connector, Directlink, followed by the loss of QNI. Frequency excursions were generally extreme during the 2008 event and no load shedding occurred, despite the fact that QNI export to NSW at the time of the event was 221 MW greater than on the 25 August 2018.

No two power system disturbances are ever the same, and AEMO acknowledge that there are material differences in power system conditions between the two events, particularly outside of QLD. However, AEMO considers the differences in system outcomes between the two events are noteworthy, especially with respect to the QLD region.

The spread of maximum frequency experienced in QLD in 2018 as compared with 2008 provides evidence that the power system's resilience to large contingencies over the last ten years has declined, as does the significant shedding of load required in 2018 to arrest an event with a similar, but larger, initiating trigger in 2008. This decline is depicted in Figure 2.9.

Figure 2.9: Frequency performance in QLD during the 2008 and 2018 separation events



Source: AEMO

In comparing these two events, AEMO also made the following additional observations on the effects of insufficient PFR on the degradation of frequency performance following contingency events in the NEM:

- A range of disparate frequency control actions occurred in 2018, including some that combined to exacerbate frequency deviations. Additional PFR would have counteracted or stabilised some of these outcomes.
- PFR from some new generating systems installed after the 2008 event was delayed to the point where it made little or no contribution to arresting the initial frequency deviation after the initial disturbance.
- Similar-technology asynchronous generating systems installed after 2008 tripped because of the operation of near-identical frequency protection settings and poor ongoing control of frequency. Additional PFR would have reduced the likelihood of this outcome.

Historically, generation PFR beyond the procured FCAS reserves could broadly be relied on to minimise the probability of such load interruption. AEMO's analysis of this event demonstrated this is no longer the case.

AEMO's recommendations following the 25 August 2018 Separation Event

AEMO's operating incident report includes eight recommendations, including some intended to improve the resilience of the power system to contingency events in excess of the largest credible contingency event. AEMO's principal recommendation in the final incident report is the implementation of interim actions, through rule changes as required, to deliver sufficient primary frequency control in the NEM. This recommendation is consistent with the actions set out in the frequency control work plan published as part of the final report for the AEMC's *Frequency control frameworks review* in July 2018.

AEMO's investigation of the 25 August event illustrated the extent of the decline in power system frequency performance, and the need for immediate measures to arrest it. AEMO made several recommendations to address this decline in frequency performance, including a primary recommendation for:

a) AEMO to work with the AEMC, AER and NEM participants to establish appropriate interim arrangements, through rule changes as required, to increase primary frequency control (PFC) responses at both existing and new (synchronous and non-synchronous) NEM generator connection points where feasible, by Q3 2019.

b) AEMO to support work on a permanent mechanism to secure adequate PFC as contemplated in the AEMC's Frequency Control Framework Review, with the aim of identifying any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.

AEMO's *Mandatory primary frequency response* rule change proposal addresses the first of these recommendations, in part.

2.2.3 Power system frequency stability

AEMO has found that the power system is demonstrating ongoing oscillations of frequency and that power system frequency is increasingly uncontrolled between the boundaries of the NOFB. AEMO considers that frequency instability in the NEM:

- decreases power system resilience
- results from a lack of PFR within the NOFB
- cannot be adequately addressed using the tools currently available to AEMO

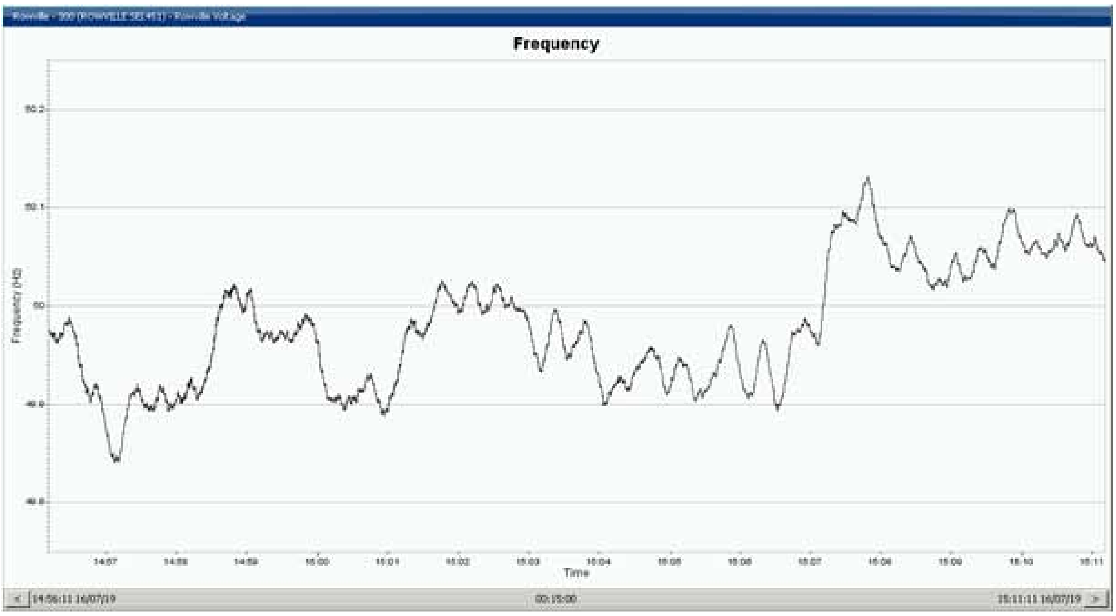
AEMO's technical advice from Dr John Undrill also identifies that the NEM exhibits ongoing, poorly damped frequency oscillations under normal condition. [32] The advice from Dr John Undrill is discussed further in section 2.5.

A typical 15-minute snapshot of NEM frequency is shown below in Figure 2.10, where the periodic 20-30 second oscillations in system frequency can be clearly observed. On-line monitoring tools available to AEMO indicate that the halving time of these oscillations

32 John Undrill, Notes on Frequency Control for the Australian Energy Market Operator, 5 August 2019, p. 13.

routinely exceeds the 5 second halving time standard outlined in the NER. AEMO considers that this system behaviour does not meet established norms for damping of power system oscillations consistent with good electricity industry practice.

Figure 2.10: Frequency instability over a typical 15-minute interval in the NEM



Source: AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p. 24.

AEMO also considers that it does not have adequate frequency control tools to address this frequency instability. As stated in AEMO's *Mandatory primary frequency response* rule change request:

> The tools currently available to AEMO do not ensure the stable control of frequency under normal conditions, and instead result in an arrangement where frequency is moving in an increasingly uncontrolled and unstable manner across the entire 300 mHz range of the NOFB.

PFR within the NOFB is required to dampen small frequency deviations that occur around 50Hz. The lack of stable control of frequency around 50 Hz allows frequency to remain near the edges of the NOFB for significant periods. This increases the potential for load shedding and subsequently decreases the resilience of the power system to contingency events through the erosion of the NOFB buffer.

2.3 Drivers of frequency performance degradation

The *Frequency control frameworks review* identified the key drivers of the recent degradation of frequency performance as being; [33]

- a reduction in frequency response during normal operation due to generators making changes to their control systems that effectively decrease or remove their responsiveness to frequency deviations within the normal operating frequency band
- the effectiveness of AEMO's AGC system and the amount of regulating FCAS AEMO procures.

Through the *Frequency control frameworks review* the Commission also described how increasing variability of supply and demand is making the task of managing system frequency more challenging.

- Section 2.3.1 describes the impact of the reduction of voluntary frequency response from synchronous generators.
- Section 2.3.2 describes the impact of regulation FCAS on frequency performance
- Section 2.3.3 describes the impact of increased variability of electricity generation and load on frequency performance

An overview of how governors work and the history of governor requirements is provided in Appendix E.

2.3.1 Removal of frequency responsiveness by synchronous generators

One of the main drivers of the recent degradation of frequency performance is generators decreasing or removing the responsiveness of their plant to frequency deviations to avoid actual and perceived dis-incentives associated with operating their plant in a frequency responsive mode. This has occurred as a result of generators:

- widening their governor deadband such that they are less responsive to frequency changes
- upgrading older mechanical governors to digital control systems, which enable a generator to counteract its mechanical governor response and easily change the frequency response mode of the generator.
- Where it is more difficult or costly to change their governor settings and uneconomic to upgrade to digital systems, the installation of secondary control systems to dampen the primary governor response of their generating units, in favour of maintaining alignment of generator output with dispatch targets

The net result of these changes to generator control systems is a reduction in the level of PFR that contributes to maintaining the power system frequency within the NOFB and following large contingency events.

33 AEMC, 26 July 2018, *Frequency control frameworks review* — Draft report, p.42.

Currently, the NER does not include a regulatory requirement for generators to provide PFR unless they are enabled to provide contingency FCAS through the ancillary service markets. As such, the only PFR that is provided in the NOFB is done so voluntarily. A more detailed description of the history of governor response in the NEM is included in appendix b.

A number of generators acknowledge making changes to the governor settings to detune responsiveness to frequency variations. In its submission to the *Frequency control frameworks review*, AGL confirmed that the droop control on the Loy Yang power station has been disabled in order to avoid exposure to causer pays event.[34] Similarly, Stanwell noted that there has been an observed reduction in the provision by generators of free PFR in the power system.[35]

The AEMC recognises that as some generators reduce or remove their responsiveness to frequency deviations, those that remain experience a greater impact on plant operation, including associated wear and tear costs. This, in turn, strengthens the incentives for generators to further reduce their provision of PFR, continuing the decline in frequency control in the NEM.

2.3.2 Regulation FCAS volumes

Through submissions to the *Frequency control frameworks review, s*takeholders raised concerns that the levels and performance of regulating FCAS may be contributing to the degradation of frequency performance during normal operation. As discussed in section 2.6.1, AEMO is actively reviewing the effectiveness of its AGC system to improve frequency performance, and has recently increased the base procurement quantities for regulating FCAS in response to poor frequency performance.

As described in section 2.1.1, AEMO can purchase regulating raise and regulating lower services to maintain the power system frequency within the NOFB defined in the frequency operating standard. AEMO procures regulation services via a base amount and a variable additional component that is procured based on the level of accumulated time error. Currently, the maximum value of regulation raise and lower is capped at 250MW.[36]

A record of the historical changes in the global quantity of regulation raise and lower services is found in the documentation for the NEMMCO FCAS review that was completed in July 2007. The base quantity for global regulation raise and lower services was progressively reduced from 250MW prior to July 2003 to 130MW for global regulation raise and 120MW for global regulation lower from June 2006.[37] At the time, NEMMCO analysis found that a reduction in the quantity of global regulation services would not significantly impact the chance of the frequency exceeding the NOFB.[38]

In line with the Frequency control work plan, AEMO has recently increased the base component for its procurement of regulation raise and lower services. Prior to 22 March

34 AGL, Submission to the *Frequency control frameworks review* — issues paper, 6 December 2017, p. 3.

35 Stanwell Corporation, Submission to the *Frequency control frameworks review* — issues paper, 18 December 2017, p. 4.

36 AEMO, Constraint implementation guidelines, June 2015, p.27.

37 NEMMCO, Frequency control ancillary services review – issues paper, December 2006, p.15.

38 NEMMCO, Frequency control ancillary services review – final report, July 2007, p. 62.

2018, the base volumes of regulation FCAS were 130MW and 120MW for raise and lower respectively. The existing quantity of global regulation FCAS has a base component of 220MW for lower, 230MW for raise, and a variable additional component that is procured based on the level of accumulated time error.[39]

Although AEMO has since increased the base levels of regulation FCAS, it is noted by AEMO that increased regulation FCAS volumes are not a solution to frequency control in and of themselves.[40] The interactions and reliance of secondary frequency control such as regulation FCAS on inertia and PFR is discussed in section 2.1.2.

2.3.3 Generation and load variability

In addition to the reduced capability of the traditional fleet of generators to provide frequency control services, supply and demand in the NEM has become increasingly variable and less predictable due to the growing penetration of variable renewable generation and greater demand side involvement. Specifically, an increased potential for imbalances between electricity demand and supply is driven by:

- changing frequency control capability
- increased variability and unpredictability of supply and demand.

These drivers are creating challenges for conventional forms of frequency control in the NEM and making it more challenging for AEMO to manage power system security.

Similarly, the regulating and contingency FCAS markets have historically attracted participation by synchronous generation. The withdrawal of synchronous generation, therefore, also contributes to a reduction in the availability of these services in the NEM. Although new technologies like batteries and demand side response are replacing some of the traditional providers of FCAS capacity, this is an area of continuing development for inverter based technology. Inverter based technology does not provide an inherent automatic frequency response but can be programmed to do so. However, plant such as the Hornsdale Power Reserve battery have competitively participated in the FCAS markets since 2017. Some of these technologies offer the potential to provide frequency response services that act much faster than the existing services, perhaps as quickly as a few hundred milliseconds.[41]

Furthermore, variable renewable technologies such as wind and solar can change output quickly due to sudden changes in localised weather conditions. Solar plant can experience 50% reductions in power reduction within minutes due to local cloud cover.[42] Sudden changes in output from non-dispatchable variable renewable generation within a dispatch interval can increase the level of uncertainty in the dispatch process, which may increase the amount of FCAS needed to maintain frequency within the requirements of the frequency operating standard.

39 AEMO, Regulation FCAS changes – June update, June 2019.

40 AEMO, Mandatory primary frequency response - Electricity rule change proposal, 16 August 2019, p.37.

41 AEMC, 26 July 2018, *Frequency control frameworks review* - Final report, pp. 25-26.

42 AEMO, Advice to the Frequency control frameworks review, March 2018, p.15.

In aggregate, increased variability of supply and demand in the NEM makes the task of controlling system frequency more challenging.

2.4 International approaches to PFR

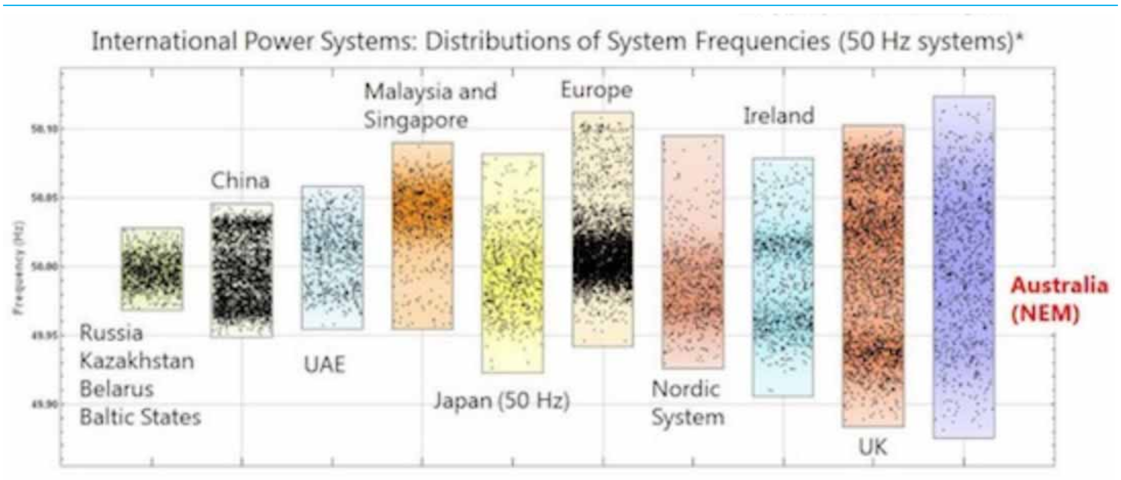
Most international power grids have some arrangement for provision of PFR. The exact mechanism varies by jurisdiction from regulatory mandates to market based systems, or a mixture of both. AEMO identifies in its rule change request, *Mandatory primary frequency response*, that:[43]

> A key point of difference between the NEM and other power systems is that the regulatory frameworks and market bodies do not treat the provision of PFR under normal operating conditions separately from the provision of PFR following disturbances

In addition, most jurisdictions (with the exception of New Zealand) impose maximum dead bands for PFR tighter than the NOFB of the NEM(as per the setting in the Market ancillary service specification for contingency FCAS). As such, the NEM is unique in the fact that secondary frequency control (regulation FCAS) provides the only certain frequency response between during normal operation.[44]

The lack of a mechanism to provide narrow band PFR contributes to a large spread of operational frequencies in the NEM in comparison to international grids, as illustrated in Figure 2.11.

Figure 2.11: Frequency variance in international power systems



Source: AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.31.

43 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.31.

44 Ibid.

The AEMC published a summary of international arrangements for PFR as part of the draft report for the *Frequency control frameworks review*. Appendix E contains a summary table of the different global mechanisms and parameters for PFR provision based on AEMO's review from its rule change request, *Mandatory primary frequency response*, and the AEMC's previous summary of international arrangements from the *Frequency control frameworks review.*

2.5 AEMO's international expert advice

To inform AEMO's approach to improving frequency control in the NEM, AEMO has sought the technical advice of Dr John Undrill, a power system and frequency response expert. Dr Undrill was tasked by AEMO to "further assess the appropriateness of NEM frequency control arrangements against typical international practice, and what changes may be required to alter NEM frequency outcomes".[45]

The key recommendation provided in Dr Undrill's advice to AEMO is that:[46]

> The obligation to provide primary control response to variations of frequency should be applied to the widest practical part of the generating fleet. The obligation should apply, to the extent that it is practical, to all generating resources including those that are coupled to the grid through electronic inverters.

Dr John Undrill is a respected international consultant, formally of GE Energy, a fellow of IEEE and has recently prepared similar advice for NERC. Dr Undrill's advice to AEMO, titled *Notes on frequency control for the Australian Energy Market Operator*, was submitted alongside AEMO's mandatory PFR rule change request and is available on the AEMC project page for ERC0274.

Summary of Dr Undrill's Advice

In summary, the technical advice states that the NEM operates with "very limited primary [frequency] control capability", leaving management of frequency predominantly to secondary frequency control mechanisms that are not effective in and of themselves. Dr Undrill's key findings are that frequency in the NEM is:[47]

- ineffectively controlled, or uncontrolled, between $\pm$0.150 Hz (i.e. within the NOFB),
- well controlled when it reaches the edges of the NOFB, 49.85Hz — 50.15Hz.
- following contingency events, more likely to experience larger deviations and risk triggering UFLS due to the frequency variability in normal operation.

Dr Undrill also advises that the unique nature of the transitioning NEM should therefore be operated with conservative security margins to protect against novel or non-traditional power system events.[48]

45 AEMO, Electricity rule change proposal — Mandatory primary frequency response, August 2019

46 John Undrill, *Notes on Frequency Control for the Australian Energy Market Operator*, 5 August 2019, p. 3

47 Ibid., pp.25-26

48 Ibid., p.2

> Australia is at the forefront of incorporating electronically coupled generation into its fleet and therefore must be prepared to encounter equipment characteristics and operational behaviour that are outside the range of practical experience.
>
> [...]
>
> Accordingly, prudence asks for electronic equipment to be operated at frequencies that are well within the frequency band specifications given to equipment developers.

The technical advice concludes with the following recommendations to improve frequency performance in the NEM:[49]

- All generators, including asynchronous generators, should be obliged to provide a PFR with a deadband no wider than $\pm$0.015 Hz. deadbands and droop settings should be as uniform as possible across the fleet in the interest of equitable contribution to PFR.
- Governor control systems should be set up so that PFR is sustained for the duration of a frequency deviation
- The market rules should be modified such that there is no perception that punitive action is risked for operating in a frequency responsive manner. Financial rewards for contribution to frequency control may also be worthwhile.

2.6 Related work programs

2.6.1 AEMO actions to improve frequency performance

To date, as part of AEMO's responsibilities in the Frequency Control Work Plan, AEMO has completed three key actions to improve frequency performance in the NEM:

1. A survey of generator frequency control settings has made AEMO aware that there is a wide and complex array of control settings in use.
2. A trial of increased primary frequency response in Tasmania resulted in immediate improvement in frequency control for the region.
3. Revisions to the causer pays procedure such that it ignores four second samples where the frequency indicator and system frequency in an area are mismatched.

In conjunction with this rule change request, AEMO is also currently undertaking several further actions related to frequency control using the tools currently available to them. These include:

- Reviewing the assumptions used to estimate load relief and increasing contingency FCAS volumes accordingly.[50]
- Reviewing regulation FCAS volumes, the base levels of which have been increased by 90 MW since March 2019.
- Considering the regional allocation of contingency FCAS to ensure geographical diversity of market procured PFR.

49 Ibid., p. 3

50 AEMO, *Changes to Contingency FCAS volumes*, August 2019.

- Further review of AGC performance following AGC tuning in 2018.
- Addressing how the Market Ancillary Service Specification (MASS) may cause FCAS enabled generators to delay or withhold early provision of PFR.

AEMO will review the MASS to reflect that plant enabled for contingency FCAS are also compliant with the MASS if their frequency response initiates within the NOFB.

More detail on all these actions can be found in AEMO's rule change requests.

2.6.2 AEMC BSE review

Some non-credible contingency events can have an impact on the power system substantially larger than the largest credible contingency event. As AEMO only procures precautionary services for credible contingencies during normal operation, these high impact, low probability contingency events (HILPs) can test frequency control mechanisms and threaten the security of the system. In a general sense, the ability of the power system to survive and recover from HILPs can be described as the “resilience” of the power system.

The AEMC's *South Australia black system event review* is currently ongoing with the aim to determine:[51]

> whether power system security frameworks are sufficient to manage high impact, low probability (HILP) events, and whether improvements in existing processes, tools available to the system operator or components of the electricity system in South Australia would assist in preventing future black system events.

In this review, the AEMC explains that the survival of the power system is a measure of the extent to which the functionality of the power system is degraded as a consequence of the high impact low probability event. The ability of the power system to survive a HILP event depends on:

- the technical performance of generating systems and network being maintained at a sufficiently high standard
- having sufficient inertia, system strength and other services within the power system to be able to ride through frequency and voltage disturbances, and
- the effective operation of special protection schemes and emergency frequency management schemes designed to shed load, generation or trip network elements in order to arrest the progress of a cascading outage.

Ultimately, the resilience of a power system is its ability to avoid uncontrolled, cascading failure. The provision of PFR is directly related to the second point above as a service that reduces the magnitude of frequency disturbances following HILP events. AEMO's submission to the *South Australia black system review* issues and approach paper supports PFR provision as an important factor in maintaining system resilience:[52]

> AEMO considers that efficient, planned provision of essential capabilities such as

51 AEMC, *South Australia black system review,* Issues and Approach Paper, 18 April 2019

52 AEMO, *Submission to AEMC Review of the black system event in South Australia: Issues and approach paper,* May 2019

> primary frequency response and reactive power support combined with appropriate infrastructure development and cyber security uplift will be critical to maintaining a resilient system.

2.7 Inertia and inertia support activities

Inertia is provided by large spinning machines that are synchronised to the grid and acts to slow the rate of change of frequency caused by a contingency event. The *Managing the rate of change of frequency* rule change published in September 2017 introduced the requirement for AEMO to maintain minimum levels of inertia throughout different regions of the NEM. Upon AEMO declaring an inertia shortfall in a NEM region, TNSPs must procure inertia network services through the construction and operation of synchronous condensers or entering into service agreements with synchronous plant.

As discussed in section 2.1.2 and section 2.1.3, inertia is integral to frequency control alongside primary and secondary frequency response. Inertia is defined in Chapter 10 of the NER as:

> Contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is electro-magnetically coupled with the power system and synchronised to the frequency of the power system.

Although inertia is only provided by synchronous equipment connected to the power system, other services, including frequency control services, can substitute the need for inertia provision if deemed appropriate by AEMO. These alternative services are called 'inertia support activities'.

