RULE

Australian Energy Market Commission

RULE DETERMINATION

# NATIONAL ELECTRICITY AMENDMENT (MANDATORY PRIMARY FREQUENCY RESPONSE) RULE 2020

**PROPONENTS**

AEMO
Dr. Peter Sokolowski

26 MARCH 2020

## INQUIRIES

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## ABOUT THE AEMC

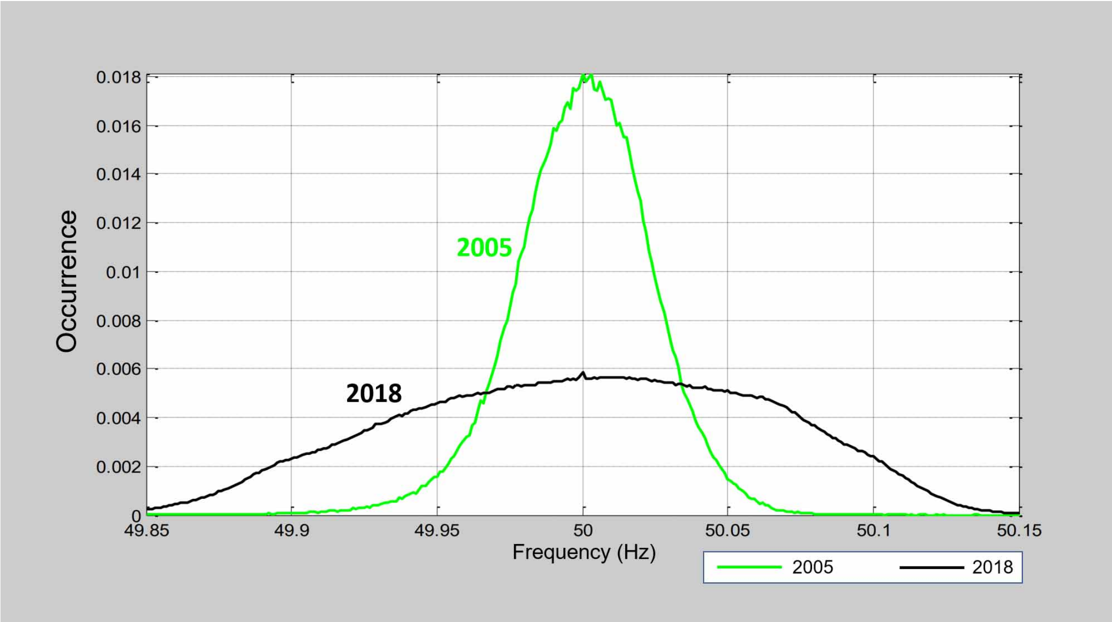
The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

# EXECUTIVE SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has made a more preferable final rule to require all scheduled and semi-scheduled generators in the National Electricity Market (NEM) to support the secure operation of the power system by responding automatically to changes in power system frequency. An increase in the provision of primary frequency response (PFR) from generators will improve the security of the national electricity system for the benefits of consumers and will give the Australian Energy Market Operator (AEMO) greater confidence that it is maintaining the power system in a secure operating state.

2 The Commission concluded in its 2018 *Frequency control frameworks review* that frequency performance under normal operating conditions had been declining in recent times and that changes to the existing frameworks were required to support effective frequency control in the national electricity system. 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. Frequency distributions for the mainland and Tasmania have been moving increasingly further away from 50 Hz than has historically been the case.

**Figure 1: Frequency distribution within the normal operating frequency band in the NEM (2005 snapshot v 2018 snapshot)**




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

3 Historically in the NEM, only synchronous generators, such as coal, gas and hydro, have provided PFR. However, non-synchronous 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.

4 The Commission considers that a rule that introduces a mandatory requirement for generators to activate an existing capability to provide PFR is likely to address the immediate need identified by AEMO for improved frequency control in the NEM. However, the Commission recognises that a mandatory requirement for narrow band PFR is not a complete solution and, on its own, will not incentivise the provision of primary frequency response. The Commission considers that further work needs to be done to understand the power system requirements for maintaining good frequency control including building on AEMO's work in the *Renewable Integration Study*.[1] This future work will also consider the appropriateness of the mandatory requirement for narrow band PFR and other alternative and complementary measures, including the potential for new market and incentive-based mechanisms for frequency control, which will occur through the Commission's assessment of the *Removal of disincentives for the provision of Primary frequency response* rule change request as well as any other relevant rule change requests received.