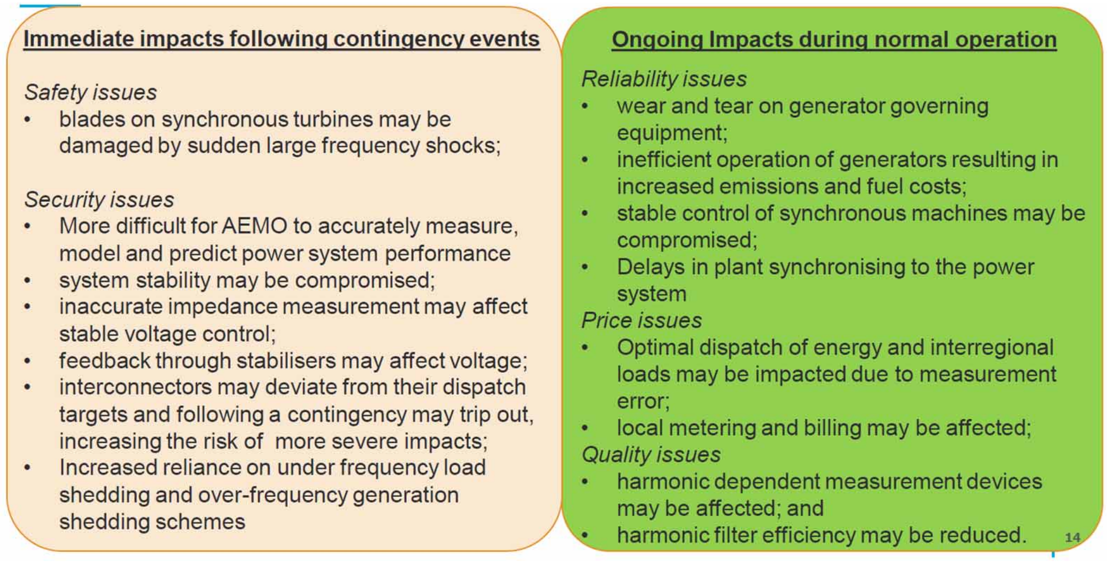
As such, the Rules also allow for the provision of 'inertia support activities' as services that decrease the minimum levels of inertia AEMO must procure, the value of these services being at AEMO's discretion, as set out in NER cl 5.20B.5:

> (a) AEMO may at the request of an Inertia Service Provider approve activities (inertia support activities) under this clause and agree corresponding adjustments to the minimum threshold level of inertia or the secure operating level of inertia for the purposes of clause 5.20B.4(b) where the activities:
>
> (3) AEMO is satisfied the activities will contribute to the operation of the inertia sub-network in a satisfactory operating state or secure operating state in the circumstances described in clause 4.4.4(a) or (b) as applicable.
>
> Note: Inertia support activities may include installing or contracting for the provision of frequency control services, installing emergency protection schemes or contracting with generators in relation to the operation of their generating units in specified conditions.

3 ISSUES RAISED IN THE RULE CHANGE REQUESTS

This chapter summarises the issues raised by AEMO and Dr Sokolowski in their rule change requests. Both proponents have highlighted a number of key consequences that poor frequency control may have on the NEM, summarised in Figure 3.1.

Figure 3.1: Overview of issues raised by in the PFR rule change requests



Source: AEMC

Stakeholders are encouraged to comment on the issues raised in the rule change requests.

3.1 AEMO — Mandatory primary frequency response

In its rule change request, *Mandatory primary frequency response*, AEMO identifies that frequency control in the NEM has declined to the point where AEMO is increasingly unable to control frequency in the NEM under normal operating conditions, due to reduced provision of PFR from generation.[53]

AEMO considers that currently available tools cannot effectively control frequency on an ongoing basis, and increasingly this is resulting in power system outcomes that AEMO regards as inconsistent with prudent industry practice. AEMO states that the decline in frequency control has led to ongoing oscillations of power system frequency across the full range of the NOFB. According to AEMO, the "resulting frequency performance of the NEM is outside the bounds and experience of frequency in other comparable power systems." AEMO is concerned that poor frequency control in the NEM makes it difficult to leverage international learnings in relation to the integration of new technologies, such as inverter

53 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.17.

connected generation. The result is that the NEM may be more exposed to the risk of unexpected operational impacts associated with these technologies, that are a relatively new part of modern power systems.

AEMO states that declining frequency performance is also reducing the resilience of the power system to disturbances, particularly those caused by contingency events that are greater than the largest credible contingency event. The consequences of the degraded frequency performance in the NEM are that:[54]

> - It increases the reliance on emergency frequency control schemes to manage such events, and with that reliance increases the risk of cascading failures leading to system collapse.
> - It reduces AEMO's ability to model and analyse the performance of the power system (especially for complex dynamic behaviour), which is essential for AEMO's ongoing management of power system security.

The following sections summarise AEMO's assessment of the implications of the decline in frequency control in the NEM:

- AEMO's difficulty in meeting the requirements of the Frequency operating standard is described in section 3.1.1.
- Ongoing frequency instability in the NEM is described in section 3.1.2.
- The risk of unexpected power system impacts following increasingly complex power system events is described in section 3.1.3.
- The increased reliance on load shedding for frequency control following large contingency events is described in section 3.1.4.
- AEMO's reduced ability to learn from otherwise comparable power systems is described in section 3.1.5.
- The reduction in the predictability of power system behaviour is described in section 3.1.5.

In addition, AEMO does not believe that the existing tools for managing frequency control can adequately address the decline in frequency performance, these concerns are summarised in section 3.1.7.

3.1.1 Difficulty meeting the requirements of the Frequency operating standard

AEMO has recently found that it has become difficult to meet the requirements of the frequency operating standard for power system frequency performance during normal operation, in the absence of contingency events.[55] [56] In particular:

54 Ibid., p. 18.

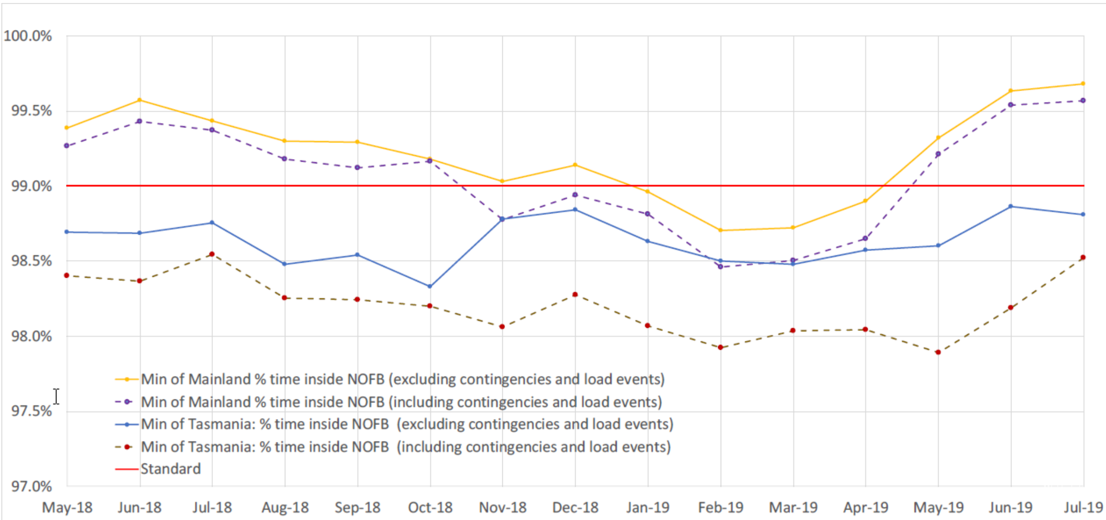
55 Ibid. pp. 22-26.

56 Clause A.1.2(b) of the Frequency operating standard requires that in the absence of a contingency event, AEMO should maintain system frequency within the applicable normal operating frequency excursion band, and should not exceed the applicable normal operating frequency band for more than five minutes on any occasion and not for more than 1% of the time over any 30 day period.

- In 2017-2018 there were 50 events in the mainland NEM and 295 events in Tasmania where frequency took longer to return to the NOFB than is allowed in the Frequency operating standard.
- Since April 2018, power system frequency in Tasmania did not meet the requirement in the Frequency operating standard to be maintained within the NOFB for 99% of the time, excluding contingency events. In Q1 2019, this requirement was not met in the mainland NEM.
- Despite AEMO increasing the base volume of regulation FCAS by 70% since March 2019, power system frequency performance has not significantly improved. Preliminary results indicate that the frequency is being maintained within the NOFB more of the time. However, frequency control and stability within the NOFB has not improved.[57]

Figure 3.2 shows the frequency performance in the mainland and Tasmanian power systems relative to the 99% requirement for maintaining the frequency within the NOFB:

Figure 3.2: 30-day rolling average of percentage of time frequency is within the NOFB



Source: AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p. 23.

3.1.2 Ongoing instability in NEM frequency

As discussed in section 2.2.3, the power system in the NEM is exhibiting ongoing frequency oscillations. AEMO's recent investigations have found that the NEM is increasingly uncontrolled under normal operating conditions. As noted in AEMO's rule change request, *Mandatory primary frequency response*:[58]

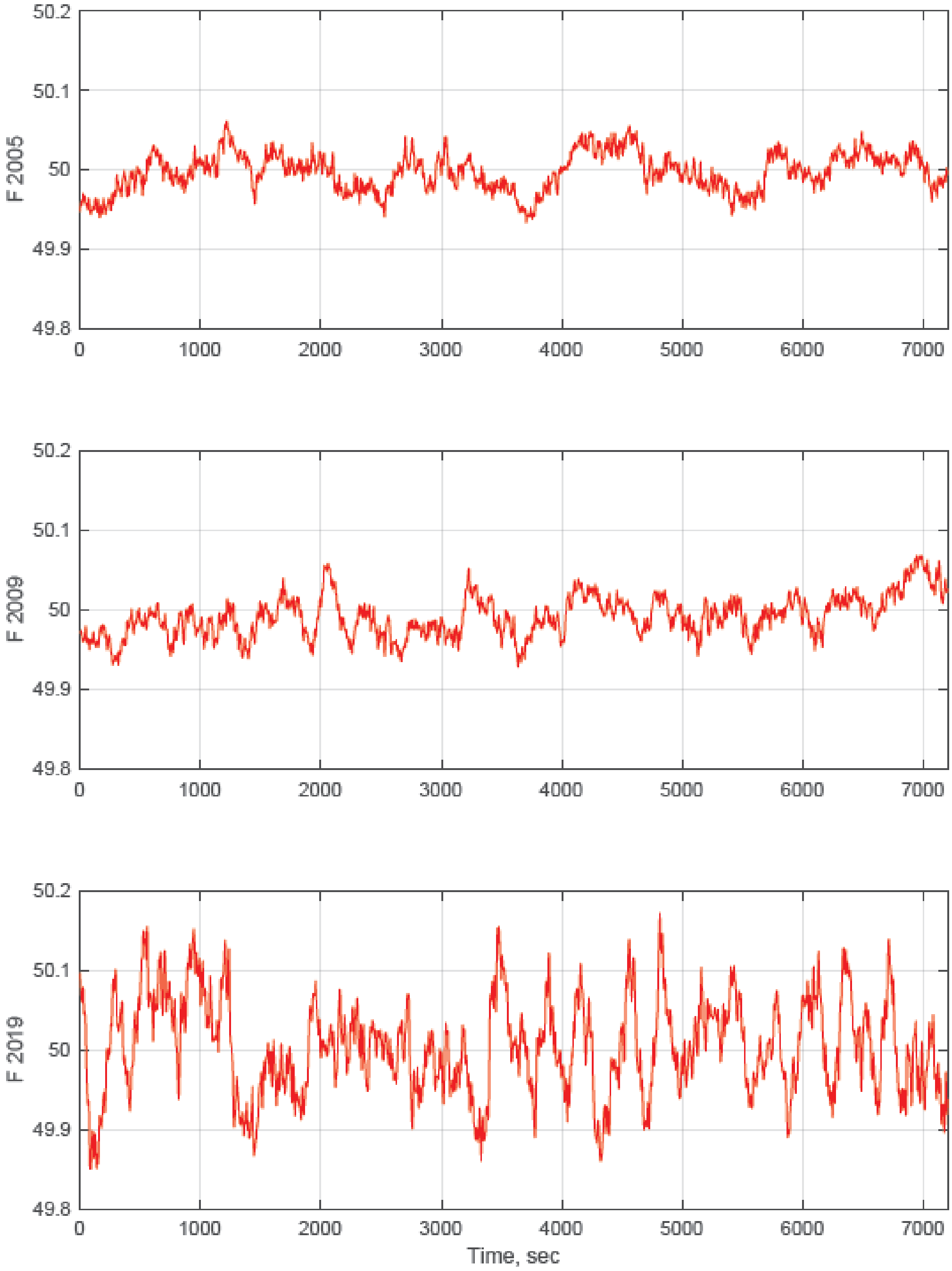
57 Ibid. pp.36-37.

58 Ibid, p. 23-24.

NEM frequency under normal conditions increasingly exhibits continual oscillations with a period of 20-30 seconds. On-line monitoring tools available to AEMO indicate that the halving time of these oscillations routinely exceeds the 5 second halving time standard outlined in the NER.

The increased incidence of frequency oscillations between 2005 and 2019 can be seen in the following figure taken from frequency control advice recently provided to AEMO by John Undrill:

Figure 3.3: Increased frequency oscillations in the NEM power system



Source: John Undrill, Notes on Frequency Control for the Australian Energy Market Operator, 5 August 2019, p. 17.

Note: 1000 seconds is approximately equivalent to 16 minutes and 40 seconds.

Schedule 5.1.8 of the NER sets out the criteria for stable operation of the grid that must be used by NSPs when conforming with the system standards required of them under Schedule 5.1. Further requirements for stability are set out in the power system stability guidelines prepared by AEMO in accordance with clause 4.3.4(h) of the NER. These guidelines detail the policies governing power system stability so as to facilitate the operation of the power system within stable limits. The stability of the power system frequency is typically a concern following a contingency event, when instability is more likely to occur. Frequency stability is also a power system requirement in the absence of a contingency event, during normal operating conditions. The System stability guidelines describe frequency instability as resulting in:[59]

> an uncontrolled sustained increase or decrease over time (a "run-away" condition) or sustained undamped oscillatory behaviour.

The ongoing frequency oscillations described by AEMO above are an example of 'sustained undamped oscillatory behaviour'.

An explanation of concepts related to frequency stability is included in appendix a.

3.1.3 Power system events are becoming more complex

In its rule change request, *Mandatory primary frequency response*, AEMO states that power system events are becoming more complex and that poor frequency control increases the risk of unexpected power system impacts following contingency events. Recent power system events, such as the separation event on 25 August 2018, demonstrate that actual power system behaviour following disturbances can deviate significantly from expected power system behaviour. AEMO notes that:[60]

> When PFR is limited to a small number of providers, the power system has lower immunity to detrimental behaviour of individual plant, as each item of plant has a greater ability to affect power system frequency. A power system with PFR from a wider range of providers has much greater control and can resist or damp power system outcomes that result from one, or a group of mal-operating generating units.

3.1.4 Increased reliance on load shedding

The current FCAS arrangements only allow AEMO to procure sufficient contingency FCAS reserves to rebalance supply and demand following a simple credible contingency event. The design of the current arrangements do not allow any margin beyond these levels. As a result, the current arrangements require the operation of under frequency load shedding schemes to rebalance supply and demand following the sudden unexpected loss of generation in excess of the largest credible contingency event.

AEMO believes that:[61]

59 AEMO, *Power system stability guidelines*, 25 May 2012, p. 12.

60 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.24.

61 Ibid., p. 25.

> It is not acceptable to operate with no resilience against events that exceed the procured volume of Contingency FCAS and, by design, to proceed immediately to involuntary interruption of customer load.

And that:[62]

> it is essential to rebuild and maintain these margins to provide resilience against the more complex events now occurring on the power system, which are unpredictable in extent and increasingly go beyond the simple contingency events considered in the Contingency FCAS market design.

3.1.5 Reduced ability to learn from comparable power systems

In its rule change request, *Mandatory primary frequency response,* AEMO asserts that the degree of frequency variability in the NEM is well outside long-standing international norms and that this reduces AEMO's ability to learn from otherwise comparable power systems. As a result, AEMO believes that the NEM is more exposed to unexpected and previously unknown power system phenomena.

As noted by AEMO in its rule change request:[63]

> The NEM is increasingly operating with world-leading penetration levels of inverter connected generation. With respect to matters such as grid strength, system stability and system modelling the NEM is arguably operating at the very edge of existing knowledge and experience. Simultaneously, it is operating with levels of ongoing frequency variability that are well outside long-standing international norms and experience.
>
> This combination of factors makes it far more difficult for AEMO to learn from or apply the experience of other system operators worldwide regarding the appropriate management of high levels of inverter connected generation.

3.1.6 Power system behaviour is less predictable.

AEMO's rule change request, *Mandatory primary frequency response,* outlines that there is currently a lack of consistency and certainty as to how generating plant will respond to variations in power system frequency. According to AEMO, this uncertainty is undermining its ability to accurately model the power system, understand the causes of power system events and design and operate emergency frequency control schemes.[64]

AEMO increasingly relies on dynamic system modelling tools to assess the level of power system operating security close to real time. AEMO notes that:[65]

62 Ibid.
63 Ibid., p.25.
64 Ibid., pp. 25-26.
65 Ibid., pp. 25-26.

> A lack of consistency and certainty of PFR delivery from generation when making these assessments makes these tools less accurate, and consequently, less useful. It also creates uncertainty about the true operating limits of the power system.

AEMO has experienced difficulties in investigating and understanding the causes of power system incidents. AEMO's recent investigation of the separation event that occurred on 25 August 2018 was undermined by a divergence between expected generation response to the power system disturbance compared with the actual observed responses.[66]

The design of UFLS, OFGS and other emergency frequency control schemes relies on predictable generator behaviour to inform AEMO's power system models. AEMO notes that:[67]

> If generator control system parameters change based on FCAS enablement, the range of possible responses from generation becomes very broad, complicating scheme design and, potentially, compromising scheme performance.

3.1.7 Adequacy of the existing tools to improve frequency control

In its rule change request, *Mandatory primary frequency response*, AEMO sets out its reasoning as to why the existing frequency control tools are unable to address the decline in frequency performance in the NEM. This reasoning includes that:[68]

- The existing market ancillary services are unable to deliver effective frequency control on their own in their current form, in particular:
  - The arrangements in AEMO's Market ancillary service specification incentivise providers of contingency FCAS to commence their active power response once frequency exits the NOFB.
  - In the absence of PFR within the NOFB, Regulation FCAS, controlled centrally by AEMO's AGC system, is unable to effectively control power system frequency.
- Sole reliance on providers of contingency FCAS providers to respond to contingency events reduces the resilience of the power system by eroding operating margins.
- The protected event framework is unable to be utilised to restore effective frequency control during normal operation. While this framework is focused on helping AEMO reduce the risk of cascading failure following specific non-credible contingency events, AEMO have concerns as to the practicality of this framework to adequately support power system resilience in the NEM.[69]

3.1.8 Urgent need for regulatory change

As mentioned in section 1.1.1, AEMO has requested that the AEMC progress its rule change request, *Mandatory primary frequency response*, in the shortest reasonable time frame,

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66 Ibid., p.26.

67 Ibid., p.26.

68 Ibid., pp. 26-28.

69 The AEMC is reviewing the broader arrangements for power system resilience as part of its *Review of the system black event in South Australia on 28 September 2016*. On15 August 2019 the AEMC published a discussion paper for this review setting out a number of potential mechanisms that are being considered to enhance the resilience of the national electricity system.

balancing the requirement for appropriate consultation with the potential consequences of the ongoing lack of effective frequency control in normal operating conditions. AEMO recognises that the proposed rule is a significant change to the regulatory framework for the NEM, but at the same time the power system assumptions on which the frequency control frameworks were designed have changed and such a significant change is now urgently required. As noted in the rule change request by AEMO:[70]

> Increasing the frequency stability and the resilience of the power system cannot be delayed until a new market mechanism for PFR is debated, designed, trialled and implemented.

AEMO sets out the following reasons why a regulatory change to provide for effective frequency control in the NEM is now required without delay:[71]

- Power system frequency performance during normal operation continues to decline and the events of 25 August 2018 demonstrate the system is now less resilient to contingency events slightly larger than the largest credible contingency event.
- Previously held assumptions of power system behaviour following contingency events are no longer valid, this increases the risk of unexpected outcomes and decreases AEMO's ability to prevent load or generation shedding, and even cascading failure.
- There is now an increased probability of load or generation shedding events. AEMO also note that the rapid and ongoing increase in distributed rooftop PV generation undermines the effectiveness and predictability of UFLS in some regions of the NEM. AEMO believes that UFLS and OFGS should be reserved for managing only the most extreme events where no other options are available. AEMO does not believe it is appropriate that these schemes should be used where there is response capability available from existing generation that would minimise or prevent the use of these emergency, last resort options.
- The NEM is currently experiencing a rapid rate of connection of new generation, with 7GW of committed projects and 53 GW of proposed projects.[72] AEMO is concerned that:[73]

  > Delaying the implementation of a new rule requiring PFR will result in a significant volume of new generation being connected without any requirement to operate in frequency response mode except when it is dispatched to provide a market ancillary service.

- AEMO expects that the commencement of the *Five-Minute Settlement Rule* on 21 July 2021 will increase the challenge of controlling frequency in the NEM. This is based on the expectation that generators will respond to the incentives presented by the shorter

70 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.43.

71 Ibid. pp.41-44.

72 AEMO, Generation Information, 8 August 2019.

73 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, pp.42-43.

settlement time frame by more rapidly increasing or decreasing their output. As a result:[74]

> If broad-based PFR is not available by that date, AEMO expects it will be significantly more difficult to maintain power system frequency to meet the requirements of the FOS both under normal operating conditions and following contingency events.

- AEMO maintains that the physical needs of the power system, in relation to secure operation, are paramount to economic considerations.[75] AEMO considers that:[76]

> It would not be prudent to assume that any mechanism that continues or builds upon the design assumptions of the current FCAS arrangements will ultimately be successful. In contrast, the approach proposed in this rule change is entirely consistent with long-standing and demonstrably effective industry practice.

QUESTION 1: ISSUES RAISED BY AEMO IN ITS RULE CHANGE REQUEST, *MANDATORY PRIMARY FREQUENCY RESPONSE*

In relation to AEMO's rule change request, *Mandatory primary frequency response*:

- What are stakeholders views on the issues raised by the AEMO in its rule change request, *Mandatory primary frequency response*?
- Do stakeholders agree with AEMO's assessment that regulatory change is required as a matter of urgency to restore effective frequency control in the NEM?
- What are stakeholders views on AEMO's definition of effective frequency control as requiring narrow band frequency response from as large a portion of the generation fleet as is practical?
- Are there any other related issues or concerns that stakeholder have in relation to frequency control during normal operation and following contingency events?

3.2 Dr Sokolowski — Primary frequency response requirement

In his rule change request, *Primary frequency response requirement*, Dr Sokolowski identifies the following issues related to the degradation of frequency control in the NEM: [77]

- Safety and equipment reliability

  Lack of PFR increases the magnitude of frequency deviations following contingency events which, combined with the greater variability of frequency in the NOFB, increases the risk of damage to generation equipment. Damaged equipment is more susceptible to

74 Ibid. pp.43.

75 AEMO, Submission to the *Frequency control frameworks review* — Draft Report, 26 April 2018, p.8.

76 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, pp.42-43.

77 Dr Sokolowski, *Primary frequency response requirement* — Electricity rule change proposal, 30 May 2019, pp.4-5.

catastrophic failure following contingency events or other operational triggers and can pose a significant risk of harm to plant operations staff.

- Reliability of supply

  Poor frequency performance within the NOFB may impose additional material wear and tear on generator governing equipment as the generator is required to respond to larger frequency deviations more of the time. This variability of operation may adversely impact the stable control of synchronous machines and reduce the operating efficiency of synchronous generators.

- Security
  - System stability may be compromised, for example as a result of oscillations of power system frequency of the form described by AEMO in section 3.1.
  - Feedback through power system stabilisers may affect voltage control.
  - Power flow on inter-connectors may deviate from their dispatch targets and following a contingency may exceed acceptable limits and lead to cascading failure.
  - The accuracy of the measurements of quantities relating to the power system state, relies on a relatively constant power system frequency close to the nominal level of 50Hz. Increased frequency variation may compromise the accuracy of such measurements, reducing AEMO's awareness of the security of power system operation and affecting the stable control of voltage.
  - Increased difficulty controlling power system frequency after system breakup events.
  - Increased reliance on load shedding to arrest frequency decline after the loss of a generating unit.
- Price
  - Dispatch of energy and interregional loads may no longer be optimised owing to measurement error. NEMDE optimises the dispatch of energy to meet demand while minimising the market cost, assuming a system frequency of 50Hz when forecasting demand. Deviations in frequency away from 50 Hz may contribute to forecast error due to the effect of frequency changes on the amount of power used by loads, particularly synchronous motors.[78] The increase in forecast error may lead to increased frequency deviations within the 5-minute dispatch interval and subsequently trigger the need for additional volumes of regulation services. This additional procurement of regulation services could be avoided if the frequency was held more closely to 50 Hz in the first place enabling improved accuracy in forecasting system demand.
  - Measurement errors may contribute to small ongoing errors in local metering and billing.
- Power quality

78 The variation of demand due to a change in frequency is known as load relief. When the frequency falls, synchronous motors, such as pumps and compressors, connected to the power system slow down and consume less power providing a net reduction in system load. Conversely, if the frequency is increased, the demand for power will be seen to increase.

Greater frequency variation may impact power quality through the sub-optimal operation of network and plant power control equipment that are designed to operate accurately when the power system frequency is close to 50Hz. This may particularly impact the effective and efficient operation of harmonic filters which are designed to reduce distortion of the voltage waveform due to high frequency harmonic fluctuations.

3.2.1 Disincentives in the NER to the provision of PFR

Dr Sokolowski's rule change request, *Primary frequency response requirement,* also identifies aspects of the NER that may be interpreted as providing a disincentive to the provision of PFR, noting:[79]

> generators currently have an incentive (if they do not wish to participate in the frequency control ancillary services (FCAS) market) of detuning their governor control systems to be non-responsive to frequency changes, so as to follow their dispatch targets and avoid disturbance to their internal processes.

The issue of prioritisation of strict compliance with dispatch instructions is also raised by AEMO in its rule change request, *Removal of disincentives to the provision of primary frequency response.* This issue is discussed further in section 3.3.2.

QUESTION 2: ISSUES RAISED BY DR SOKOLOWSKI IN HIS RULE CHANGE REQUEST, *PRIMARY FREQUENCY RESPONSE REQUIREMENT*

- What are stakeholders views on the issues raised by Dr Sokolowski in his rule change request, *Primary frequency response requirement*?
- Are there any other related issues or concerns that stakeholders have in relation to frequency control during normal operation and following contingency events?

3.3 AEMO — Removal of disincentives to the provision of primary frequency response

AEMO's rule change request, *Removal of disincentives to primary frequency response*, also raises for consideration certain aspects of the NER that may be interpreted as providing a disincentive to the provision of PFR.

AEMO identifies a need to clarify aspects of the NER that have been interpreted by some stakeholders as providing a disincentive to the provision of PFR. These disincentives to the provision of PFR include:[80]

- Certain aspects of the arrangements for the allocation of costs associated with the provision of regulation services to those that contribute to the need for those services as

79 Dr Sokolowski, *Primary frequency response requirement* — rule change request, 30 May 2019, p.8.

80 AEMO, *Removal of disincentives to primary frequency response*,- Electricity rule change proposal, 1 July 2019, pp. 14-25.

set out in clause 3.15.6A(k)(5)(i) and (7)(i) of the NER. This concept is conventionally known as 'causer pays'.

- A focus by generators on prioritising strict compliance with dispatch instructions, in accordance with cl 4.9.8(a) of the NER, instead of operating their plant in a frequency response mode and providing PFR.
- A perception that NER cl S5.2.5.11(i)(4) requires Generators to "turn off" or counteract their generating system's frequency responsiveness when they are not enabled to provide a Frequency control ancillary service (FCAS).

3.3.1 Allocation of regulation service costs — causer pays

AEMO's rule change request identifies that the existing arrangements in the NER do not explicitly state that a Market participant who operates its plant in a frequency response mode will not be attributed regulation FCAS costs. As a result, AEMO notes that Generators with scheduled and semi-scheduled generation may be operating their plant in a way that attempts to follow their dispatch targets at a uniform rate such that they are more likely to avoid a regulation FCAS cost allocation.[81]

Current Arrangements

AEMO´s regulation FCAS contribution factor procedure ('causer pays') is the mechanism by which AEMO recovers the cost of regulation FCAS from Market Participants. Regulation services costs are allocated to Market Generators and Loads on the basis of their contribution factors calculated over a period of a month. These factors reflect the degree to which the generators actual output or, in the case of a scheduled load, their actual demand, differ from the targets assigned by the NEM dispatch engine (NEMDE).

Under this procedure, a positive contribution factor represents a generation portfolio that, on aggregate, helped to manage disturbances in power system frequency, while a negative contribution factor denotes a generation portfolio that, on aggregate, contributed to deviations in power system frequency. A positive net contribution factor indicates a generator will not be allocated a portion of the costs of regulation FCAS.

The NER sets out principles for the determination of contribution factors for the allocation of costs associated with regulation services in Cl 3.16.6(k). These principles include that:

(5) a *Registered Participant* which has classified a *scheduled generating unit*, *scheduled load*, *ancillary service generating unit* or *ancillary service load* (called a **Scheduled Participant**) will not be assessed as contributing to the deviation in the *frequency* of the *power system* if within a *dispatch interval*:

(c) the Scheduled Participant is not *enabled* to provide a *market ancillary service*, but responds to a need for *regulation services* in a way which tends to reduce the aggregate deviation;

81 AEMO, *Removal of disincentives to primary frequency response*,- Electricity rule change proposal, 1 July 2019, p. 25.

This means that a generator that assists with frequency control in such a way that reduces the need for regulation services should not be penalised for providing such a frequency response.

Identified Issue

AEMO's rule change request identifies that, under the existing arrangements, some generators prefer to remove or detune their responsiveness to frequency to reduce the risk of being allocated costs through the causer pays process. This behaviour is supported by clause 3.15.6A(k)(5)(i), which states that a scheduled participant will not be assessed as contributing to the need for regulating services, and therefore face an allocation for the related costs of regulation services, if:

> the Scheduled Participant achieves its dispatch target at a uniform rate;

3.3.2 Prioritisation of compliance with dispatch instructions

AEMO's rule change request identifies that Generators are altering their frequency response deadband on their generation plant in order to more closely follow their dispatch instructions and decrease the risk that they may be found to be in breach of the requirement in the NER to comply with dispatch instructions.[82]

Current Arrangements

The NER contemplate that a generating unit may be operated in either a frequency responsive mode or in a mode that is unresponsive to frequency. The only reasons for which a plant is allowed under the NER to send out energy are detailed in cl 4.9.4(a) of the NER and include an allowance to send out energy both in accordance with a dispatch instruction and as a consequence of operating in a frequency responsive mode:

> 4.9.4 A *Scheduled Generator* or *Semi-Scheduled Generator* (as the case may be) must not, unless in the *Generator's* reasonable opinion, public safety would otherwise be threatened, or there would be a material risk of damaging equipment or the environment:
>
> (a) send out any *energy* from the *generating unit*, except:
>
> (1) in accordance with a *dispatch instruction*;
>
> (4) in the case of a *scheduled generating unit*:
>
> (ii) as a consequence of operation of the *generating unit's* automatic *frequency response mode* to *power system* conditions;

Additionally, cl 4.9.8(a) of the NER is an absolute obligation that:

> a registered participant must comply with a dispatch instruction given to it by AEMO unless to do so would, in the registered participant's reasonable opinion, be a hazard

82 Ibid.

to public safety or materially risk damaging equipment.

This clause applies to all registered participants. That is, not just scheduled generators but scheduled loads and scheduled network service providers. This clause is a civil penalty provision to reflect the significance of compliance.

The AEMC's views on compliance with clause 4.9.8(a) of the NER were set out in detail in the final determination on Snowy Hydro's rule change request on *Compliance with dispatch instructions*. The Commission was clear in its determination that compliance with this clause is vital both for the maximisation of the NEM spot market and FCAS market outcomes, but also for system security.[83]

The reality of the physics of the system however, is that a generator is unlikely to ever hit its target precisely. The actions of its governor (if it is in frequency response mode) can mean that the output of a generating unit may move away from its dispatch target consistent with its frequency response settings. Fluctuations away from a participant's dispatch target in response to frequency deviations are likely to be minor and can be distinguished from any deliberate action on the part of the registered participant.

In these circumstances, the AER's *Compliance and enforcement statement of approach* would suggest that the AER will not take action against generators whose governors are responding in the way they are supposed to in compliance with their performance standards.[84]

The NER also require that a market participant request and obtain AEMO approval prior to changing the frequency response mode and frequency control settings for its generating units.[85]

Identified Issue

AEMO's rule change request seeks to clarify in the NER that strict compliance with dispatch instructions should not take priority over provision of frequency response to help control system frequency.

3.3.3 Operating in frequency response mode

AEMO's rule change request identifies that a recent change to the NER made as part of the *Generator technical performance standards rule 2018*, may be compounding the perception by some Generators that the NER be interpreted as suggesting that a generator need not operate in a frequency response mode unless it is enabled to provide FCAS through the markets for ancillary services.[86]

Current Arrangements

To gain access to the network, generators must meet the access standards set out in schedule 5.2 of the NER, and in relation to frequency, S5.2.5.11(c) of the NER. The minimum

83 AEMC, *Compliance with dispatch instructions* — Rule determination, ERC0187, 5 May 2016, p.ii.

84 See: https://www.aer.gov.au/publications/corporate-documents/aer-compliance-and-enforcement-statement-of-approach

85 NER Clause 4.9.4(e)

86 Ibid., pp. 25-26

access standard in relation to frequency requires that any generator must have the capability to operate in a mode that responds to frequency. However, generators are not required to operate in a frequency response mode in order to connect to the power system. Additionally, a generator will be at least expected to operate such that it does not materially exacerbate changes in system frequency.

Operating in a frequency responsive mode once connected is at a generator's discretion, except when a generator elects to participate in a contingency frequency control ancillary service (FCAS) market. This requirement is set out in cl S5.2.5.11(i):

> (4) a *generating system* is required to operate in *frequency response mode* only when it is enabled for the provision of a relevant *market ancillary service*;

The Commission's final determination for the *Generator technical performance standards rule 2018*, included the following commentary in relation to this clause:[87]

> The final rule should [...] not be read to in any way preclude or prevent generators from electing to operate their generating systems in frequency response mode at times other than when they are enabled to provide FCAS.

As discussed above, a scheduled or semi-scheduled generator must not change the frequency response mode of a scheduled generating unit without the prior approval of AEMO.[88]

Identified issue

AEMO's rule change request identifies that some generators interpret clause S5.2.5.11(i)(4) of the NER as supporting them to turn off or counteract their plants responsiveness to frequency unless they are enabled for the provision of FCAS.

QUESTION 3: ISSUES RAISED BY AEMO IN ITS RULE CHANGE REQUEST, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*

(a) What are stakeholders views on the issues raised by the AEMO in its rule change request, *Removal of disincentives to primary frequency response*?

(b) Are there any other related issues or disincentives in the NER to the provision of PFR, that the AEMC should consider?

87 AEMC, *Generator technical performance standards rule 2018* — Final determination, 27 September 2018, p.59.

88 NER Clause 4.9.4(e)

4 PROPOSED SOLUTIONS

AEMO and Dr Sokolowski have proposed a number of changes to the NER that are intended to address the identified issues and improve frequency control in the NEM. For the purpose of facilitating stakeholder consultation, these solutions can be grouped into three broad categories of proposed changes to the NER:

- The introduction of a requirement in the NER for scheduled and semi-scheduled generating plant to be sensitive to locally measured frequency and respond in a way that helps correct a frequency deviation away from 50 Hz. A description of the characteristics of the mandatory PFR requirements proposed by AEMO and Dr Sokolowski is provided in section 4.1.
- The removal of disincentives that exist in the NER toward the voluntary provision of PFR — discussed in section 4.2.
- Other suggested changes to the NER proposed by Dr Sokolowski — discussed in section 4.3

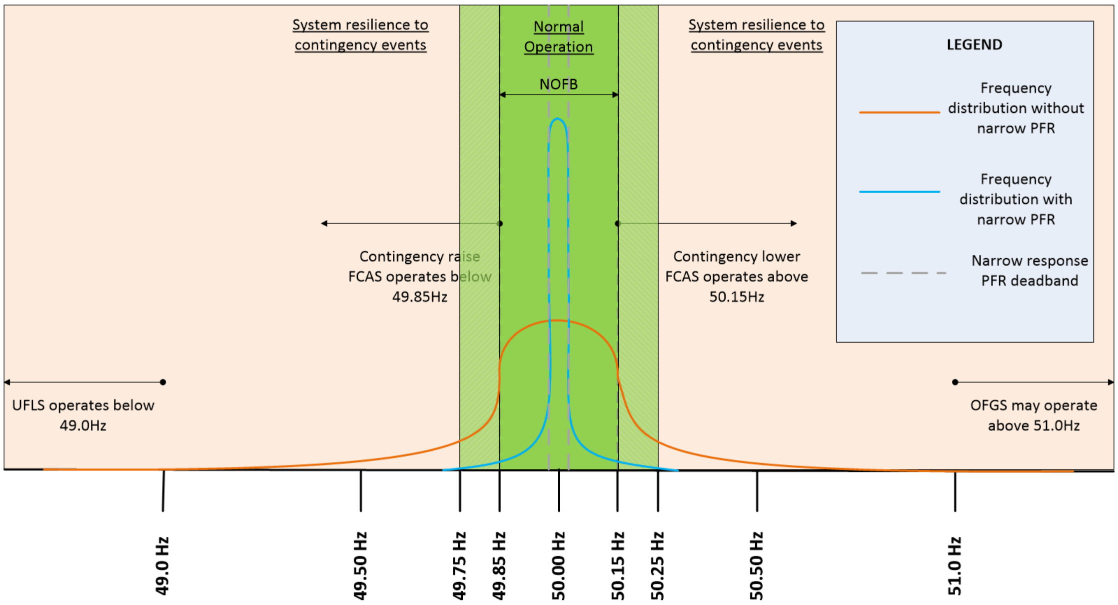
In addition to the solutions proposed by the rule proponents, the Commission considers that the policy development undertaken by the AEMC during the *Frequency control frameworks review* provides a number of potential solutions for improving frequency performance in the NEM. The relevant policy options developed through the *Frequency control frameworks review* are described in section 4.4.

4.1 Proposals for mandatory PFR

Both AEMO and Dr Sokolowski have requested changes to the NER to include a mandatory requirement for all capable scheduled and semi-scheduled generating plant to be operated such that they are responsive to changes in the locally measured power system frequency. While the specifics of each of the proposed rules are different, the objectives of this element of the rule change requests are largely aligned. The objectives for AEMO's rule change request, *Mandatory primary frequency response*, are summarised in section 1.1.1. The objectives of Dr Sokolowski's rule change request, Primary frequency response requirement are summarised in section 1.1.3.

The size of a frequency deviation that triggers an active power response is known as the frequency response, or governor, deadband. The frequency response deadband is an important operational variable that impacts both the frequency performance of the power system and the frequency response duty of the market participant's plant. Figure 4.1 displays a stylised representation of the relationship between the aggregate system frequency response deadband and the power system frequency distribution. When more of the generation fleet is responsive to frequency deviations within a narrow range either side of 50Hz, the power system frequency will be more tightly held close to 50Hz.

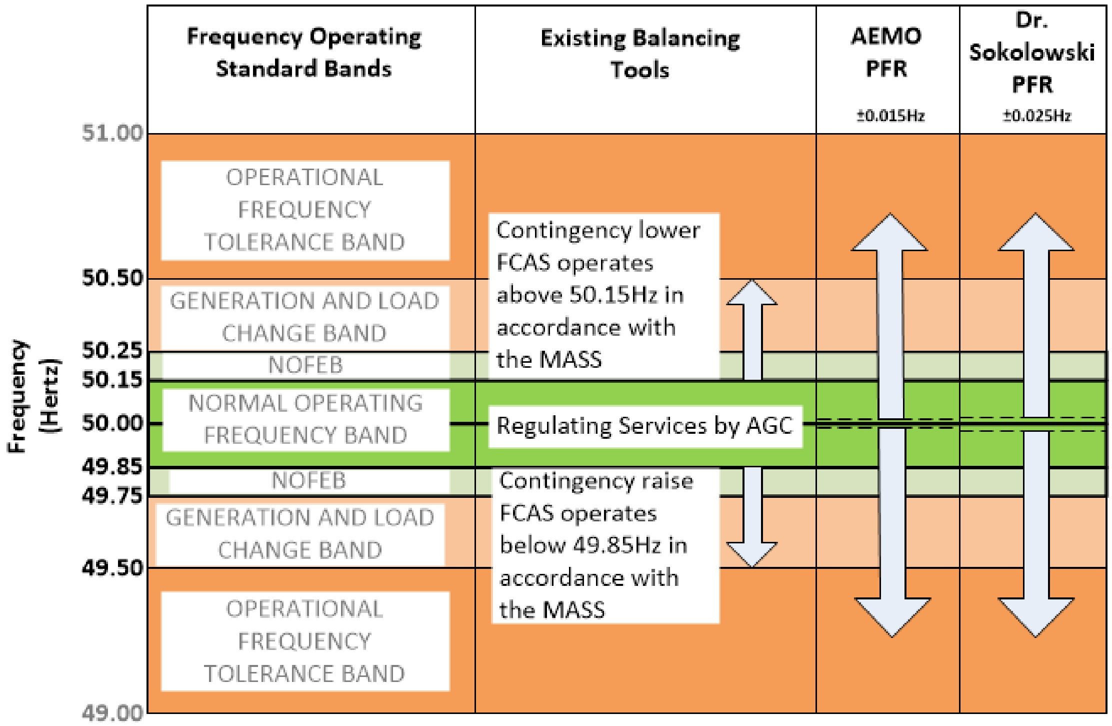
Figure 4.1: Frequency response deadbands and system frequency distribution



Source: AEMC

Figure 4.2 shows the frequency response deadbands included in AEMO and Dr Sokolowski's proposed PFR requirements.

Figure 4.2: **Existing frequency control tools and mandatory PFR requirements proposed by the rule change request proponents**



Source: AEMC

What frequency response deadband is required for effective frequency control in the NEM?

In its *Mandatory primary frequency response* rule change request, AEMO suggests that effective control and resilience of the power system would be achieved with a narrow response deadband. AEMO suggests that the allowable deadband be set at +-0.015Hz, which would align power system outcomes in the NEM with standard international practice and provide a stable basis for the ongoing transformation of the generation mix in the NEM.[89]

In particular, AEMO considers that a narrow response deadband would:

- Result in the most stable control of frequency under normal operating conditions and would reduce the amplitude of the observed ongoing oscillations in NEM frequency to the lowest practicable level.
- Maximise the resilience of the NEM to frequency disturbances by minimising the frequency deviation caused by any given power system disturbance, which would provide the best opportunity of maintaining stable operation of the power system.

89 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p. 46

AEMO considers that a wide deadband at +-0.5Hz would

- Allow frequency to change by half the level required for UFLS or OFGS to be triggered before any response is initiated from generation outside the FCAS markets, significantly reducing the time and margin available for correction of the frequency deviation before these emergency responses come into play. [90]
- Provide no additional guidance or insight for modelling and analysis on expected responses from generation, and the power system overall, for events where frequency remained within +0.500 Hz for 'Generation Events' or 'Load Events' (as specified in the FOS), which covers the vast majority of disturbances. [91]
- Setting a mandatory PFR deadband wider than the NOFB would signal to Generators currently providing PFR outside of FCAS markets that they could, and perhaps should, further widen their existing PFR deadband. This would likely have the perverse outcome of reducing the PFR provided in response to all but the most extreme disturbances, making all disturbances more difficult to recover from. [92]

AEMO considers that a deadband at the edges of the NOFB would continue to treat frequency control under normal operating conditions and following disturbances as separate matters. It would:

- Go some way towards improving the resilience and predictability of power system performance by providing a frequency response when a significant power system disturbance occurs
- Have no impact on frequency control under normal operating conditions. The NEM would remain an outlier in the international context at a critical time when the NEM is leading the rate of integration of inverter-connected generation.

The following sections describe the key elements of the mandatory PFR requirements proposed by AEMO and Dr Sokolowski, including how they are proposed to be implemented in the NER.

4.1.1 AEMO's proposed mandatory PFR requirement

AEMO's rule change request, *Mandatory primary frequency response*, proposes the introduction of a PFR requirement. AEMO's proposed rule includes changes to clause 4.4.2 of the NER to require all scheduled and semi-scheduled generating units and generating systems to be responsive to frequency outside of a defined frequency deadband. Under AEMO's proposed rule, the maximum allowable frequency response deadband, along with other technical characteristics would be determined by AEMO and specified in a new document, the *Primary Frequency Response Requirements* (PFRR) which it would prepare in accordance with the rules consultation process.[93]

90 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p. 48

91 Ibid.

92 Ibid.

93 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, pp. 44-45.

The parts of AEMO's proposed rule that set out the proposed PFR requirement for Generators, as a mark-up of clause 4.4.2, are:

> **(b)** each ~~Each~~ *Generator* must ensure ~~that~~ all ~~of~~ its *generating units* meet the technical requirements for *frequency*~~frequency~~ control in clause S5.2.5.11;
>
> (c) each *Scheduled Generator* and *Semi-Scheduled Generator* must operate its *generating system* in accordance with the *Primary Frequency Response Requirements* as applicable to that *generating system;*

AEMO's rule change request provides an overview of the technical performance parameters that it intends to specify in the PFRR, including:[94]

- A maximum frequency response **deadband** of ±0.015Hz
- A maximum **droop** setting of 5% (which corresponds to an active power increase of 10% for a sustained frequency deviation of 0.25Hz beyond the frequency response deadband)
- The **speed of response** should result in at least a 5% change in output within 10 seconds
- PFR should be **sustained** to the extent that plant is capable of doing so within safety and stability limits.
- A Generator's control systems should **not counteract** the delivery of PFR to reduce it to a level that is below what the plant could otherwise deliver, subject to safety and stability limits.

AEMO proposes that the PFRR document will also set out the following criteria related to PFR:[95]

- the process by which AEMO would approve a variation or exemption from a performance requirement related to the provision of PFR
- the details of any information to be provided by a Generator and audits or tests that may be conducted to verify compliance with the requirement.

AEMO's rule change request indicates that it does not intend to prescribe requirements for the following technical criteria associated with the provision of PFR:[96]

- **Headroom** — there is no proposal for a headroom or reserve requirement — any generating plant that is unable to raise output in response to falling frequency, or lower output in response to rising frequency due to a lack of available headroom, will not be deemed as non-compliant.
- **Minimum droop** — there is no proposal for a minimum droop requirement.

Further detail on the content of AEMO's proposed PFRR is set out in Box 3 below.

94 Ibid.
95 AEMO, *Primary frequency response requirements* — draft, August 2019, pp. 6-8
96 Ibid.

Compensation arrangements for plant upgrades

AEMO's proposed rule includes provisions for transitional rules under which a Generator may submit a claim to AEMO for the reimbursement of costs associated with changes to its plant to provide PFR in accordance with the proposed PFR requirement.

AEMO proposes that the introduction of the PFR requirement consistent with its proposed rule be determined as a '*declared NEM project*' and that any expenditure incurred as a result of this project be recovered by AEMO through participant fees in accordance with the NER.[97]

Proposed implementation of the PFR requirement

The correction of a frequency deviation in the power system requires an active power injection or withdrawal that is proportional to the change in active power that caused the deviation. As such, AEMO acknowledges that the implementation of the PFR requirement would require careful coordination and timing to facilitate a prompt transition without exposing generators who are the first to implement change to greater risks in providing PFR. AEMO therefore proposes that all scheduled and semi-scheduled generators with a nameplate rating of greater than 200MW would be the first to be required to adjust their plant control settings. AEMO believes that this would result in a material improvement in frequency stability due to this tranche of generators representing the majority of generation capacity in the NEM. The remaining plant with nameplate capacities less than 200MW will be required to adjust their plant once the first tranche of generators is complete.[98]

AEMO's PFRR obliges affected generators to self-assess the ability of their plant to meet the PFR requirements.[99]For generators of nameplate capacities greater than 200MW, the submission to AEMO of the results of this self-assessment is due within 60 business days from the date of commencement of the PFRR. For generators of lower nameplate capacities, the submission is due within 120 business days. AEMO will respond within 20 business days of receiving results from a generator, unless further information from the generator is required.

AEMO will require all technically capable generators to adjust or modify their plant to provide PFR, provided the upfront costs of plant modification are reasonable in AEMO's opinion. If a plant does not meet the PFRR and AEMO determines further action is required by the plant to do so, AEMO will liaise directly with the plant to determine the details of the work to be completed. No works are to be commenced by any plant prior to AEMO agreement.[100]

AEMO's proposed transitional rules

AEMO proposes transitional rules that set out the obligation and responsibilities for the implementation of the proposed PFR requirement.[101] The key elements of AEMO's proposed transitional rules include that:

97 NER rule 2.11(b)(2)(iv)

98 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, pp. 44.

99 AEMO, *Primary frequency response requirements* — draft, August 2019, pp. 8-9

100 Ibid.

101 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, pp. 61-65.

- AEMO prepare an interim PFRR to apply from the commencement date of the rule.
- the Interim PFRR to specify the date by which generators must comply with the obligation, which may vary by plant type.
- a process for Generators to submit a claim for compensation associated with plant upgrades to become compliant with the PFRR.

BOX 3: AEMO'S DRAFT *PRIMARY FREQUENCY RESPONSE REQUIREMENTS*

AEMO's proposed rule, *Mandatory primary frequency response*, sets out a proposed governance arrangement where the NER would require AEMO to prepare the *Primary frequency response requirements* and that scheduled and semi-scheduled generators must operate their plant in accordance with the *Primary frequency response requirements*.

AEMO has prepared a draft of the *Primary frequency response requirements* (PFRR) to detail the technical requirements and application of the mandatory PFR requirement as proposed in their rule change request. The following is a summary of AEMO's draft PFRR.

Technical Requirements

AEMO describes the active power modulation that constitutes PFR and details the proposed parameters of the required response, including that:

- there is no requirement to maintain headroom for the provision of PFR,
- the maximum deadband outside of which generators must provide PFR is to be ±0.015Hz,
- the droop setting that dictates the amount of active power change for a change in frequency beyond the deadband, measured as a percentage of a Generator's maximum operating level, is to be less than or equal to 5%,
- the speed of response should be such that a 5% change in active power is achieved in no more than ten seconds,
- the response should be sustained until the power system frequency returns to within the deadband, subject to plant capability,
- a generator should not use plant controls to limit PFR if it can be safely and stably delivered, recognising a generator's operational ranges such as minimum and maximum operating levels,
- PFR must remain continuously enabled with consistent settings unless otherwise agreed with AEMO.

Application

The draft PFFR sets out a proposed process for Generators to demonstrate to AEMO their compliance with the technical requirements, including:

- The requirement and time frame for generators to conduct and submit to AEMO a self-assessment of technical capabilities to comply with the PFRR. For Generators with nameplate capacity greater than 200MW, this is to be completed within 60 business days from commencement of the PFRR. Other generators are allowed 120 business days.

- AEMO's ability to request further information within five days if it deems the information provided by a generator to be insufficient. Generators must provide the requested information within five days of the request.
- AEMO's response to Generator self-assessments, to be provided within 20 days of receipt. AEMO will acknowledge generators that meet the Technical Requirement or will liaise with the Generators that will need to modify their plant regarding control settings, scope of modification work and time frames.
- A prohibition to initiate any modifications of plant to meet the Technical Requirements prior to AEMO's response and agreement.
- Generators may apply for an extension of the specified due date to complete plant modifications. AEMO will consider and respond to such requests within 20 business days.
- Generators must apply to AEMO to make changes to their agreed control settings. AEMO will consider and respond to such requests within 20 business days.

Exemptions

AEMO recognises that some generators may not be inherently capable of providing PFR and so may need to seek exemption from the requirements stipulated in the PFRR. Therefore, the draft PFRR includes the following information on seeking exemptions and standing exemptions:

- A plant may be eligible for exemption from the PFRR if it cannot be modified, or requires significant augmentation, to provide PFR.
- A plant must submit its application for an exemption to AEMO, with reasons and supporting evidence, within the time frames stipulated above for a plant's self–assessment of technical capabilities.
- AEMO may request further information within ten days if it deems the information provided by a generator to be insufficient. Generators must provide the requested information within ten days of the request.
- Standing exemptions for the steam turbine components of CCGT plant and for plant when operating in synchronous condenser mode.

Testing and Modelling

Generators that make changes to their plant and plant control systems will be required by AEMO to undertake the appropriate tests to demonstrate compliance with the PFRR and any other relevant standards depending on the extent of the changes.

At a minimum, the draft PFRR states that any change to a *control system* or primary plant will require a step response stability test that tests the response of the plant to a step change in frequency of ±5%.

Any changes beyond plant load controllers will require the generator to test its plant in accordance with the requirements of AEMO's *GPS Compliance Assessment and R2 Model Validation Test Plan Template*.

Publication

The draft PFRR requires AEMO to publish and maintain a list of generating plant containing the details of their PFRR exemption or compliance status.

Compensation for implementation costs

AEMO outlines in the draft PFRR which plant are eligible for compensation and the process for generators to seek compensation:

- Generating plant that have an existing connection agreement and need to alter their plant to meet the Technical Requirements are eligible to recover the costs directly and reasonably incurred to modify the plant.
- AEMO provides examples of compensable and non-compensable costs.
- Generators must submit an application for compensation using the form in Appendix C of the PFRR
- AEMO details the supporting evidence required for compensation of implementation costs and may request further information if necessary.
- AEMO will advise Generators of the outcome of their application within 30 business days. If AEMO determines the costs of modifying a plant to be uneconomic, AEMO may grant the plant exemption from the PFRR.
- A generator may agree or dispute the outcome of their application for compensation.
- AEMO will pay the compensation agreed or awarded to an Affected Generator within 20 business days of receipt of the relevant documentation.

Submission Forms

AEMO's draft PFRR includes the following proposed appendices:

- a form for a Generator’s self-assessment of technical capability.
- a form for a Generator to apply for an exemption from the PFRR.
- a form for a Generator to apply for compensation of implementation costs.

Source: AEMO, *Primary frequency response requirements* — Draft, 16 August 2019

Note: 1. The draft *Primary frequency response requirements* was provided to the AEMC by AEMO as an attachment to its rule change request, *Mandatory primary frequency response*.

Stakeholder Consultation

The Commission is interested in stakeholders’ views on whether the changes that would be required of their plant could be practically implemented in this time and whether stakeholders have any concerns with AEMO's suggested approach for implementing a PFR requirement.

> **QUESTION 4: CAPABILITY OF GENERATION PLANT AND THE IMPLEMENTATION PROCESS FOR AEMO'S PROPOSED MANDATORY PFR REQUIREMENT**
>
> In relation to AEMO's rule change request, *Mandatory primary frequency response*, and the draft PFRR:
>
> - For stakeholders who own and operate scheduled or semi-scheduled generation plant: How easily can your plant meet the requirements of AEMO's draft PFRR? What, if any, adjustments or investments would need to be made and what are the expected costs?
> - Do stakeholder agree with AEMO's proposed allocation of requirements between the NER and the PFRR under its proposed rule?
> - Do stakeholders consider the implementation time frames suggested by AEMO in its draft PFRR to be appropriate? In relation to AEMO proposed self assessment process, is it appropriate for generators >200MW to provide AEMO with a self assessment within 60 business days and generators <200MW to provide AEMO with a self assessment within 120 business days?
> - Do stakeholders consider there to be a more appropriate approach to coordinating the implementation of a PFR requirement across the generation fleet?

AEMO's expected costs and benefits of the proposed rule change

AEMO considers that there are substantial costs associated with not making the proposed rule due to the ongoing decline to the power system's resilience. AEMO expects that the costs to generators of complying with the requirements of the proposed rule are likely to be minimal in most cases and that the proposed rule is expected to increase the resilience of the power system and therefore lessen the risk that consumers incur costs associated with major power supply interruptions. Similarly, the rule should improve the economic efficiency of power system operation and planning. AEMO believes the proposed rule has merit as the indirect costs to consumers, such as those passed through by generators due to potential increases in operational costs, are expected to be small and are more than offset by the improvements to power system resilience, security and stability.[102]

Costs associated with the proposed rule:

AEMO believes there are substantial ongoing costs of poor frequency performance in the NEM. AEMO lists the costs of not addressing frequency performance in the NEM as arising from:[103]

- the economic impacts on consumers and market participants of major supply disturbances that would otherwise be avoided if the power system were more stable
- inefficiencies in generation and network asset operation
- potential need for additional contingency and regulation FCAS

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102 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, August 2019, pp. 55-59

103 Ibid, p. 55.

AEMO identifies that implementing the rule may result in upfront and ongoing costs to generators, including:[104]

- costs of changing plant control systems to provide PFR
- direct costs of the provision of PFR, including wear and tear and additional fuel costs, for generators not currently providing PFR

Generators may also experience a potential decrease in generator revenue from contingency FCAS markets due to increased supply pushing down FCAS prices.

AEMO's proposed rule includes a mechanism for generators to recover the cost of modification where the cost is material. However, AEMO expects the upfront costs to be minor in most cases. Similarly, AEMO believes the costs of provision of PFR to be minimised by the proposed rule and expects wear and tear costs to ultimately be less than currently experienced once frequency is well controlled.

AEMO does not expect the proposed rule to materially increase costs to consumers.

Benefits to consumers of the proposed rule

AEMO expects that its proposed rule will increase power system frequency stability, thereby providing greater system security and resilience to major disturbances. The proposed rule should achieve this by:

- reducing the magnitude of ongoing, poorly controlled frequency oscillations
- increasing the frequency control 'buffer' beyond contingency FCAS for additional system resilience to large frequency disturbances
- ensuring a predictable response from each generator, improving AEMO's ability to design emergency control schemes
- reducing the reliance and expected incidence of UFLS and OFGS

Increased security and resilience from improved frequency control would provide benefits to consumers relating to the avoidance of costs associated with load interruptions and excess procurement of frequency control services.[105]

AEMO's estimate of the cost-benefit trade-off

AEMO believes that the proposed rule is in the best interests of consumers and in line with the NEO. AEMO considers that the proposed rule will provide it with the necessary tools to improve frequency performance and therefore avoid the economic and technical consequences of poor frequency control. AEMO considers that the proposed rule will also increase the efficiency of power system operation and planning with minimal to no costs to consumers.[106]

104 Ibid, pp. 55-56.
105 Ibid, pp. 56-58.
106 Ibid, pp. 58.

AEMO asserts that the proposed rule is a proportional response to the issue and that any costs incurred by generators to comply with the proposed rule would not exceed the immediate and long-term benefits to be gained by consumers.

> ### QUESTION 5: AEMO'S EXPECTED COSTS AND BENEFITS FOR ITS PROPOSED RULE, *MANDATORY PRIMARY FREQUENCY RESPONSE*
>
> In relation to AEMO's proposed rule, *Mandatory Primary frequency response* :
>
> - Do stakeholders agree with AEMO's characterisation of the costs and benefits associated with its proposed rule?
> - What do stakeholders consider to be the immediate and ongoing costs of providing PFR and being compliant with the proposed rules?
> - Is AEMO's proposed compensation arrangements for plant upgrades necessary and appropriate?
> - Do stakeholders consider the proposed rules to be a cost effective solution to the frequency control issues identified by the proponents?

4.1.2 Dr Sokolowski's proposed mandatory PFR requirement

Dr Sokolowski proposes to introduce a mandatory PFR requirement that is implemented through changes to Schedule 5.2 of the NER. Schedule 5.2 of the NER sets out the technical performance requirements that a generating system must satisfy as a condition of connection to the power system.[107]

Dr Sokolowski's proposed rule includes new sub paragraphs (g) and (h) under cl S5.2.5.11 which are set out as mandatory requirements. The proposed new rules clauses are:

> (g) Each synchronous generating unit must have enabled and responsive speed governor systems with deadbands no greater than 50 mHz (to avoid doubt +25 mHz to — 25 mHz) providing primary frequency control and maintaining nominal rotational speed of the generating unit in steady state conditions and contribute to system response for contingency events.
>
> (h) Asynchronous generating systems must have enabled frequency droop control with deadbands no greater than 50 mHz (to avoid doubt +25 mHz to — 25 mHz) providing frequency response in steady state conditions and contribute to the system response for contingency events.

Dr Sokolowski's expected costs and benefits of the proposed rule change

Dr Sokolowski, in his *Primary frequency control requirement* rule change request, considers that poor frequency control in the NEM results in a direct economic impact on market participants and can also have wider negative effects on the economy. Similar to AEMO's

107 Dr Sokolowski, *Primary frequency response requirement* — Electricity rule change proposal, 30 May 2019, pp.17-24.

position, the rule change request includes the argument that improvements in system security and reliability would be greatly beneficial to all market participants and consumers due to the operational costs of poor frequency performance and the potential economic impacts of load interruption. Dr Sokolowski considers the proposed rule is in the long-term interests of consumers under the NEO as it aims to ensure that the power system is secure and that investment in and operation of electricity services and assets is efficient.[108]

Costs associated with the proposed rule

Dr Sokolowski places emphasis on the potential costs of poor frequency control and limited system resilience. As identified by AEMO in its *Mandatory primary frequency response* rule change request, Dr Sokolowski also acknowledges that no action to improve frequency control would continue to impose costs on consumers associated with:[109]

- load interruptions following large frequency disturbances
- wear and tear
- inefficient operation of generator and transmission networks

In addition, the rule change request identifies some other potential costs of frequency volatility:

- Frequency measurement errors could result in inefficient dispatch of energy and energy billing
- Increased risk of tripping interconnectors and islanding regions where the economic benefits of interregional flows are foregone

Dr Sokolowksi also notes that black system events, which are more likely if frequency remains uncontrolled, also have a wide-reaching impact on the economy outside of the NEM.

Benefits to consumers of the proposed rule

Dr Sokolowski considers that the proposed rule will increase power system security, resulting in a number of benefits to consumers including:[110]

- allowing consumers to avoid the costs of poor frequency performance as set out above
- fewer safety hazards for plant operators due to less risk of equipment failure
- more efficient investment in and use of electricity services with respect to reliability and security of the supply of electricity

Dr Sokolowski's estimate of the cost-benefit trade-off

Dr Sokolowski considers that the proposed rule contributes to the NEO through improvements in the price, reliability and security of the supply of electricity, as well as the reliability, safety and security of the national electricity system. These expected benefits are in the long-term interests of consumers. The rule change request assumes that the economic and technical risks of not addressing power system frequency performance in the NEM

108 Dr Sokolowski, *Primary frequency response requirement* — Electricity rule change proposal, May 2019, pp. 8-10

109 Ibid, pp. 4-5

110 Ibid, pp. 8-9

outweigh the costs of implementing the rule change, with Dr Sokolowski stating the rule would result in a net benefit to all market participants and consumers.[111]

> QUESTION 6: DR SOKOLOWSKI'S EXPECTED COSTS AND BENEFITS FOR HIS PROPOSED RULE, *PRIMARY FREQUENCY RESPONSE REQUIREMENTS*
>
> In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:
>
> - Do stakeholders agree with Dr Sokolowski's characterisation of the costs and benefits associated with his proposed rule?
> - What do stakeholders consider to be the immediate and ongoing costs of providing PFR and being compliant with the proposed rules?
> - Do stakeholders consider the proposed rules to be a cost-effective solution to the frequency control issues identified by the proponent?

4.1.3 Limitation to the AEMC's rule making powers and accrued rights

There are some limitations on the AEMC's rule making powers that constrain the Commission's ability to make certain rules. The Commission does not have the power to make retroactive rules, that commence on a date before the rule is made and gazetted. [112] In addition, rules made by the Commission that have certain types of retrospective effect (retrospective rules) may be deemed invalid. That applies to rules that repeal or amend an existing rule in a manner that affects existing rights and liabilities in any of the ways described in paragraphs (a)-(e) of clause 33(1) of Schedule 2 to the National Electricity Law (NEL). These existing rights or liabilities are referred to as 'accrued rights'.

The issue of whether a rule to require mandatory PFR from existing generators in the NEM would affect the accrued rights of existing generators was raised by the Commission during the *Frequency control frameworks review*. In relation to this issue the Commission noted that it:[113]

> would need to consider the most appropriate way to implement a mandatory requirement for the provision of primary frequency control and the impact of any mandatory requirement on the accrued rights of generators with pre-existing connection agreements.

AEMO's position on the accrued rights in relation to its rule change request, *Mandatory primary frequency response*

The issue of accrued rights is also discussed in AEMO's rule change request, *Mandatory primary frequency response,* with respect to AEMO's proposed rule.

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111 Ibid.

112 Section 104 of the NEL provides that a rule made commences operation on the day the relevant notice is published in the South Australian Government Gazette or on any day after that day, provided for in the relevant notice or the rule.

113 AEMC, *Frequency control frameworks review* — Issue paper, 7 November 2017, p.69.

AEMO's view is that its proposed rule will not impact any accrued right as considered under Schedule 2 clause 33(1) of the NEL.

With respect to the potential for its proposed rule to impact any accrued right in relation to an existing Generator connection agreement, AEMO outlines the following:[114]

> The content of connection agreements between Generators and Network Service Providers is prescribed by the NER, notably Schedule 5.6, which includes, among other things, the performance standards that apply to the connected generating system.
>
> Performance standards are based on the access standards in Schedule 5.2 of the NER. Frequency response requirements in the access standards (clause S5.2.5.11) have changed to some extent over time, but have always required generating systems to be capable of frequency response at least from the outer limits of the NOFB. Currently, clause S5.2.5.11(c)(2) requires all generating systems to have automatic PFR capability. The proposed requirements of this rule have been drafted to remain consistent with these required capabilities. It is the changes to clause 4.4.2 of the NER, rather than the performance standards themselves, that have modified and ultimately removed the obligation to operate in frequency response mode unless enabled for FCAS. The effect of the proposed rule would be to reinstate that obligation.
>
> AEMO contends that the absence of an obligation cannot be an accrued right, and the imposition of a forward-looking obligation cannot affect a right or liability as it applied before the rule was made.

AEMO also contends that the loss of an ongoing entitlement to be paid for providing a frequency response through the market arrangements for FCAS does not constitute an impact on an accrued right. [115]

In relation to concerns in respect of the cost of modifications required to comply with the proposed PFR requirement, AEMO proposes to compensate relevant Generators for any associated material capital costs.[116]

4.2 Proposals to address disincentives to PFR

Through their respective rule change requests, both AEMO and Dr Sokolowski have identified a number of elements of the NER that are perceived to present disincentives to the provision of PFR. The proposed changes to the NER put forward by AEMO and Dr Sokolowski in relation to disincentives to PFR are described in the following sections.

- Section 4.2.1 describes AEMO's proposed rule changes to address disincentives to PFR
- Section 4.2.2 describes Dr Sokolowski's proposed rule changes to address disincentives to PFR.

114 AEMO, *Mandatory Primary frequency response* — Electricity rule change proposal, 16 August 2019, p.54.

115 Ibid.

116 Ibid.

4.2.1 AEMO's proposed rule changes to address disincentives to PFR

AEMO's rule change request, *Removal of disincentives to primary frequency response*, proposes changes to the NER to clarify the existing requirements and remove disincentives to the provision of PFR by market participants in the NEM. AEMO sets out that the objectives of the proposed rule is to:[117]

- arrest the deterioration of frequency control under normal operating conditions as soon as possible
- facilitate the voluntary provision, or increased delivery, of PFR within the NOFB
- reduce the likelihood of generators changing their frequency response mode without AEMO approval.

AEMO's proposed rule can be broken up into the following components, each of which address one of the identified disincentives in the NER to the voluntary provision of PFR and the operation of plant in a frequency response mode.

- Changes to the NER clause 3.15.6A in relation to the allocation of regulation service costs to market participants through AEMO's causer pays procedure
- Changes to the NER clause 4.9.4 and cl 4.9.8 in relation to the interaction of compliance with dispatch instructions and operation of plant in a frequency response mode
- Changes to the NER cl S5.2.5.11 in relation to the operation of generation in a frequency response mode. This includes a proposal to clarify that operating in a frequency response mode does not constitute a breach of a generator's requirement to comply with its dispatch instructions.

AEMO's rule change request, *Mandatory primary frequency response*, also includes the same requested changes to NER clause 4.9.4, cl 4.9.8. In addition, the proposed *Mandatory primary frequency response* rule would delete clause S5.2.511 as it is inconsistent with AEMO's proposed mandatory PFR requirement. AEMO believes that the changes to clause 4.94, 4.98 and S5.2.5.11, as noted above, are required as a minimum to support the proposed mandatory PFR requirement.[118]

Allocation of regulation service costs — causer pays

AEMO's proposed rule, *Removal of disincentives to primary frequency response*, includes change to parts of chapter 3 of the NER that set out the principles for AEMO's development of a procedure for determining contribution factors for the allocation of the costs of regulation services to market participants. The proposed changes are intended to remove the incentive for a generator to track its dispatch target at a uniform rate and include provisions to allow for a market participant that operates its plant in a frequency response mode to be excluded from the allocation of regulation FCAS costs.[119] The rule change request includes the following proposed changes:

117 AEMO, *Removal of disincentives to the provision of primary frequency response* — Electricity rule change proposal, 1 July 2019, pp. 26-27.

118 AEMO, *Mandatory primary frequency response* requirement — Electricity rule change proposal, 16 August 2019, p.45.

119 AEMO, *Removal of disincentives to primary frequency response under normal operating* conditions — Electricity rule change proposal, 1 July 2019, pp. 26-27.

- For the purposes of determining whether or not a market participant will be assessed as contributing to the deviation in the frequency of the power system, Cl 3.15.6A (k)(7), which relates to semi-scheduled generators, is deleted and Cl 3.15.6A (k)(5) is revised to cover any Market Participant.[120]
- The criteria under which a Market Participant will be not be assessed as contributing to the deviation of the frequency of the power system are revised, including:
  - Cl 3.15.6A (k)(5)(i) is deleted such that a participant achieving its dispatch target at a uniform rate would not be automatic grounds for avoidance of an allocation of regulation service costs for a given dispatch interval.
  - Cl 3.15.6A (k)(5)(iii) is revised such that a Market Participant will not be allocated a share of the costs of regulation services, if it operates its plant in a frequency response mode in accordance with the settings in the Causer Pays procedure and responds to arrest the frequency deviation.
- New clause Cl 3.15.6A (nc) requires AEMO to maintain and publish on its website a list of plant being operated in a frequency response mode in accordance with Cl 3.15.6A (k)(5)(iii).

AEMO's Regulation FCAS Contribution Factor Procedure

AEMO have indicated that they will also soon commence a consultation process to amend the procedure for the allocation of Regulation FCAS costs, known as 'causer pays'.[121]

AEMO is proposing changes to the Causer Pays procedure to specify a frequency response deadband for the purposes of operating in a frequency response mode consistent with the proposed rule Cl 3.15.6A (k)(5)(iii). AEMO's intent is that frequency responsiveness would be voluntary and, if a Market Participant operates its plant with a frequency response band equal to, or less than, the band specified in the Regulation FCAS Contribution Factor Procedure, then it would not be exposed to an allocation of the costs of regulation services.

AEMO is proposing to specify a frequency response deadband of ±0.075 Hz either side of 50Hz for the first 6 months from publication of the amended Regulation FCAS Contribution Factor Procedure. Following on from that, AEMO is proposing a frequency response deadband of ±0.050 Hz either side of 50Hz which will apply from 6 months after publication of the amended Regulation FCAS Contribution Factor Procedure.

Stakeholders who wish to provide feedback on the specific settings for the deadband should do so through AEMO's consultation process for the Regulation FCAS contribution factor procedure.

AEMO have indicated that they will also soon commence a consultation process to amend the Market ancillary services specification (MASS). In the rule change request, AEMO have stated

120 A Market participant is defined in chapter 10 of the NER as: A person who is registered by AEMO as Market Generator, Market Customer, Market Small Generation Aggregator, Market Ancillary Service Provider or Market Network Service Provider under Chapter 2.

121 AEMO, *Removal of disincentives to primary frequency response under normal operating* conditions — Electricity rule change proposal, 1 July 2019, p. 41.

that the goal of this consultation is to address disincentives to market participants providing PFR within the NOFB.[122]

Frequency Response and compliance with dispatch instructions

AEMO's proposed rule includes changes to cl 4.9.4 and cl 4.9.8 to clearly acknowledge that it is expected and acceptable for generation output to vary from dispatch targets when providing PFR. The proposed changes are summarised below:[123]

- Under cl 4.9.4(a), sub-clause 4(ii) is deleted and a new sub-clause 3A is included to confirm that a scheduled or semi-scheduled generator may send out energy from a generating unit as a consequence of operating in a frequency response mode to help control system frequency.
- Under cl 4.9.8, a new sub-clause is added to confirm that a Scheduled or Semi-Scheduled Generator is not taken to have failed to comply with a dispatch instruction as a consequence of the operation of a generating unit in frequency response mode to help control system frequency.

AEMO's intent is that these proposed changes will remove stakeholder concerns around the provision of PFR resulting in non-compliance with dispatch targets.

Operating in a frequency response mode

AEMO's proposed rule includes changes to the general requirements for a connecting generator in relation to frequency control as set out in S5.2.5.11(i) of the NER. The proposed rule clarifies that generating systems <u>may</u> operate in frequency response mode at any time, but <u>must</u> operate in a frequency mode when enabled to provide a relevant market ancillary service. [124]

The drafting of S5.2.5.11(i) in AEMO's proposed rule also includes a new reference that this sub-clause is subject to cl 4.9.4(e). The intent of this is to reinforce the requirement in cl 4.9.4(e) that a Generator must not change the frequency response mode of a scheduled generating unit without the prior approval of AEMO.

QUESTION 7: AEMO'S PROPOSED RULE, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*

Allocation of regulation service costs — causer pays

- Does AEMO's proposed rule adequately address stakeholder concerns in relation to the risks and rewards associated with the voluntary provision of PFR?

122 AEMO, *Removal of disincentives to primary frequency response under normal operating* conditions — Electricity rule change proposal, 1 July 2019, p. 35.

123 AEMO, *Removal of disincentives to primary frequency response under normal operating* conditions — Electricity rule change proposal, 1 July 2019, p. 51.

124 AEMO, *Removal of disincentives to primary frequency response under normal operating* conditions — Electricity rule change proposal, 1 July 2019, p. 52.

- Do stakeholders envisage any unintended consequences as a result of the proposed rule change?
- Does the causer pays procedure contain any other potential barriers to the provision of PFR under normal operating conditions?

Frequency response and compliance with dispatch instructions

- What are stakeholders views on AEMO's proposed changes to clauses 4.9.4 and 4.9.8 of the NER to address disincentives to PFR relating to compliance with dispatch instructions?

Operating in a frequency response mode

- What are stakeholders views on AEMO's proposed rule to address disincentives to PFR related to the requirements for FCAS provision?
- Do stakeholders identify there to be any other sections of the NER that may restrict generators from operating in a frequency responsive mode and providing PFR

AEMO's expected costs and benefits of the proposed rule change

AEMO considers that the proposed rule to remove disincentives to the provision of PFR will contribute to addressing poor frequency performance in the NEM and will provide net benefits to consumers. While there are potential costs for generators to modify their plant to become frequency responsive, AEMO's proposed rule does not impose any obligations on generators to change their behaviour and therefore the costs to market participants would be incurred voluntarily. As generators are only likely to incur the costs of providing PFR if the benefit to the plant is greater, AEMO believes any additional PFR in the NEM as a result of the proposed rule should represent an overall net benefit for market participants and consumers.[125]

Costs associated with the proposed rule

AEMO believes there are substantial ongoing costs of poor frequency performance in the NEM and not making the proposed rule will continue the realisation of these costs. AEMO lists the costs of not addressing frequency performance in the NEM through this proposed rule as arising from:[126]

- the economic impacts on consumers and market participants of major supply disturbances that may otherwise be avoided if the power system were more stable
- inefficiencies in generation and network asset operation
- potential need for addition contingency and regulation FCAS

AEMO does not think the rule will result in additional costs to consumers. Instead, the proposed rule and subsequent changes to the causer pays procedure will mainly result in a

125 AEMO, *Removal of disincentives to primary frequency response during normal operation* — Electricity rule change proposal, July 2019, pp. 42-48.

126 Ibid, p. 42.

redistribution of costs from generators who provide PFR towards market customers and generators who do not provide PFR.[127]

Any generator that elects to become frequency responsive may face costs unique to each plant including:

- upfront costs to change plant controls
- increased fuel costs

Additional PFR provision in the NOFB may also impact regulation FCAS revenue for generators as better frequency control may reduce the amount of regulation FCAS required to be procured. However, AEMO considers that the impact of the proposed rule on both the regulation and contingency FCAS markets is likely to be minimal.[128]

Benefits to consumers of the proposed rule

The proposed rule aims to incentivise the provision of PFR under normal operating conditions. The benefits of additional PFR within the NOFB include:[129]

- increased power system resilience, reducing the likelihood of load shedding being required following frequency disturbances or other costly consequences of loss of load
- improved accuracy of measurement of the supply-demand balance, resulting in more efficient operation of generators and markets under normal operating conditions
- reducing unnecessary activation of contingency FCAS by controlling frequency closer to 50Hz
- reduced delays for plant in synchronising their generating units with the power system, which otherwise hinders operational flexibility and dispatch efficiency
- reduced wear and tear on generating plant

Each of the above benefits serves to increase power system security and reduce power prices for consumers without consumers incurring any direct costs related to implementation of the proposed rule.

AEMO's estimate of the cost-benefit trade-off

The proposed rule creates a framework under which generators can volunteer to provide PFR with compensation limited to a reduction in their exposure to Regulation FCAS costs. As a consequence, AEMO contends that the costs to be incurred by these generators would not exceed the benefits to be gained. AEMO believes the proposed rule will not result in any cost increases to consumers, either now or in the longer term, and so any benefits gained from the additional PFR will outweigh the costs.[130]

127 Ibid, p. 44.
128 Ibid, p. 43.
129 Ibid, pp. 44-46.
130 Ibid, pp. 47-48.

QUESTION 8: AEMO'S EXPECTED COSTS AND BENEFITS ASSOCIATED WITH THE PROPOSED RULE, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*

In relation to AEMO's proposed rule, *Removal of disincentives to primary frequency response*:

- What are stakeholders' views on AEMO's estimate of the associated costs and benefits?

4.2.2 Dr Sokolowski's proposed rule to address disincentives to the provision of PFR

Dr Sokolowski's proposed rule is intended to remove incentives in the NER that encourage generators to prioritise following their dispatch targets over being responsive to frequency changes in the power system. The elements of Dr Sokolowski's proposed rule that relate to removing disincentives toward the provision of PFR include proposed changes to:[131]

- clause 3.15.6A(5) to clarify that, for the purposes of determining a contribution factor for the allocation of regulation FCAS costs, a market participant is expected to achieve its dispatch targets at uniform rates subject to the provision of PFR.
- clause 4.9.4(a)(4) to clarify that both a scheduled and a semi-scheduled generating unit may send out energy as a consequence of operating in a frequency response mode. In addition, the drafting of sub-paragraph (ii) is revised to clarify that a generating unit's frequency response mode shall be subject to local power system conditions.
- clause S5.2.5.14 clarify that a scheduled generating unit or a scheduled generating system should be capable of controlling its active power output "subject to local frequency". This clause sets out the active power control requirements that apply for Generators who are negotiating an agreement for the connection of a generating unit to the power system.

QUESTION 9: DR SOKOLOWSKI'S PROPOSED CHANGES TO ADDRESS DISINCENTIVES TO THE PROVISION OF PRIMARY FREQUENCY RESPONSE

In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:

- What are stakeholders' views on Dr Sokolowski's proposed changes to the NER to address disincentives to PFR?
- Do stakeholders envisage any unintended consequences as a result of the proposed rule change?

131 Dr Sokolowski, *Primary frequency response requirement* — Electricity rule change proposal, 30 May 2019, p. 7.

4.3 Other changes proposed by Dr Sokolowski

Dr Sokolowski's proposed rule, *Primary frequency response requirement*, includes a number of other changes to the NER that are intended to improve frequency control and system security in the NEM. These other changes broadly relate to:

- AEMO's responsibility for power system security
- the treatment of inverter connected plant with respect to the provision of inertia support.

Each of these aspects of Dr Sokolowski's proposed rule are discussed below.

4.3.1 AEMO's responsibility for power system security

Section 49(1) of the NEL sets out AEMO's statutory functions, which include that it has the function:

> (e) to maintain and improve power system security

Dr Sokolowski's proposed rule would revise clause 4.3.1 of the NER to align with S49(1)(e) of the NEL and clarify that AEMO is responsible not only to maintain power system security but also to improve it.[132] In relation to Dr Sokolowski's proposal, the Commission notes that there is a requirement for AEMO to maintain and improve power system security, consistent with its obligations under the NEL, included in clause 4.1.1(b) of the NER:

> By virtue of this Chapter and the National Electricity Law, AEMO has responsibility to maintain and improve power system security. [...]

> QUESTION 10: AEMO'S RESPONSIBILITY TO MAINTAIN AND IMPROVE POWER SYSTEM SECURITY
>
> In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:
>
> - Do stakeholders consider there to be value in amending cl 4.3.1 to explicitly refer to AEMO's responsibility to improve, in addition to maintain, power system security?

4.3.2 Inverter connected plant and inertia support

Dr Sokolowski's proposed rule also includes changes to the NER to revise clause 5.20B.5(g), that relates to inertia support activities, and revise the chapter 10 definition of 'Inertia'. As noted in Dr Sokolowski's rule change request:[133]

> The proposed changes with respect to inertia support activities recognise that fast frequency response services available from inverter connected plant can be seen to be effectively equivalent to inertia support.

132 Dr Sokolowski, *Primary frequency response requirement* — Electricity rule change proposal, 30 May 2019, p. 12.

133 Dr Sokolowski, Primary frequency response requirement — Electricity rule change proposal, 30 May 2019, p.8.

This objective is addressed in the proposed rule through the revision of a note in clause 5.20B.5(g) which relates to Inertia support activities and the revision of the chapter 10 definition of 'Inertia'.

In relation to Dr Sokolowski's proposed rule change, the Commission notes that the existing clause 5.20B.5(g) specifies that 'inertia support activities' may be provided to help AEMO to operate the power system in a satisfactory and secure operating state. The provision of 'inertia support activities' may be taken into account by AEMO to reduce the minimum requirement for inertia network services provided by either a synchronous generating unit or a synchronous condenser as per NER clause 5.20B.4(d). Clause 5.20B.5(g) of the NER states:[134]

> If approved by AEMO under paragraph (a), inertia support activities may include installing or contracting for the provision of frequency control services, installing emergency protection schemes or contracting with Generators in relation to the operation of their generating units in specified conditions.

The existing drafting of clause 5.20B.5(g) allows for frequency control services, from inverter connected plant or otherwise, to be considered as 'inertia support activities' subject to approval by AEMO. Dr Sokolowski's proposed rule change would explicitly refer to fast frequency response as being a potential source of inertia support activities, by adding the following words to the end of the note following clause 5.20B.5(g):[135]

> [...] including fast frequency response from inverter-connected plant.

In addition to the proposed changes to clause 5.20B.5(g), Dr Sokolowski proposes that the definition of 'Inertia' in chapter 10 of the NER be revised as per the mark-up below:[136]

> Contribution to the capability of the power system to ~~resist~~ oppose changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is ~~electro-magnetically~~ coupled with the power system and synchronised to the frequency of the power system.

QUESTION 11: INERTIA AND INERTIA SUPPORT ARRANGEMENTS IN THE NER

In relation to Dr Sokolowski's proposed rule, *Primary frequency response requirement*:

- Is the current chapter 10 definition of Inertia appropriate and fit for purpose?
- Do the current arrangements for Inertia support activities adequately allow for Inertia support by way of fast frequency response from inverter connected plant?

134 NER clause 5.20B.5(g)

135 Dr Sokolowski, *Primary frequency response requirement* — Electricity rule change proposal, 30 May 2019, p.17.

136 Dr Sokolowski, *Primary frequency response requirement* — Electricity rule change proposal.

- How could the arrangements for Inertia and inertia support activities in the NER be improved to better utilise the capabilities of inverter connected plant?

4.4 Alternative mechanisms to improve frequency performance

Through the *Frequency control frameworks review* the Commission developed and consulted on a range of policy options to increase the provision of PFR in the NEM. These policy options may be considered as alternative solutions to address the issues raised by AEMO and Dr Sokolowski in their respective rule change requests. In assessing whether any of these options are suitable alternative solutions, it is necessary to consider whether each option would be able to effectively meet the identified power system requirements and whether it can be meaningfully implemented in a relatively short time frame to address the immediate need to improve frequency control in the NEM.

- Section 4.4.1 provides an overview of the policy options developed through the *Frequency control frameworks review* for increasing the provision of PFR
- Section 4.4.2 discusses the suitability of the policy alternatives to meet the immediate need for effective frequency control

4.4.1 Overview of potential alternative solutions

Table 4.1 provides an overview of the policy options for increasing the provision of PFR, as developed through the *Frequency control frameworks review*

Table 4.1: **Primary frequency response options**

OPTION	BRIEF DESCRIPTION	SUMMARY NOTES
A	The provision of PFR along with the provision of regulating FCAS	Under such an arrangement, a generator that is enabled to provide a regulating service would respond to both a change in locally measured frequency and to signals from AEMO's AGC system.
B	Narrowing of trigger settings for the existing contingency services	Under this option, the trigger points for some or all of the existing contingency services would be narrowed through changes to the frequency operating standard and/or the market ancillary service specification.
C	The mandatory provision of PFR	A mandatory requirement could be placed on market participants for the provision of PFR.
D	Procurement of PFR and headroom via contracts	The contract procurement of PFR would involve the specification of performance characteristics and the required quantity of service by AEMO.

OPTION	BRIEF DESCRIPTION	SUMMARY NOTES
		These services would then be procured on a periodic contract basis by AEMO or potentially a TNSP as is the case for other non-market ancillary services such as network support and control ancillary services (NSCAS) and system restart ancillary services (SRAS).
E	Development of new markets for PFR	New ancillary service markets for PFR could be developed, similar to the existing market ancillary services. This would allow AEMO to prescribe the required amount of each type of service. The provision of these services could then be dynamically optimised in response to changing power system conditions.
F	Introduction of a two-sided incentive mechanism for PFR through changes to the causer pays arrangements	The existing causer pays procedure could be revised to better incentivise the provision of PFR. The goal would be that participants whose plant helps to correct frequency are rewarded and participants that contribute to frequency deviations are levied the costs of frequency regulation.
G	Introduction of incentive payments for PFR through the development of a new deviation pricing mechanism	Incentives for the provision of PFR could be established through a new "deviation pricing" mechanism. The goal would be that participants whose plant helps to correct frequency are rewarded and participants that contribute to frequency deviations are levied the associated costs.

Source: AEMC, *Frequency control frameworks review* — Final report, pp. 90 – 98, 116 – 117.

4.4.2 Description of alternative options considered by the Commission

The following section describes the options for provision of PFR as summarised in table 4.1 as considered by the Commission through the *Frequency control frameworks review.* A brief summary of the Commission's preliminary assessment of each option and related stakeholder responses is also included for reference.

(A) Provision of a primary response with regulating FCAS

Under this arrangement, a generator that is enabled to provide the regulating raise (or lower) service would provide the service either in response to a change in locally measured frequency or in response to a signal from the AGC system. Appropriate control logic would be required to support the provision of both a primary and a secondary frequency response from a single generating unit.[137]

Findings from the Frequency control frameworks review

In response to stakeholder submissions to the *Frequency control frameworks review*, the Commission acknowledged the operational challenges associated with providing both primary and secondary frequency response through a single enablement mechanism. Such a mechanism may reduce levels of competition in the provision of regulating FCAS. Additionally, the Commission acknowledged AEMO's concerns that such an approach may not deliver a sufficient level or distribution of PFR.[138]

(B) Narrowing of trigger settings for the existing contingency services

Under this option, the trigger points for some or all of the existing contingency services are narrowed. The existing fast, slow and delayed market ancillary services are triggered in response to locally sensed frequency of the power system. Under the existing framework, these services provide a primary response to correct changes in system frequency outside the NOFB (49.85 Hz — 50.15 Hz). If some or all of these services were triggered at a narrower frequency setting, such as the deadbands proposed by AEMO or Dr Sokolowski and shown in Figure 4.2, this could help to provide the required PFR to regulate system frequency during normal operation.[139]

Findings from the Frequency control frameworks review

In the *Frequency control frameworks review* draft report, the Commission recognised that amending the levels in the existing frequency operating standard or the MASS to use contingency services for the management of frequency within the normal operating band represents a substantial shift in the approach to frequency management in the NEM. Allowing for a narrower activation of contingency services as set out in option B was considered by the Commission to be a relatively inflexible and blunt instrument for the purpose of improving frequency performance.[140]

At the time the draft report was written, the Commission considered that while such changes may be warranted in the long term, at the time it was not clear that the benefits of such a change exceed the associated costs. However, AEMO's current advice now implies that a fundamental change to the approach to frequency control in the NEM may be necessary in the immediate future to maintain security of the power system.

(C) The mandatory provision of PFR

A mandatory arrangement for the provision of the PFR could be designed with or without the inclusion of a requirement for maintaining a specific headroom capacity. For example, the

137 AEMC, *Frequency control frameworks review* — Draft report, 20 March 2018, p. 73.

138 AEMC, *Frequency control frameworks review* — Final report, 26 July 2018, pp. 121-123.

139 AEMC, Frequency control frameworks review — Draft report, 20 March 2018, pp. 75-76.

140 Ibid, p. 89

requirement may state that the response must be provided only by generators that are capable of providing the response, in terms of the technical capability of the generator and the available operating capacity. This option implies that the generating unit is to be operated in a frequency responsive mode, but is not required to withhold capacity from the energy market in order to provide the response.[141]

AEMO's and Dr Sokolowski's rule change requests propose versions of option C, with AEMO also proposing that generators that are not technically capable should modify their control systems to become capable.

Findings from the Frequency control frameworks review

The Commission considers that a mandatory obligation to provide PFR is likely to deliver both improved frequency performance during normal operation and improved system resilience to multiple contingency events. A mandatory requirement for PFR without headroom would likely send a clear signal to market participants to drive operational behaviour that will support both frequency regulation and system resilience.[142]

However, the Commission also recognised that such mandatory requirements may be difficult to apply to generators with existing connection agreements and would not provide the financial incentives to support innovative approaches to improve frequency response capability.[143]

(D) Procurement of PFR and headroom via contracts

Under a contract procurement model, AEMO would specify the performance characteristics and quantity of PFR and these criteria would be incorporated into a contract for services that may be made between the service provider and AEMO or potentially a TNSP. Contracts could be established via a competitive tender process or bilaterally negotiated process.

Service providers would not be limited to generators capable of providing a governor response. Any market participant with the ability to control the active power supply or demand at their connection point, in response to variations in power system frequency, could provide the service.[144]

Findings from the Frequency control frameworks review

The Commission considers that if an emerging power system need is identified, a contracting approach may be attractive (at least as an interim arrangement) in order to enable AEMO to be able to procure PFR as required. A contract market for a PFR service may provide an appropriate solution if certainty over the quantity of response is required and this quantity is relatively stable over time. A contract market may however be less transparent and less flexible than a real-time market.[145]

141 Ibid, p. 79
142 Ibid, p. 88
143 Ibid, p. 81
144 Ibid
145 Ibid, p. 89

Consideration would also need to be given to the definition of the PFR service that was being contracted. AEMO's proposal is for a broad-based provision of PFR from a large number of generators across the NEM but with no requirement to specifically maintain headroom. A contracting approach would likely be more suitable to procuring PFR from a limited number of generators with the maintenance of headroom specified as part of the contract arrangements in order to guarantee a response.

(E) Development of new markets for PFR

The provision of PFR could be incentivised through the formation of new markets for frequency control services. Setting up separate markets for raise and lower PFR services would allow AEMO to prescribe the required amount of each type of FCAS dynamically in response to changing power system conditions and for these services to be co-optimised through the NEM dispatch engine (NEMDE), as is the case for the existing regulation and contingency services. A new market for PFR could operate alongside the existing contingency and regulation FCAS markets and could be implemented with limited impact on either.[146]

Findings from the Frequency control frameworks review

The introduction of a new PFR service through the establishment of a new market could be an effective approach to improving frequency control in the NEM. However, the Commission considered that such an approach is likely to be contingent on the ease of implementation, which would likely require a rule change request, changes to the frequency operating standard, changes to the MASS and potential consequential changes to the existing FCAS markets.[147]

(F) Introduction of a two-sided incentive mechanism for PFR through changes to the causer pays arrangements

Incentives for the provision of a primary regulating response could be established through changes to the existing causer pays arrangements. Under the current AEMO causer pays procedure, contribution factors are intended to represent the extent to which a market participant has contributed to a frequency deviation (i.e. whether a market participant's deviation from dispatch instructions has contributed to frequency deviating from 50Hz). The individual market participant factors are averaged across portfolios and where a contribution factor is assessed to be greater than zero, i.e. has a net positive impact (improvement) on frequency control, it is set to zero.

Incentives for market participants to provide PFR could be provided by allowing for positive contribution factors to be rewarded. This could be based on an identical proportional response to the value of negative contribution factors or some other proportional payment. No additional data would be required from generators to implement this option. The only procedural change would be to no longer constrain the value of contribution factors to a maximum value of zero.[148]

146 Ibid, p. 82
147 Ibid, p.89.
148 Ibid, p. 86

Findings from the Frequency control frameworks review

The Commission considered that the introduction of incentive payments to the causer pays arrangements would create a balanced price structure that penalises or rewards the behaviour of eligible market participants based on whether they contribute to frequency deviations or respond to correct such deviations. This approach would likely to encourage innovative technical and financial arrangements to support frequency control. Reporting under this approach would likely be required in order to increase transparency around the levels of frequency response that are active in the system.[149]

(G) Introduction of incentive payments for PFR through the development of a new deviation pricing mechanism

The deviation pricing framework represents a decentralised model in which decisions to be frequency responsive are made by each market participant in response to incentives provided through a transparent pricing mechanism. Market participants are paid if their actions assist in moving the system frequency back towards 50 Hz. The pricing mechanism is based on a transparent symmetric price function with a rapidly increasing incentive (price) as frequency deviates further from the central target of 50 Hz. A key feature of a deviation pricing mechanism is that it allows all frequency control technologies to be appropriately valued in accordance with the speed and profile of their response.

The cost of these payments is recovered from market participants that contribute to the frequency deviations. This would provide an incentive for market participants to limit the extent to which they deviate from the linear trajectory of their dispatch targets.

Under a fully decentralised approach, deviation pricing would not involve any pre-purchase of headroom (or participation in the regulation FCAS market) but would simply rely on market participants responding to pricing incentives to act in a way that supports good frequency outcomes.[150]

Findings from the Frequency control frameworks review

The Commission considers that a deviation pricing mechanism would provide a balanced two-way system of payments and charges that provides an incentive for market participants to track the trajectory of their generation or load in a manner that supports system frequency. If the incentives are sufficient, the self-interest driven behaviour of market participants would ensure that the desired frequency quality is achieved.[151]

A deviation pricing mechanism constituting a transparent system of rewards and penalties would allow participants to easily understand how their actions relate to the costs they are likely to incur. The Commission believes that this would likely increase investment certainty for participants and thereby lower the overall long-term costs of frequency control.[152]

149 Ibid, p. 89

150 Ibid, pp. 161-163

151 AEMC, *Frequency control frameworks review* — Final report, 26 July 2018, p. 41.

152 Ibid, p. 91.

A discussion of the technical and temporal requirements for providing effective PFR and related questions for stakeholders to respond to are included in section 6.1.

5 ASSESSMENT FRAMEWORK

This chapter sets out the AEMC's proposed assessment framework for the PFR rule changes. It also includes an overview of the other aspects of the rule change process, including the Commission's ability to make a more preferable rule, if required.

Stakeholders are encouraged to comment on the appropriateness of this proposed assessment framework in relation to the rule change request.

5.1 Assessment priorities

The Commission will prioritise solutions to the issues raised in the rule change requests from AEMO and Dr Sokolowski in accordance with the following hierarchy of priorities:

1. Addressing risks to power system security associated with the degradation of frequency control in the NEM and the withdrawal of PFR from market participants not enabled to provide FCAS
2. Alleviating disincentives in the NER to market participants operating their plant in a way that helps correct frequency deviations
3. Improving incentives for market participants to operate their plant in a way that helps correct frequency deviations.

As discussed in section 1.1.1, AEMO has requested that its rule change request, *Mandatory primary frequency response*, be assessed in the shortest reasonable timeframe, balancing the requirement for appropriate consultation with the potential consequences of the ongoing lack of effective frequency control during normal operating conditions. In determining a solution, the Commission will seek to address system security first and foremost. While the Commission acknowledges the need to optimise economic efficiency of service delivery, it also considers that this should not come at the expense of a secure and stable power system. When the fundamental system security needs are met, the Commission will seek to investigate further improvements to the frequency control arrangements to increase the overall economic efficiency of frequency control in the NEM. This approach is consistent with the frequency control work plan that was agreed as part of the *Frequency control frameworks review* in which the Commission recommended the development of a mechanism to incentivise the provision of a sufficient quantity of PFR over the long term to support good frequency performance during normal operation.

5.2 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[153] This is the decision-making framework that the Commission must apply.

The NEO is:[154]

153 Section 88 of the NEL.
154 Section 7 of the NEL.

> To promote efficient investment in, and efficient operation and use of, electricity services for the longer term interests of consumers of electricity with respect to -
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Based on a preliminary assessment of the issues raised by the proponents in the rule change requests, the Commission considers that the relevant aspects of the NEO for further consideration are the efficient investment in, and operation of the electricity system and related equipment with respect to the price of electricity, as well as the safety and security of the national electricity system.

In assessing each of the rule change requests, the Commission will consider whether the proposed rule is likely to support and improve the security of the power system along with the effectiveness and efficiency of frequency control frameworks. In particular, it will consider the following principles:

- **Promoting power system security**: The operational security of the power system relates to the maintenance of the system within pre-defined limits for technical parameters such as voltage and frequency. System security underpins the operation of the energy market and the supply of electricity to consumers. The Commission will have regard to the potential benefits associated with improvements to system security brought about by the proposed rule changes, weighed against the likely costs. In relation to system security, a rule for the provision of PFR is likely to be consistent with the NEO if the operational costs of compliance and service provision are less than the estimated risk-based costs of unserved energy associated with generation and load shedding following non-credible contingency events.
- **Appropriate risk allocation:** The allocation of risks and the accountability for investment and operational decisions should rest with those parties best placed to manage them. The arrangements that relate to frequency control should recognise the technical and financial capability of different types of market participants to respond to changes in frequency. Where practical, operational and investment risks should be borne by market participants, such as businesses, who are better able to manage them.
- **Efficient investment in, and operation of, energy resources to promote secure supply**: The market and regulatory arrangements that relate to frequency control should result in efficient investment in, and operation of, energy resources to promote a secure supply of electricity for consumers. The frequency control frameworks should also seek to minimise distortions in order to promote the effective functioning of the market. In the case of the arrangements for frequency control, market participants should be encouraged to invest in and operate plant in a way that supports the control of system frequency.
- **Technology neutral:** Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind.

Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

- **Flexibility:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment. Where practical, regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating security outcomes where required, while not imposing undue market or compliance costs.
- **Transparent, predictable and simple:** The market and regulatory arrangements for frequency control should promote transparency and be predictable, so that market participants can make informed and efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to implement, administer and participate in.

In assessing whether the proposed rules are likely to meet the NEO, the Commission will balance out the power system needs and related benefits associated with improving system security, resilience and power system frequency control against the cost of delivering those outcomes. The Commission notes that while improved frequency control may provide benefits to consumers by delivering enhanced power system security and resilience, such improvements may also incur additional costs which are likely to be ultimately borne by consumers.

At a high level, some of the potential benefits of improved frequency control associated with the provision of narrow band PFR may include the following:

- Improved system security and resilience is an expected result of the power system frequency being maintained more closely to the nominal frequency of 50Hz and away from the load shedding band and extreme frequency tolerance limits. If the power system frequency is further away from 50Hz when a contingency event occurs, the resulting frequency deviation may be more severe. This could in turn lead to an increased likelihood of load shedding and potentially a cascading outage and black system.
- Improved power system frequency performance may deliver benefits through reducing the operation and maintenance costs of generation equipment. This reduced operation cost may be a product of potential reductions in maintenance costs and improvements in generator fuel efficiency through maintaining the power system frequency closer to 50 Hz.

However, there are costs associated with the implementation of a mechanism to increase the provision of narrow band PFR in the NEM, including:

- implementation costs associated with upgrading generation plant to meet the technical requirements for the provision of PFR. Such costs are likely to increase as the technical requirements for PFR are made more stringent or the proportion of the generation fleet that is required to be responsive to changes in system frequency is increased.

- ongoing operation costs associated with providing PFR. These costs relate to fuel and maintenance costs that are incurred by generators who are responsive to change in frequency and would not be incurred by non-responsive plant. These costs are understood to be proportional to the scale of ongoing frequency variation and, for most plant, can be reduced through frequency being held more closely to 50Hz.

An initial consideration of the costs and benefits of the proposed rule is included in section 6.2.

5.3 Making a more preferable rule

Under s.91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

5.4 Northern Territory

From 1 July 2016, the NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the NT legislation adopting the NEL.[155] Under those regulations, only certain parts of the NER have been adopted in the NT. (See the AEMC website for the NER that applies in the NT.)

As the proposed rule related to parts of the NER that currently do not apply in the Northern Territory, (i.e. chapter 3, 4 & 5 of the NER) and any consequential changes to other chapters of the NER will have no practical effect in the Northern Territory (i.e. if transitional arrangements were introduced under Chapter 11 of the NER), the Commission does not consider that the proposed rule needs to be assessed against additional elements set out under the Northern Territory legislation.

QUESTION 12: ASSESSMENT FRAMEWORK

In relation to the AEMC's proposed assessment framework for the PFR rule changes:

- Do stakeholders consider that the assessment framework is adequate for considering the PFR rule change requests from AEMO and Dr Sokolowski?
- Are there any other relevant considerations that should be included in the assessment framework for the PFR rule changes?

155 National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.

6 ISSUES FOR CONSIDERATION

This chapter explores two principal factors which the Commission considers have the potential to influence the design of the final rule that is made with respect to each of the rule change requests.

- Section 6.1.1 discusses the technical and operation requirements of PFR that are necessary to support the secure operation of the power system.
- Section 6.1.2 discusses the temporal constraints and the time-frames available to design and implement a mechanism that will support the security of the power system at least cost.

Based on an understanding of the technical and temporal requirements to deliver narrow band PFR for effective frequency control, section 6.2 provides a summary of the Commission's preliminary thinking on the trade-off between the benefits of improved frequency control and the associated.

6.1 Technical and temporal requirements of PFR

In determining suitable solutions to the rule change requests submitted by AEMO and Dr Sokolowski, it is necessary to consider the technical and operational needs of the power system and the need to be able to implement the solution in a time frame that is consistent with the urgency of the requirement.

6.1.1 Technical and operational goals of effective PFR

The maintenance of a secure power system is dependent on the effective control of frequency. One of the principal means of controlling frequency is through the provision of PFR. Whether or not the PFR that is provided is sufficient to ensure a secure power system is dependent on the technical characteristics of the PFR. These characteristics play a critical role in determining the range of conditions under which the frequency will be effectively controlled. The provision of PFR from a large proportion of the generating fleet across a wide geographic area is likely to be more effective in controlling frequency and maintaining a secure power system than a frequency response provided from a smaller proportion of the generating fleet over a more confined geographic area.[156]

The principal objective of the PFR rule change requests is to re-establish effective frequency control in the NEM, in line with standard international practice. This section discusses the technical and operational attributes of PFR that are necessary for effective frequency control.

A broad-based PFR response

In its rule change request, AEMO notes that generators have become less responsive to frequency variations over time and, as a consequence, the NEM is trending towards a

156 AEMO, Response to request for advice — *Frequency control frameworks review*, 5 March 2018, pp.5-6.

situation where the majority of primary frequency response is concentrated amongst the few generating units which are enabled for the provision of contingency FCAS.[157] If this trend continues, the only generating units providing primary frequency response would be the select few that offer frequency response reserves at the lowest price in any dispatch interval. AEMO raises the following concerns with this arrangement:

- Contingency FCAS would be the only source of response to correct frequency before the activation of any emergency frequency response schemes. Any redundancy or safety margins in PFR would be removed.
- It would be critical for all Contingency FCAS providers to behave exactly as required, which based on operational experience is a highly unrealistic expectation in all circumstances.
- The resilience against any behaviours or responses beyond the simple contingency events considered in the market design would be reduced, or removed.
- Power system performance following non-credible contingency events would be increasingly uncertain, and dependent on FCAS that was not intended to manage the types of more complex events to which the NEM is now more exposed.
- The ability of island regions, or sub-regions, to meet FOS standards for recovery following major disturbances would be reduced.

While acknowledging these concerns raised by AEMO, it is arguable that many of these concerns may be addressed through increasing the volume of contingency FCAS that is procured to respond to sudden system disturbances. For example, procuring additional contingency FCAS could provide a safety margin before the activation of emergency frequency control schemes. Equally, additional contingency FCAS sourced from a greater number of providers could potentially resolve the issue that some FCAS providers may not behave exactly as required. The procurement of additional contingency FCAS could also support the ability of islanded regions to recover following major disturbances by increasing the range of FCAS providers across the NEM.[158]

However, there are also factors amongst the concerns raised by AEMO that would suggest that simply increasing the procured volume of contingency FCAS would not be sufficient to support power system frequency on its own. In particular, PFR provided by a small number of generators may not be adequate for the more complex disturbances to which the NEM is increasingly being exposed. In order to maintain a secure system in the face of these disturbances, a significant proportion of the generating fleet would be required to provide a primary frequency response across as large as possible geographic proportion of the power system.

AEMO considers that there is a need for broad-based provision of PFR from the largest possible amount of generation, responding outside narrow deadbands, for the following reasons.

157 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.27.

158 It is possible that the additional volume of contingency FCAS would need to be supplemented by constraints imposed to limit the volume of FCAS procured in each region.

- **Caters to a more complex and less predictable power system** — Power system disturbances are becoming more complex and less predictable. This can be attributed to physical changes in the power system such as reduced levels of system strength which can increase risks of unexpected control behaviours from inverter connected generation. To manage the ongoing operation of the power system, AEMO has been reclassifying some contingency events as credible, such as the loss of large loads or HVDC links. In addition, the ongoing increase of small distributed PV has compounded the size of deviations when larger system disturbances occur. The impacts of this distributed PV was observed in the events of 3 March 2017 in SA and across the NEM on 25 August 2018. The consequences of this are that the power system is now exposed to a greater range of potential outcomes which AEMO must manage in order to maintain power system security. Greater power system resilience through the broad-based provision of PFR is required to manage these more complex disturbances.[159]
- **Allows for improved power system planning** — A broad-based provision of PFR provides more predictable and consistent generator behaviour which facilitates good planning. Planning the design of emergency frequency control schemes, such as UFLS and OFGS, requires an understanding of the performance of available PFR. Generator control system parameters, which are based on FCAS enablement, can change dynamically which makes the range of possible responses from these generators very broad. This can make planning of emergency control schemes complicated which can compromise scheme performance. AEMO considers that designing schemes based only on PFR available from the FCAS markets would likely lead to overly conservative assumptions and sub-optimal settings.[160]
- **Increases power system resilience** — The consequences of a disturbance to the power system are minimised if any provider of PFR does not respond as expected, or is unable to respond due to a network separation.[161]Broadly distributed, continually activated PFR may offer considerable resilience for non-credible or other unanticipated events.[162]
- **Minimises individual generator responses** — The duty on any individual generating unit is minimised because all generators respond together in proportion to their size, both under normal conditions and following disturbances.[163] Small responses provided by a large number of generators allows each individual generator to sustain its response for longer, thereby providing a more effective transition between the automatic primary frequency response and the secondary regulating response.
- **Minimises the size of power flow changes** — The potential size of power flow changes on the network are reduced in response to an event, which minimises the consequential impacts of disturbances. AEMO considers that PFR which acts close to the cause of a frequency deviation is likely to be the most effective in responding to the

159 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.24.
160 Ibid. p.26.
161 Ibid. p.20.
162 AEMO, Response to request for advice — *Frequency control frameworks review*, 5 March 2018, pp.5-6.
163 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.20.

disturbance, and reduces the likelihood of oscillations occurring in the power system which can result from remote frequency responses. AEMO suggests that this is particularly important in a more geographically dispersed and weakly meshed power system such as the NEM.[164]

AEMO engaged international power system expert, Dr John Undrill, to assess the appropriateness of NEM frequency control arrangements against typical international practice, and advise on what changes may be required to alter NEM frequency outcomes. The advice from Dr Undrill states that prudent power system operation requires that grid frequency be maintained within the narrowest practical band. The advice includes the recommendation that:[165]

> The obligation to provide primary control response to variations of frequency should be applied to the widest practical part of the generating fleet. The obligation should apply, to the extent that it is practical, to all generating resources including those that are coupled to the grid through electronic inverters.

AEMO interprets Dr Undrill's advice as recommending:[166]

> broad-based provision of PFR from the largest possible amount of generation, responding outside narrow deadbands.

Meeting the technical requirements

The mandatory provision of PFR has been proposed by AEMO and Dr Sokolowski in their respective rule change requests as a solution to the immediate need to restore effective frequency control in the NEM. During the *Frequency control frameworks review*, this policy option was considered as a potential frequency control solution and it is included in Table 4.1 under option C.

The fundamental characteristics of a mandatory PFR obligation are that it would apply to a large proportion of the generating fleet. Therefore, it is likely to meet the technical and operational goals for effective frequency control as discussed above.

AEMO considers that a mandatory obligation is required as a broad distribution of PFR throughout the power system cannot be economically implemented through the existing market design.

One alternative arrangement to mandating narrow band frequency control would be to require contingency FCAS providers to respond outside of a narrow deadband, similar to option B which is described in section 4.4. This option could be complemented with the procurement of localised FCAS requirements on a regional basis to improve the resilience of the power system to regional separation due to contingency events. AEMO is currently

164 AEMO, Response to request for advice — Frequency control frameworks review, 5 March 2018, p.5.

165 J. Undrill, Notes on Frequency control for the Australian Energy Market Operator, 5 August 2019, pp. 2-3.

166 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.12.

considering the potential benefits for increasing the geographic diversity of FCAS through some form of regional allocation for these services.[167]

The Commission notes the following challenges associated with continuous narrow band PFR being provided only by plant enabled through the FCAS markets to provide contingency FCAS:

- The size of the expected changes in active power output for each service provider would be quite severe in comparison with a broad-based requirement on most of the generation fleet. This is expected to increase the operational costs associated with providing narrow band PFR.
- The frequency response duty on any one provider of contingency FCAS could be reduced through the introduction of a cap on the amount of contingency FCAS that an individual FCAS provider can be enabled for. This would have the effect of increasing the number of enabled service providers. However, such measures would be likely to reduce the competition for provision of contingency FCAS and could result in other operational challenges.

Under AEMO's proposed arrangements, the mandatory obligation for all generators to provide frequency response would apply alongside the existing market arrangements for FCAS. The FCAS markets would continue to operate in their current form but the objective of these markets would be to maintain a prudent minimum level of headroom, or frequency control reserve, across the NEM, in the most economical manner.[168]

As part of the *Frequency control frameworks review*, the Commission suggested that options for the delivery of PFR could be thought of as reflecting a greater or lesser reliance on two principal approaches:

1. Market-based mechanisms
2. Intervention or regulatory mechanisms

There are different costs and benefits for market-based or regulatory based approaches. Intervention or regulatory based approaches tend to involve a centralised or direct control over security, which provides a high degree of certainty that a secure supply of electricity will be achieved. These approaches would involve more direct control over the provision of PFR such as would be achieved through a mandatory obligation, as proposed by AEMO, or a contracting approach.

However, these approaches also tend to foreclose the considerable potential benefits of a well-functioning market, potentially imposing costs and risks on consumers. In these cases, more distributed control over the provision of services can achieve economically superior outcomes, but may reduce levels of confidence where security concerns are manifesting in operational time scales or where the risk external to the energy market prevents it from being well-functioning. These approaches are characterised by some version of performance-

167 AEMO, Mandatory primary frequency response - Electricity rule change proposal, 16 August 2019, pp.37-38. AEMO, Final report - Queensland and South Australia system separation on 25 August 2018, 10 January 2019, p.8.

168 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.47.

based pricing where frequency control is undertaken by market participants through local response to locally measured frequency deviations.

A performance-based pricing mechanism does not require the development of a pre-specified profile of response, as would be part of a separately defined service or contracting approach. Instead, participants are rewarded and penalised in proportion to the impacts of their actions on frequency and the value they provide to the system. This allows frequency providers to tailor their actions to the costs of providing a response and allows the response from a greater range of technologies to be valued, thereby maximising levels of participation.

QUESTION 13: TECHNICAL REQUIREMENTS OF EFFECTIVE PRIMARY FREQUENCY RESPONSE

In relation to the discussion of the technical requirements for effective frequency control and the policy options described in section 4.4:

- How do stakeholders view the ability of market or regulatory approaches to provide the necessary broad-based frequency response from participants?
- What issues are likely to arise with market or regulatory approaches in achieving the objective of a broad-based frequency response?

6.1.2 Temporal considerations — the need for an immediate solution

The Commission considers that the economic optimisation of the provision of PFR is an important consideration in minimising the long-term costs to consumers. However, this needs to be balanced against the potential consequences of an insecure power system. Addressing the immediate system security need will require the design and implementation of a mechanism in a relatively short time period. A longer-term performance-based pricing approach, as recommended in the *Frequency control frameworks review*, would require a longer time period for design and implementation. Furthermore, the necessary testing and trialling of such a mechanism would not likely be appropriate in the current power system, where a deficiency in good frequency performance has been identified. The implementation of a longer-term framework to more effectively optimise the economic provision of frequency control is likely to require further development when the immediate system needs are satisfied.

Addressing system security as a priority

As discussed in chapter 5, in the first instance the Commission intends to prioritise addressing risks to power system security associated with the degradation of frequency control in the NEM, and will prioritise the development and implementation of a solution that supports the secure operation of the power system. The Commission acknowledges AEMO's advice that the reduced sensitivity of the generation fleet to frequency deviations is contributing to a reduction in the resilience of the power system to contingency events.

However, the Commission also notes that the economic optimisation of the provision of PFR is also an important consideration in minimising the long-term costs to consumers. This was reflected in the Commission's key recommendations made in the final report of the *Frequency control frameworks review* that, in the long term, market participants should be incentivised to provide a sufficient quantity of primary frequency response to support good frequency performance during normal operation. Importantly, the Commission considers that regulatory arrangements should continue to evolve in order to efficiently value the provision of frequency control to keep pace with the system transformation. To the extent achievable within the time frames available, the Commission intends to develop a reform pathway that will allow for this evolution to minimise the overall costs to the market of providing PFR but which, first and foremost, allows for the security of the power system to be addressed.

In AEMO's view, the preferred means of adequately addressing the need for a more secure power system is to mandate the provision of PFR from as large a number of generators as possible across the NEM. AEMO has formed the view that the decline in power system frequency performance needs to be arrested urgently and that the power system cannot wait until a more comprehensive solution is developed, as envisaged by the AEMC in the *Frequency control framework review* final report.[169]In AEMO's view, such a mechanism would take three to four years to debate, design and trial before it could be successfully implemented.

Nevertheless, AEMO's incident report on the events of 25 August 2018 made several recommendations to address the decline in frequency performance, one of which is to support work on a permanent mechanism to secure adequate PFR as contemplated in the AEMC's *Frequency control framework review*.[170] This view was reiterated by AEMO in its *Mandatory primary frequency response* rule change request.[171]

The Commission considers that a contract-based mechanism may also be a potential suitable alternative to restore effective frequency control in the NEM within a relatively short implementation time-frame. The Commission is aware that a contracting approach has been operating effectively in the UK for a number of years. An overview of the UK arrangements for mandatory frequency response is included in appendix f.

While a similar contract-based procurement approach for continuous narrow band PFR may be possible for the NEM, there are a number of design issues that would need to be resolved before effectively implementing such a mechanism. In particular:

- A contracting approach may suffer from similar issues as described above in relation to Contingency FCAS markets. Specifically, if there are only a small number of contracted providers the size of the expected changes in active power output for each provider would be quite severe in comparison with a broad-based requirement. The frequency response duty on any one provider could be reduced by increasing the number of

169 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.12.

170 AEMO, Final Report — Queensland and South Australia system separation on 25 August 2018, 10 January 2019, p.88.

171 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.11.

contracted providers. However, such measures would be likely to reduce competition for the provision of PFR.

- AEMO's advice is that a broad-based provision of PFR would be best achieved by a large proportion of the generating fleet providing a response. While generators could maintain headroom so as to be able to guarantee the provision of a response at all times, this is not considered to be necessary, and indeed would likely impose a high cost on the market and consumers. Therefore, a contracting approach to provide PFR would only require generators to provide a response if and when they are able. The terms of payment under any such contracts would need to be negotiated but it would seem reasonable to assume that generators would only be paid at times they are actually providing a response. This would require a means of determining the exact response that was provided and at which times, which may be difficult to accurately measure.

The Commission is interested to hear from stakeholders in relation to the appropriateness of such a mechanism to restore effective frequency control in the NEM.

Implementing changes to generator control systems

In his advice to AEMO, John Undrill notes that the process for implementing physical changes to generator governor controls is likely to be a large and complex undertaking. As many generators as possible will need to participate in the provision of PFR in order to address the security needs of the power system. Furthermore, there will need to be a coordinated effort of changing controls on generators, as a generator-by-generator approach to adjusting governor controls will likely see those generators whose controls were adjusted first executing large responses to variations in frequency with very little effect. As discussed in section 6.1.1, multiple generating units contributing effectively to control variations in frequency would minimise the impact on any individual generator.

Advice from John Undrill suggests that field trials are likely to be the only effective means of assessing changes in practice regarding primary control.[172] These trials are likely to be a large undertaking as they would necessarily need to involve at least a third or more of the generating fleet with governors set to act in the proposed manner. A trial involving a small number of generating units would not give any useful indication of the extent to which frequency could be controlled when multiple plants contribute effectively to controlling frequency.

However, AEMO also suggests that time frames for implementation could be reduced as a significant proportion of NEM generation is already providing, or capable of providing, PFR to varying degrees, and via various control arrangements. AEMO's proposed rule, *Mandatory primary frequency response*, includes transitional rules that would allow for AEMO to prepare and publish an interim *Primary frequency response requirements* document to apply from the commencement date of the rule. AEMO's draft PFRR includes an implementation time frame that incorporates a requirement for generating systems with a registered capacity over 200MW to submit to AEMO within a 60 business-day period a self assessment as to whether

172 John Undrill, Notes on Frequency Control for the Australian Energy Market Operator, 5 August 2019, p.12.

they can meet the PFR technical requirements.[173] AEMO would then respond to the Generator within 20 business days and then work towards implementing the changes to the Generator's control systems, thereby allowing for generating systems with a nameplate rating of 200MW or more to be the first required to meet the new requirements for PFR. The remaining (technically capable) scheduled and semi-scheduled generating systems would be required to adjust their plant after this first tranche is completed.

QUESTION 14: TEMPORAL CONSIDERATIONS

In relation to the discussion of the temporal requirements for the development and implementation of a solution to deliver effective frequency control:

- How do stakeholders reconcile the need to address system security with the objective of minimising the long-term costs to consumers?
- Do stakeholders consider the need to address system security in a timely manner as influencing the mechanism adopted to address the issue?
- Do stakeholders consider the process of implementing physical changes to generator governor controls as influencing the choice of mechanism?

6.2 Considering the trade-off between costs and benefits

As discussed in chapter 5, the Commission must consider the trade-off between the costs associated with making a rule to require the provision of PFR and the associated benefits.

AEMO and Dr Sokolowski have indicated that the current operating framework in the NEM is not consistent with international practice for power system operation in relation to frequency control. The objective of the proposed rules is to reinstate effective frequency control in the NEM to support the security and resilience of the power system.

As discussed in section 6.1, the AEMC understands that this objective will be met through a significant proportion of the generation fleet providing PFR outside of a narrow frequency response deadband.

The following sections discuss Commissions initial considerations on how to consider a cost benefit trade-off in the design of an effective PFR mechanism.

6.2.1 Benefits

Based on the rule change requests discussed in this paper and previous investigations through the *Frequency control frameworks review*, the Commission understands that the benefits of implementing a mandatory obligation to deliver PFR from a significant proportion of the generation fleet are expected to include system security benefits, market operation benefits and benefits associated with the operation of generation plant.

173 AEMO, Primary frequency response requirements — Electricity rule change proposal, 16 August 2019, p. 44.

System security benefits

The system security benefits associated with improved frequency control relate to a reduction in the severity of the impacts following contingency events, particularly those events that exceed the largest credible contingency event. Improved frequency control gives AEMO more confidence that it is maintaining the power system in a secure operating state. In addition, any frequency response that is provided in excess of the markets for contingency capacity reserves, or FCAS, offset the need for generation and load shedding to rebalance supply and demand following a contingency event that exceeds the largest credible contingency event.

The main economic benefits of this improved frequency control include:

- a decreased risk of unserved energy associated with load shedding following large contingency events
- a decreased risk of generation shedding following large contingency events

Market operation benefits

The provision of narrow band PFR is also likely to deliver economic benefits through more efficient market operation and procurement of market ancillary services. At a high level the related benefits include:

- A potential reduction in expenditure on FCAS procurement by AEMO, predominantly due to a potential reduction in the need for regulation services. In the absence of sufficient PFR, AEMO has recently increased the base quantity of regulation services that it procures to control frequency during normal operation. As described in section 2.1.2, the effective control of frequency requires a combination of primary and secondary control. The inclusion of sufficient PFR that is responsive to frequency within the NOFB may allow for the quantities of regulation service procured by AEMO to be reduced.
- Improved market outcomes due to improved success rate for synchronous generators to synchronise to the power system and be available for dispatch.
- Improvements in the efficiency of market operation due to more accurate measurement and prediction of the system operating state. Improved frequency control during normal operation means that the frequency will be held more closely to 50.0Hz and therefore the assumptions that relate to system frequency that underpin the operation of the energy market are likely to be more accurate. This may translate into improved accuracy of demand forecasts and improved market dispatch efficiency.

Plant operation Benefits

Improved frequency performance, particularly during normal operation translates into a more stable system frequency that is maintained more closely to 50.0Hz. This improvement in frequency control may lead to a reduction in operation and maintenance costs for synchronous generating plant.

The rotating speed of synchronous plant is directly linked to the power system frequency, therefore any change in system frequency causes a direct change in the rotating speed of the generator and turbine. The ongoing instability of power system frequency can therefore translate into stress on the components of the generation plant, which over time may lead to an increased need for plant maintenance. The costs of plant maintenance include the direct costs of replacement parts and labour along with the lost revenue associated with plant shut downs to undertake the maintenance.

Improved power system frequency is likely to lead to smoother operation of synchronous generating plant and a reduction in maintenance and shut down costs as compared with operating plant in a system with poor frequency control.

6.2.2 Costs

There are costs associated with the implementation of a mechanism that results in a significant proportion of the generation fleet providing narrow band PFR. The Commission proposes to consider separately the ongoing costs associated with operating generation plant in a frequency response mode and the upfront costs associated with making changes to generation plant in order to meet the technical requirements for PFR.

Ongoing costs

The ongoing costs to generators that is associated with the provision of PFR relates to an increase in the operation and maintenance costs of synchronous generating plant. The Commission understands that, for very small continuous changes in active power, the costs of frequency response for each synchronous generating unit are expected to be very low. This understanding is supported by the recent advice provided to AEMO by John Undrill and the advice provided to the AEMC by Nick Miller during the *Frequency control frameworks review*. Based on operational experience in the North American power system, Nick Miller's advice was that the operational costs associated with the provision of primary frequency response by synchronous generation units are likely to be negligible when compared to other factors like variation in fuel price.[174]

Similarly, the recent advice provided by John Undrill states that while large changes in active power from synchronous generating plant do translate into increased operation and maintenance costs, continuous small scale manoeuvring is easily tolerated. That is, the ongoing costs for each generator that operates in a frequency response mode are understood to decrease as the proportion of the fleet that is responsive increases. [175] John Undrill's advice is that there is no good evidence to support the view that continuous small scale changes in active power output from synchronous generation translate into material costs associated with wear and tear on generation plant components or any reduction in overall operating efficiency. John Undrill's concludes that the provision of PFR should be distributed as widely as possible throughout the generation fleet so that the extent of manoeuvring for primary control of each individual turbine-generator unit should be as small as possible.[176]

Upfront costs to meet the technical requirements for PFR

174 Nick Miller, Advice on the costs of primary frequency regulation, 20 March 2018. Nick Miller has worked for many decades with GE Energy, most recently as Senior Technical Director Energy Consulting and was project lead for the AEMO report on Technology capabilities for fast frequency response, published March 2017. Mr Miller has previously provided technical advice to the Finkel review and the US Department of Energy and North American Electric Reliability Corporation (NERC).

175 This statement is based on the expected costs of a generator being operated in frequency response mode without the need to maintain operating headroom.

176 John Undrill, Notes on Frequency Control for the Australian Energy Market Operator, 5 August 2019, pp. 11-12

While there is some evidence that the ongoing costs associated with providing PFR are likely to decrease as a larger proportion of the generation fleet is responsive to frequency, this is not likely to be the case for the upfront costs associated with changes to plant to meet the technical requirements for PFR. The Commission expects that the costs for each generator to meet the technical requirements for PFR will vary. Some generation plant are likely to meet the technical requirements for PFR with minimal need for plant changes, this capability can be utilised for a relatively low upfront implementation cost. Other generation plant will require more significant plant upgrades and control system tuning in order to provide PFR in accordance with the technical requirements.

The Commission expects that these upfront costs are likely to increase in proportion to:

- increases in the technical requirements for PFR, including sensitivity (deadband), strength (droop), speed of response, and sustain time
- increases in the proportion of the fleet that is responsive to changes in frequency.

A key factor in the scale of these upfront costs is the existing capability of the generation fleet. While it is expected that some proportion of the generation fleet will meet the technical requirements for PFR with minimal need for plant upgrades, this will not be the case for the entire generation fleet. The Commission notes that the minimum technical requirements for a generating system in relation to frequency control are set out in S5.2.5.11 of the NER, the existing minimum requirement for connection of a generator to the system is:

> (2) a *generating system* must be capable of operating in *frequency response mode* such that, subject to energy source availability, it automatically provides:
>
> > (i) a decrease in *power transfer* to the *power system* in response to a rise in the *frequency* of the *power system* as measured at the *connection point*; or
> >
> > (ii) an increase in *power transfer* to the *power system* in response to a fall in the *frequency* of the *power system* as measured at the *connection point*,

The Commission notes that the technical requirements for PFR proposed by AEMO in its draft PFRR document are much more specific and stringent than the existing minimum requirements for frequency control that apply for the connection of a generating system. The technical requirements for PFR are set out in AEMO's draft PFRR, which is summarised in section 4.1.1.

The Commission is interested in stakeholders providing estimates of the expected costs of any plant upgrades that would be required to meet the technical requirements set out in AEMO's draft PFRR. In order to better understand the existing frequency control capability of the generation fleet and the range of costs to provide narrow band PFR, the Commission invites stakeholders to provide information in relation to the existing frequency control capability of their plant and the scale of changes to generation plant that would be required in order to meet the technical requirements set out in AEMO's draft PFRR.[177]

177 Participants may request for information provided to the AEMC remain confidential. In the case of such a request, the Commission will not publish the related information.

6.2.3 Consideration of the cost benefit trade-off

While the benefits associated with the provision of narrow band PFR are difficult to quantify, there is likely to be a minimum set of technical requirements and a corresponding proportion of responsive generation where the operational needs of the power system are met. Beyond this point the incremental benefits of more stringent technical requirements or a larger proportion of the fleet being responsive are likely to diminish. At the same time, the incremental upfront costs of implementing a new mechanism for the provision of PFR are likely to increase as the technical requirements are strengthened or the proportion of the fleet that is responsive is increased.

While this cost benefit trade-off could be made dynamically through a more sophisticated policy mechanism, such as a new market or incentive based arrangement, the Commission recognises that there is an immediate need for improved frequency control in the NEM. It is not appropriate to continue to operate the NEM without effective frequency control during normal operation, and a regulatory change is now required to restore effective frequency control. As noted by AEMO, in its rule change request, *Mandatory Primary frequency response*, the implementation of this regulatory change cannot be delayed for a more sophisticated mechanism to be designed, trialled and implemented. [178]

In the absence of a mechanism that dynamically balances the costs of providing PFR with the benefits associated with the need for PFR, the Commission must consider how the settings in a proposed PFR mechanism reflect the long term interests of electricity consumers. In particular, the Commission will seek to develop a PFR mechanism to meet the immediate need for effective frequency control while limiting the costs associated with the implementation of such a mechanism to those costs that are necessary to meet the immediate system security need.

In its rule change request, *Mandatory primary frequency response*, AEMO recognises that there are likely to be some generating plant for which it is uneconomic to apply the mandatory requirement for PFR. AEMO's proposed rule, *Mandatory primary frequency response*, includes provision for AEMO to approve a variation or exemption for a generator in respect of any performance parameter for PFR. Under the proposed rule, AEMO will set out the conditions for granting such a variation or exemption in its PFRR.[179] AEMO's draft PFRR includes the following guidance in relation to AEMO's proposal to determine whether to grant an exemption for a particular generator in relation to the technical requirements for the provision of PFR:[180]

> If AEMO determines that the works proposed by an Affected Generator represent a significant uneconomic augmentation to the Affected Generator's plant, AEMO may grant the Affected Generator an exemption under section 6 for that plant.

178 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.43.

179 AEMO, Mandatory primary frequency response — draft rule, 16 August 2019, cl 4.4.2A(a)(iii).

180 AEMO, Primary frequency response requirements — draft, 16 August 2019, p.12.

In its rule change request, *Mandatory primary frequency response,* AEMO states that the optimal providers of PFR are the larger synchronous generating units in the NEM, particularly those with rated capacity in excess of 200MW. AEMO notes that:[181]

> The largest generating plants in the NEM have the greatest aggregate capability to deliver PFR to support the control of power system frequency, and increase the resilience of the power system to disturbances. Their unit size means they are capable of providing a larger absolute MW response to a disturbance. As they are typically online, they can also provide a response for the greatest number of hours a year.

However, AEMO's proposed rule, *Mandatory primary frequency response,* seeks to apply the obligation to be frequency responsive to all technically capable scheduled and semi-scheduled generation, including wind power and PV.[182]AEMO's intention in this proposed rule is that the PFR mechanism is technology neutral and that all capable plant contribute to power system frequency control.[183]

In assessing whether to make AEMO's proposed rule, *Mandatory primary frequency response,* or whether to make a preferred rule, the Commission will need to consider how best to balance the need for effective frequency control with the expected costs associated with upgrading generation plant to provide PFR in accordance with the technical requirements.

QUESTION 15: CONSIDERING THE COST BENEFIT TRADE-OFF FOR THE PROVISION OF PFR

In assessing the proposed rules for mandatory PFR, the Commission seeks stakeholder input on the following questions:

- What is the existing capability of the generation fleet to provide narrow band PFR?
- What is the scale and cost of plant upgrades that would be required to meet different PFR performance requirements, including the performance specifications set out in AEMO's draft PFRR?
- How much of the fleet must provide narrow band PFR in order to be confident that the immediate system security needs are satisfied?

181 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.30.

182 AEMO's draft PFRR includes a standing exemption for combined cycle gas turbine plant. The steam turbine component is not required to be frequency responsive. AEMO, Primary frequency response requirements — draft, 16 August 2019, p.10.

183 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.30.

7 LODGING A SUBMISSION

The Commission invites submissions on the rule change requests discussed in this consultation paper. Written submissions must be lodged with the Commission by 31 October 2019 online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0274.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions on rule change requests.[184] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Ben Hiron on (02) 8296 7800 or ben.hiron@aemc.gov.au.

184 This guideline is available on the Commission's website www.aemc.gov.au.

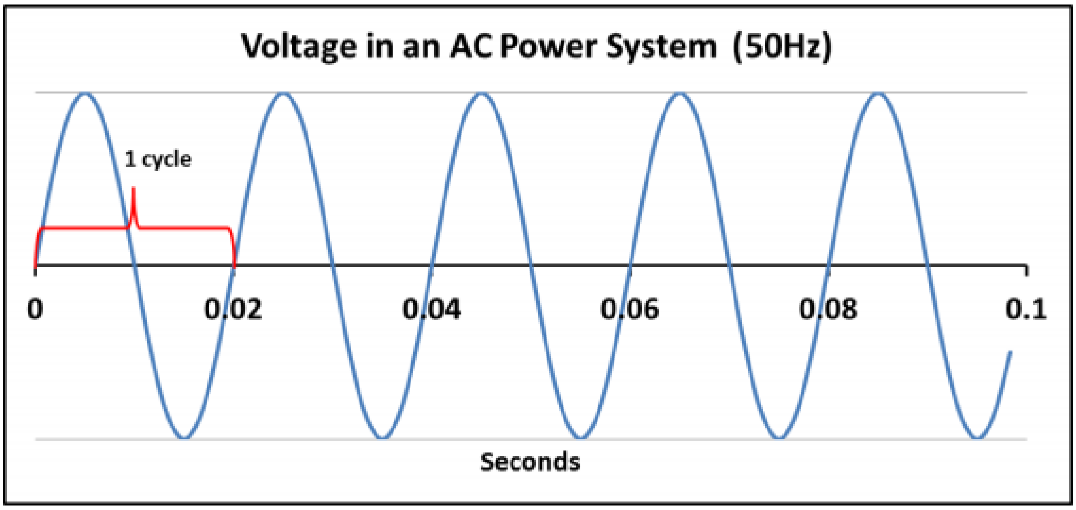
ABBREVIATIONS

AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic generation control system
Commission	See AEMC
Cl	Clause
DC	Direct current
DNSP	Distribution network service provider
DRP	Dispute resolution procedure
FCAS	Frequency control ancillary service
HILP	High impact low probability event
Hz	Hertz
MASS	Market ancillary service specification
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
NOFB	Normal operating frequency band (49.85 Hz — 50.15 Hz)
NSP	Network service provider
OFGS	Over frequency generation shedding scheme
PFR	Primary frequency response
TNSP	Transmission network service provider
UFLS	Under frequency load shedding scheme

A FREQUENCY CONTROL FUNDAMENTALS

The NEM, like most modern power systems, generates and transfers electricity via an alternating current (AC) power system. In an AC power system, alternating currents are accompanied (or caused) by alternating voltages. Voltage oscillates between negative and positive charge at a given rate. This can be represented by the following wave diagram, which shows how voltage shifts from positive to negative charge over a specific time frame. The number of complete cycles that occur within one second is called the "frequency" and is measured in Hertz (Hz). The voltage waveform corresponding to a frequency of 50 Hz is shown in Figure A.1.

Figure A.1: Voltage in an AC power system



Source: AEMC

In Australia all generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hz.

This frequency is directly related to the operation of generating equipment. Electricity in an AC system has historically been produced by large generators that rotate what is effectively a very large magnet within a coil of copper wire. This rotating magnet (called the rotor) induces a current to flow in the static coils (called the stator). The speed at which the rotor spins in the stator corresponds to how "quickly" the oscillations between positive and negative occur. Put another way, the frequency of an AC system corresponds to the speed of rotation of generators. Synchronous generators have rotors that are electro-mechanically coupled with the power system and spin at a speed that is proportional to the frequency of the power system.

Asynchronous generators, such as wind and solar plant, are connected to the AC system through power electronic devices that output an alternating voltage to match the frequency of the system. With the correct programming and plant capability, power electronics can cause a plant to respond to changes in system frequency but are not responsible for setting the nominal frequency of the system, in this case 50Hz for the NEM.

What is frequency variation?

The frequency in an operating power system varies whenever the supply from generation does not precisely match customer demand. Whenever total generation is higher than total energy consumption the system frequency will rise, and vice versa. This frequency variation is similar to how a car behaves when it begins to climb a hill after driving along a flat road. In order to maintain a constant vehicle speed as the car climbs the hill, the engine power must be increased to balance the increased "load" or the car will slow down. The engine power is increased by depressing the accelerator pedal, which supplies more fuel to the engine to maintain the vehicle speed.

In a similar way, power system frequency is affected by changes in customer demand, or load, relative to the amount of available generation. To maintain the "speed" — that is, the frequency — of the system following an imbalance of generation relative to load (analogous to the car beginning to climb the hill), more energy is required from generators (depressing the accelerator pedal) to maintain the system frequency at 50 Hz.

In the majority of situations, the changes in supply and demand that cause frequency variations are such that the corresponding variations in frequency are very small. Household appliances and industrial load being switched on and off are all examples of minor changes in demand happening all the time. The quantity of electricity supplied into the network may also change due to the variable output of wind and solar generation.

On occasion, changes in supply and demand can be more significant. Large generating units and transmission lines may trip unexpectedly and suddenly stop producing or transmitting electricity. Similar outcomes can occur on the demand side, if large industrial facilities trip off the system and suddenly stop consuming. These are referred to in the NER as contingency events. They are less common but tend to result in more significant changes in system frequency.

To maintain a stable system frequency close to the nominal system frequency, AEMO must balance the supply of electricity into the power system against consumption of electricity at all times. When there is more generation than load, the frequency will tend to increase. When there is more load than generation, the frequency will tend to fall. AEMO manages power system frequency by forecasting the expected load and issuing dispatch instructions to generators to meet that demand. The MW imbalance between supply and demand can occur at varying levels, be caused by a variety of factors, and occur over a variety of time frames. Causes include:

- Demand changing constantly within a dispatch interval, with both predictable and random components, over time frames of seconds to minutes.
- Demand forecasting errors, requiring correction over market dispatch time frames.
- Supply forecasting errors, such as:

- Forecasting inaccuracy in AWEFS, AEMO's wind energy forecasting system, as noted by DIgSILENT in a report prepared for AEMO and submitted to the AEMC during its *Frequency control frameworks review*.
- Unexpected changes in weather conditions impacting solar- or wind-dependent generation output, particularly changes inside the 5-minute dispatch cycle.

- Sudden contingency events, such as:
  - Tripping or disconnection of generation, load or transmission lines connecting them.
  - Simultaneous response of inverter-controlled plant to a change in power system conditions, such a fault or other system disturbance. This may occur at the distribution or transmission level.

A number of components of the regulatory framework enable AEMO to manage frequency. These include:

- **The frequency operating standard.** The frequency operating standard defines the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies.
- **Frequency control ancillary services (FCAS).** FCAS are procured by AEMO to increase or decrease active power over a time frame that meets the requirements of the frequency operating standard.
- **Generator technical performance standards.** The standards in the NER cover a range of technical capabilities for connecting generators, including frequency control and response to frequency disturbances during and following contingency events.
- **Emergency frequency control schemes.** Emergency frequency control schemes are schemes that help restore power system frequency in the event of extreme power system events, such as the simultaneous failure of multiple generators and/or transmission elements.

What are the consequences of frequency variation?

All equipment connected to the power system is designed to operate at or near the nominal frequency of 50Hz. For example, a typical steam turbine can operate continuously at ±1 per cent away from the nominal frequency, or within a range of 49.5-50.5Hz. Most consumer electronic equipment is designed to operate within a tolerance range of ±5 per cent away from the nominal frequency, or 47.5-52.5Hz. The tolerance of different machines or devices to frequency deviations varies both in terms of the size of a divergence that can be withstood and the length of time that the deviation can be ridden through. Large or lengthy deviations outside of these tolerance limits can increase wear and tear on this equipment, and could have significant impacts on its safety and functional efficiency. For example, steam turbines are generally only designed to withstand short periods of operation outside of its tolerance range, with a practical working limit reached at around ±5 per cent or 47.5-52.5Hz. The turbine may experience damaging vibrations outside this operating frequency range and, if allowed to operate at an excessively high speed, there is risk of a catastrophic equipment failure.

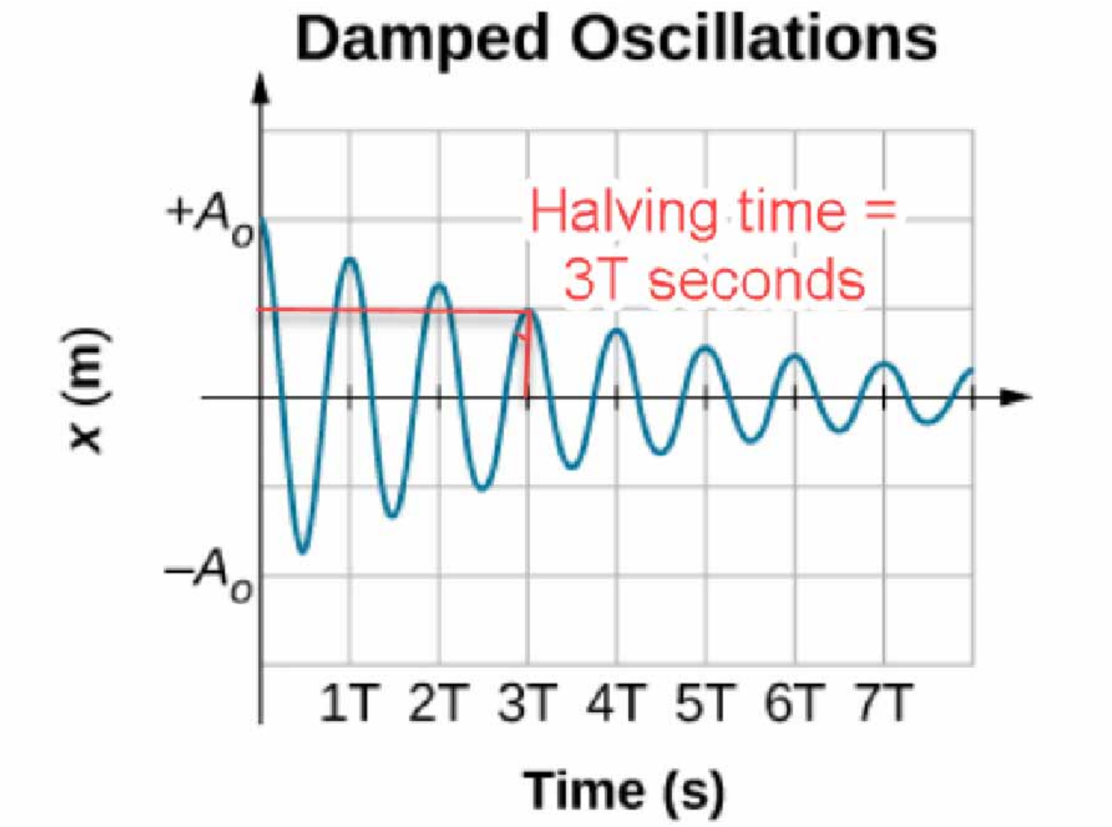
As a self-protection mechanism, generation and transmission equipment is designed to disconnect from the power system during periods of prolonged or excessive deviations from the nominal system frequency. However, the disconnection of generation due to low system frequency would worsen the supply-demand imbalance that originally caused the frequency disturbance and potentially lead to a cascading system failure and a major blackout. Controlling frequency is therefore critically important to maintaining a secure and reliable power system.

What is frequency stability?

Secure operation of the power system requires that frequency is stable during normal operation and following contingency events. Frequency stability is characterised as the ability of the power system to maintain or restore equilibrium between supply and demand and to avoid sustained, undamped oscillatory behaviour.

Frequency oscillations are repeated cyclical variations that can occur when the power system is not well controlled. Frequency oscillations can be mitigated, or damped, by generator control systems, causing the oscillations to decay and disappear over time. The extent to which an oscillation is damped is described by its 'halving time'. The halving time of a frequency oscillation is the time taken for the amplitude of the frequency oscillations to decrease to half their original magnitude, as illustrated in Figure A.2.

Figure A.2: The halving time of a damped oscillation



Source: AEMC

The criteria to be met by Network Service Providers for power system stability are described in S5.1.8 of the NER, including the extent to which frequency oscillations should be damped. The NER requires Network Service Providers to demonstrate that:

> there is less than a 10 percent probability that the halving time of the least damped mode of oscillation will exceed ten seconds, and that the average halving time of the least damped mode of oscillation is not more than five seconds.

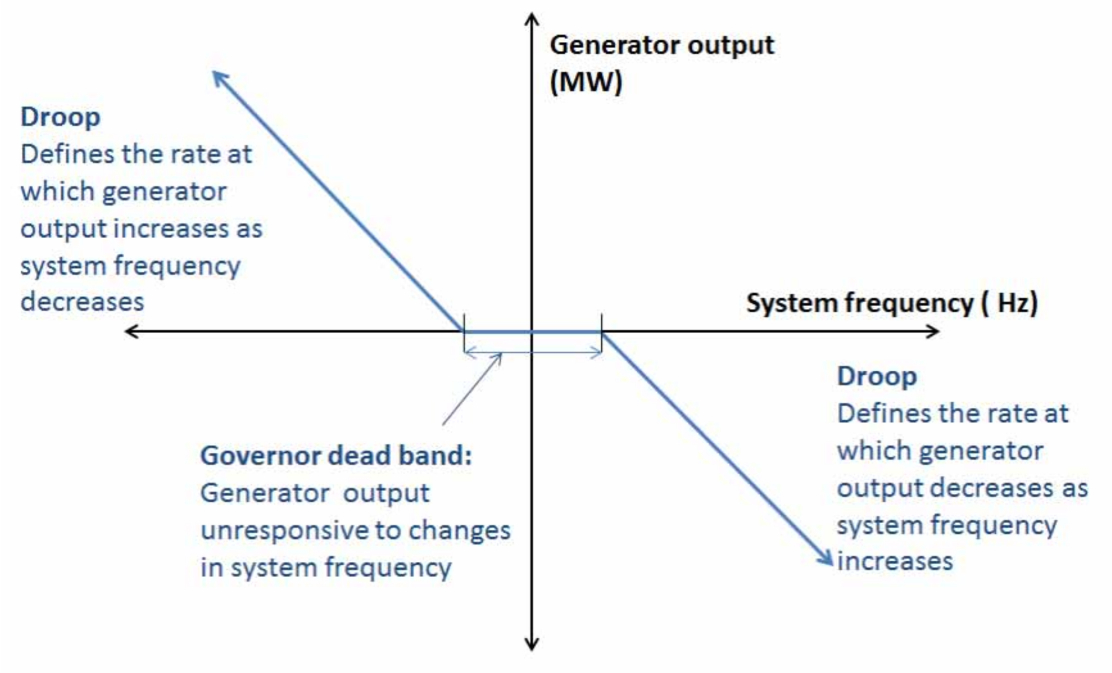
B AN EXPLANATION AND HISTORY OF GOVERNOR RESPONSE

What is governor response and what is its purpose?

A governor is a part of a generator control system that regulates the electrical output of a synchronous generating unit or generating system. In the context of frequency control, governors can be used to respond to frequency changes through changes in generating output.

Governors can be enabled to be automatically responsive to changes in the power system frequency outside of a pre-determined deadband. The deadband specifies the frequency range within which the governor is unresponsive to power system frequency changes, and within which the power output from the generator is kept steady, as shown in Figure B.1.

Figure B.1: Governor control of generator output



Source: AEMC

Droop is an indication of the change in generator output for a given change in power system frequency. Given a fall in power system frequency, the droop setting refers to the percentage frequency change that will result in the output of a generator increasing to 100 per cent of its rated capacity. For example given a 100 MW generator with a droop setting of 5 per cent and assuming that the generator is operating with sufficient headroom, a fall in power system frequency of 0.05 Hz or (0.1 per cent of 50 Hz) will result in an increase of power output from the generator of 2MW. Similarly, following an increase of power system frequency of 0.05 Hz the same generator would decrease its power output by 2MW.

Asynchronous generators are connected the power system and output their power through power electronic systems. Unlike synchronous generators, inverter connected asynchronous plant do not have physical governors to enable a frequency response. Instead, the frequency response of asynchronous plant is determined by the programming of it's power electronic systems, including its dead band and droop settings. These electrical controls can provide the same frequency response as that of physical governors described above.

History of governor control in the NEM

At the start of the NEM, in 1999, ancillary services were procured under the National Electricity Code through a tender process and long term contracts between NEMMCO and service providers.[185] [186] These contracts ensured the availability of the service (for instance, by ensuring that sufficient generators had "headroom" to provide a response above their dispatch targets), but all generators were mandated to provide a governor response to the extent that they were able to.

Following the Ancillary Service Review undertaken by NEMMCO in 1999, the ACCC provided authorisation for the creation of 8 ancillary service spot markets for the enablement of regulating and contingency FCAS.[187] In 2003, the requirements for mandatory generator governor response included in S5.2.6.4 of the National ElectricityCode was removed and replaced with S5.2.5.11, which set out the revised generator technical standards for frequency control.[188]

The removal of the requirement for mandatory response was not an inherent result of introducing FCAS markets — the spot markets for enablement simply replaced the previous contracting approach. It would have been possible to continue to impose the mandatory response obligation. However, in its review, NEMMCO recommended that this obligation be removed. The justification for this was that mandatory provision represented a "hidden subsidy" and that "governor capability should be fully paid for under the FCAS arrangements proposed".[189]

When the NEM began operation in 1998, all generating units over 100MW were obliged to have governors that responded to changes in system frequency outside of specified, relatively tight deadbands.

Prior to November 2003 the National Electricity Code included a requirement mandating that generators have an operational governor system that automatically responded to frequency. This "governor system" requirement, set out in schedule 5.2.6.4 of the code, was removed in

185 The National Electricity Market Management Company (NEMMCO) was a predecessor to AEMO

186 NEMMCO, *Ancillary Service Review — Recommendations*, Final Report, 15 October 1999, p. i.

187 ACCC, *National Electricity Code — Ancillary services amendments,* determination, 11 July 2001, p.38.

188 NECA, Technical standards code changes gazetted 27 March 2003. S5.2.6.4 deleted and replaced with S5.2.5.11.

189 Intelligent Energy Systems, *Who should pay for ancillary services?*, A project commissioned by the NEMMCO ancillary services reference group, Final report, July 1999, p. 48.

November 2003 and replaced with automatic and minimum access standards that require generators to have the capability to respond to frequency disturbances.[190]

The mandatory governor system requirement applied to all generating units with a rated capacity of 100MW and above. The requirement specified key performance criteria relating to the governor responses, which are set out below.[191]

BOX 4: TECHNICAL PERFORMANCE REQUIREMENTS OF GOVERNOR SYSTEMS UNDER THE NATIONAL ELECTRICITY CODE PRIOR TO 16 NOVEMBER 2003

- The response of the generating unit to system frequency excursion should be capable of:
  - Achieving an increase in the generating unit's active power output of 2% per 0.1 Hz reduction in system frequency for any initial output up to 85% of rated output
  - A reduction in the generating unit's active power output of 2% per 0.1Hz increase in system frequency provided the latter does not require operation below technical minimum.
- Generating units must be capable of achieving an increase in output of at least 5% of their rating for operation below 85% of output. For operation above 85% of rated load, the required increase will be reduced linearly with generating unit output from 5% to zero at rated load. The generating unit will not be required to increase output above rated load.
- Generating units must be capable of achieving a decrease in output of at least 10% of their rating for operation at all levels above their technical minimum loading level as advised in the registered bid and offer data.
- The deadband of a generating unit (being the sum of the increase and the decrease in system frequency before a measurable change in the generating unit's active power output occurs) must be less than 0.1 Hz.
- For any frequency disturbance a generating unit must be capable of achieving at least 90% of the maximum response to power generation expected according to the droop characteristic within 60 seconds and sustain the response for a minimum of 30 seconds.
- When a generating unit is operating in a mode such that it is insensitive to frequency variations (including pressure control or turbine follower for a thermal generator), the Generator must apply a deadband of not greater than 0.25 Hz to ensure that the generating unit will respond for frequency excursions outside the normal operating frequency band.

Source: AEMC

190 NECA, 2003, *Technical standards code changes,* Gazette notice, S5.2.11, 27 March 2003 The automatic and minimum access standards set out in S5.2.5.11 of the code version 1.0, amendment7.7 form the basis of the current S5.2.5.11 in the NER.

191 Ibid., S5.2.6.4.

C NOTES ON NON-CONTROVERSIAL RULES

Under S96 of the NEL, The Commission may determine that a rule change request is a request for a non-controversial rule if the rule change is unlikely to have a significant impact on the national electricity market. Previous examples of non-controversial rules have involved administrative changes to the NER in relation to process time frames, task responsibility assignment or simply textual error correction. If any proposed rule change is likely to impact the way market participants behave in the market or operationally in the NEM, particularly in any way that significantly affects the costs of any individual participants, the Commission will not consider this to be a request for a non-controversial rule.

When the AEMC considers whether to process a rule change request as a request for a non-controversial rule, it is important to note that:

1. It is the intent of the proposed rule that is assessed, not the form of the drafting. A rule can be re-drafted to mitigate any unintended consequences of its implementation, but only a rule that does not intend to impact the financial, operational and/or practical behaviour of the NEM can be considered non-controversial.
2. The definition national electricity market which is referred to in the definition of non-controversial rule includes both the wholesale market operated by AEMO and the national electricity system.
3. The terms 'unlikely' and 'significant' are to be read using their natural meaning and it is ultimately the AEMC's discretion to interpret these words with respect to a rule change request on a case by case basis.
4. The AEMC has discretion to progress a rule change proposal under the standard process even where a rule change meets the test for a non-controversial rule.
5. Even when the AEMC initially considers a rule change to be non-controversial, the NEL provides an opportunity for parties to request that the rule change not be treated as expedited. If that request is not misconceived or lacking in substance, the rule will be assessed via standard rule change process.

The following provides a summary of recent non-controversial rules as a reference:

Intervention compensation and settlement processes Rule 2019

The issues raised by AEMO in this rule change request primarily related to changes to the deadlines for additional compensation claims following market intervention and the alignment of intervention compensation and settlement timetables.

The Commission considered that the rule change request was unlikely to result in a significant impact on the NEM as the issues raised in the rule change request represented procedural changes and were administrative in nature. The proposed changes were not expected to result in significant additional costs to consumers or changes in the allocation of costs to market participants.

Application period for contingent project revenue rule 2019

The proposed rule allowed transmission and distribution network businesses to submit a contingent project application at any time during a regulatory control period up until the last 90 business days of the penultimate year of the regulatory control period.

The Commission considered that the proposed rule was administrative in nature as it related to the timing for the submittal of a contingent project application. The proposed rule would not affect the amount an NSP could recover nor when an NSP could recover incremental revenues approved in respect of a contingent project. Rather, the rule would bring forward the AER consideration and approval of a contingent project by three to four months if it was submitted in the last 90 business days of a regulatory year.

D NOTES ON FREQUENCY CONTROL AND COMPLIANCE WITH DISPATCH INSTRUCTIONS

Some stakeholders are of the view that the deterioration in frequency performance is (either partially or entirely) a result of generators reducing or removing their responsiveness to frequency deviations in the NOFB to 'prioritise' compliance with clause 4.9.8(a) of the NER. Clause 4.9.8(a) of the NER states that: "A Registered Participant must comply with a dispatch instruction given to it by AEMO unless to do so would, in the Registered Participant's reasonable opinion, be a hazard to public safety or materially risk damaging equipment." This clause is a civil penalty provision.

Over the lifetime of clause 4.9.8(a) of the NER, the AER has issued five infringement notices for failure to comply with dispatch instructions, and has instituted proceedings in the Federal Court once (successfully) against Snowy Hydro for a number of breaches of this clause.[192] In its December 2016 quarterly compliance report, the AER stated that compliance with dispatch instructions is a priority area.

In the report prepared for AEMO in September 2017, DIgSILENT reported that "there appears to be a heightened awareness of … compliance with dispatch instructions" as a result of the AER's actions in this area. DIgSILENT noted that some participants believe they are better able to achieve dispatch compliance if they do not have their governors responding to frequency variations.[193] Similarly, DIgSILENT reported that there is a strong belief that adhering closely to dispatch targets will minimise a participant's contribution factors, which are used to determine the allocation of regulating FCAS costs. DIgSILENT concluded that these perceptions, in combination with the fact that there is no obligation for a generator to provide it, may be a contributing factor in the withdrawal of governor response.

The AER is responsible for monitoring compliance with the NER, including clause 4.9.8(a), and taking action where it deems necessary. To explain further its approach to monitoring compliance with the rules, the AER published a Compliance and enforcement statement of approach. This document sets out, amongst other things, the AER's objectives for enforcement and the factors and circumstances it takes into account in deciding to take any enforcement action. These factors include (amongst others):

- the nature and extent of the conduct that forms the breach
- the impact of the conduct
- whether the conduct was deliberate or avoidable had reasonable compliance practices been followed by the business
- the extent of any financial gain
- the business's own actions in relation to the conduct.

192 Clause 4.9.8(a) of the NER was in version 1 of the NER and was also included in the NationalElectricity Code, which pre-dated the NER.

193 DIgSILENT, *Review of frequency control performance in the NEM under normal operating conditions*, 19 September 2017, p. 7.

In its Compliance and enforcement statement of approach, the AER states that civil proceedings are more likely to be initiated when the conduct:

- resulted in significant detriment
- demonstrated a blatant, ongoing or serious disregard for the law
- is that of a person, business or sector that has a history of previous breaches.

E INTERNATIONAL APPROACHES TO PFR

The below table summarised the market mechanisms and technical parameters different jurisdictions use internationally to procure PFR in their respective power systems.

Table E.1: **Table F.1 International approaches to procuring PFR**

JURISDICTION	PROCUREMENT MECHANISM	DEAD-BAND (HZ)	DROOP
Australia - NEM[1]	Real time market (Capacity)	±0.150 for generators who chose to participate in FCAS markets ±1.000 for other generation	N/A
Australia - WEM[2]	Mandatory – Unpaid (response) Bilateral contract (Capacity)	±0.025	4%
Argentina[3]	Mandatory – Unpaid (response) (3 per cent reserve capacity) Real time market (response)	±0.150	N/A
Brazil[4]	Mandatory - Unpaid (response)	±0.040	2-8%
Belgium	Mandatory – Unpaid (response) Bilateral contract (Capacity) Public tender (Capacity)	N/A	N/A
Czech Republic	Public tender (Capacity)	0.000	8%

JURISDICTION	PROCUREMENT MECHANISM	DEAD-BAND (HZ)	DROOP
Finland	Mandatory – Paid (Capacity)	±0.100	2-12%
France	Bilateral contract (Capacity)	±0.001	N/A
Germany	Public tender (Capacity)(monthly)	±0.020	4-8%
Switzerland[5]	Public tender (Capacity)(weekly)	±0.010	2-12%
Ireland	Mandatory – Paid (response) (regulated tariff)	±0.015	3-5% for synchronous generation 4% for wind generation (adjustable between 2-10%)
New Zealand	Bilateral contract (Capacity)(lower reserve) Real time market (Capacity) (regulation and raise reserve)	None specified	0-7%
Spain	Mandatory – Unpaid (Capacity and response)	±0.000	As instructed by ISO
UK (England and Wales)[6]	Mandatory – Paid (Capacity and response) Bilateral contract (Capacity and response)	±0.015	3-5%
USA (California) - Western Interconnection	Public tender (Capacity)	±0.036	4% droop (gas turbine), 5% droop (all others)
USA (Texas) - ERCOT[7]	Mandatory – Unpaid (response) Bilateral contract (Capacity)	±0.034 for steam/hydro with mechanical	4% for combustion 5% for all other generation

JURISDICTION	PROCUREMENT MECHANISM	DEAD-BAND (HZ)	DROOP
		governor ±0.017 for all other generation	
Ontario[8]	Mandatory – Unpaid (response) Real time market (Capacity)	±0.036	4% (adjustable between 2-7%)
Singapore[9]	Mandatory – Unpaid (response) Bilateral contract (Capacity)	±0.050	3-5%

Source: AEMC, *Frequency control frameworks review*, Issues paper, 7 November 2017, pp.65-67

Note: [1] AEMO, *Mandatory primary frequency control* - Electricity rule change proposal, 16 August 2019, p.35
[2] Ibid.
[3] In the Argentinian power system, generators that offer more than 3 per cent frequency response capacity during real time market operation may receive more income, while those that offer less than 3 per cent are required to pay to the other generators for the additional reserve. ref: CAMMESA, Los Procedimientos - Anexo 23 - 3.2
[4] FERC, *Review of International Grid Codes*, February 2018
[5] Ibid.
[6] The UK national grid pays frequency response service providers a holding payment in £/hr and an energy payment in £/MWhr. Large generators over 100MW and medium generators over 50MW that are connected to the transmission system must provide the frequency response service. Other generators may request to provide the frequency response service by agreement with National Grid. National Grid, 2013, Mandatory Services - Frequently asked questions, version 1.0, May 2013, p.7.
[7] NERC, Ancillary Service andBalancing Authority Area Solutions toIntegrate Variable Generation, 2011 March, p.21
[8] Ibid.
[9] FERC, *Review of International Grid Codes*, February 2018

F DESCRIPTION OF THE MANDATORY FREQUENCY RESPONSE ARRANGEMENTS USED IN THE UK NATIONAL GRID

In the UK grid, mandatory frequency response (MFR) is a service that is procured by the grid operator, National Grid ESO, to provide continuous automatic narrow band frequency response to help control the power system frequency. MFR provides an automatic change in active power output via a generator governor system in response to a frequency change outside of a set frequency deadband. This response is proportional to the change in frequency (known as 'droop response', which must be in the range of 3 — 5%) and the deadband must not be wider than ±0.015Hz.[194]The UK grid code sets out three types of frequency response that can be provided to satisfy the MFR obligation.[195]

1. Primary response — provision of additional active power (or a decrease in demand) within 10 seconds after an event and can be sustained for a further 20 seconds.
2. Secondary response — provision of additional active power (or decrease in active power demand) within 30 seconds after an event and can be sustained for a further 30 minutes.
3. High frequency response — the reduction in active power within 10 seconds after an event and sustained indefinitely.

The capability to provide MFR is a condition of connection for all generators over a certain registered capacity, depending on the transmission network. The threshold for MFR capability is 100MW for connection to the National Grid, 10MW for Scottish Hydro Electricity Transmission or 30MW for Scottish Power.[196]

When a generating unit is built or modified, its capability to provide MFR is tested and documented through a contract known as a mandatory service agreement.[197] The grid operator, National Grid, may then instruct generators to operate in a frequency sensitive mode to provide frequency response in accordance with their ancillary service agreement. Generators who are instructed to operate in a frequency sensitive mode are compensated through a generator-nominated holding payment (in £/hour) for being available to provide MFR and a response energy payment (£/MWh) for the amount of energy delivered through provision of the frequency response service.[198]

The MFR service provided into the UK national grid does not explicitly require service providers to maintain headroom capacity in order to provide MFR, although there are related arrangements that manage the need for response headroom and compensate Generators accordingly. If the generator does not have sufficient headroom (based on their physical nomination of active power capacity that they nominate for the next settlement period) then the System Operator must pay to reposition them to an appropriate part-load point so that

194 UK Grid Code, CC.6.3.7(c)(iii)

195 UK Grid Code, GD.1.

196 National Grid, Mandatory Frequency Response, version 1.1.

197 National Grid, Connection and Use of System Code, clause 1.3.3.

198 National Grid, Connection and Use of System Code, clause 4.1.3.8.

the generator can provide the required frequency response. These payments are made via a separate balancing mechanism and the associated repositioning costs of are taken into account when deciding which generators to instruct for MFR.[199]

199 National grid, GC022 — FrequencyResponse — Working group report, 9 January 2013, p.17.