5 This approach is consistent with the frequency control work plan that was set out in the Commission's 2018 *Frequency control frameworks review* which identified a need to reform the frequency control arrangements in the NEM to keep pace with technological change. The Commission's final report for the review recommended the implementation of interim arrangements, if required, along with the development of frameworks to incentivise the provision of sufficient PFR over the long term to support good frequency performance during normal operation.

6 The final rule includes a sunset on the mandatory PFR requirement three years in the future on 4 June 2023. The inclusion of the sunset demonstrates the Commission's commitment to the implementation of further reforms prior to June 2023 to appropriately value and reward the provision of frequency control services. This final determination includes a revised frequency control work plan developed in collaboration with the ESB and other market bodies, which sets out a pathway to the development of future arrangements to appropriately incentivise and reward frequency control in the NEM. The AEMC will continue to work with the ESB, and other market bodies on these matters, and will give further consideration to the sunset through the *Removal of disincentives for the provision of PFR* rule change request as well as any other relevant rule change requests received.

**7 The final rule**

8 The Commission’s final rule has been made with respect to two rule change requests; one received from AEMO and another from Dr. Peter Sokolowski. Each of these requests proposed to mandate that all capable scheduled and semi-scheduled generators be operated to

1 AEMO, 2019, *Maintaining Power System Security with High Penetrations of Wind and Solar Generation: International insights for Australia*, published October 2019. Accessed at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/future-grid/renewable-integration-study

respond to changes in the locally measured power system frequency, albeit through different proposed changes to the National Electricity Rules (NER).

9 As the scope of these two rule change requests cover similar and related matters, the Commission consolidated these requests in December 2019 and has published a single final determination and final rule.

10 The final rule places an obligation on all scheduled and semi-scheduled generators, who have received a dispatch instruction to generate to a volume greater than 0 MW, to operate their plant in accordance with the performance parameters set out in the *Primary frequency response requirements* (PFRR) as applicable to that plant. AEMO is responsible for system security and the operation of the power system and so would also be responsible for the development of the PFRR, in consultation with market participants.

11 The final rule introduces a new *primary frequency control band* of 49.985 Hz to 50.015 Hz, which sets a lower bound on the deadband to which individual generators must comply under the conditions of the PFRR. The Commission considers that the *primary frequency control band* is a key variable associated with the final rule, which has implications for both system operation, as well as the operation of the markets for electricity and ancillary services in the NEM. In the absence of a clearly defined frequency performance standard in the frequency operating standards, the Commission has determined that the lower bound for the *primary frequency control band* be specified in the NER, and not subject to full discretion by AEMO in the PFRR.

12 The Commission considers this immediate change to the NER is justified by the need to improve and maintain the security and resilience of the national electricity system to meet AEMO's concerns. AEMO's view is that all of the generation fleet needs to provide primary frequency response in order to be effective in managing system security.

13 The Commission has also specified in the final rule that the PFRR cannot require generators to maintain additional headroom or stored energy for the purposes of providing frequency response in accordance with the requirements of the PFRR.[2] The Commission acknowledges that AEMO did not propose to include a requirement in the PFRR that generators maintain headroom as part of its proposed rule. However, the PFRR is subject to change, and any future obligation which results in a large cross-section of the generating fleet maintaining headroom would likely impose substantial costs on generators that outweigh the additional benefits this might provide to the security of the power system. This aspect of the final rule provides greater clarity and certainty to generators and will limit the likelihood of substantial unwarranted costs being incurred by generators in the future.

14 The Commission has considered submissions from stakeholders in response to the draft

2 Available headroom for frequency response refers to the capacity for a generator to raise its generation output in response to a drop in system frequency. It is dependent on the generating level of the plant based on market dispatch along with energy source availability and plant operating limits. Unless curtailed due to system constraints, semi-scheduled generators such as solar and wind power stations typically do not maintain stored energy or headroom, as their generation output is limited by the energy availability of the wind or sun. On the other hand, scheduled generators including thermal, hydro and batteries typically operate with some level of stored energy availability which varies by plant type. Scheduled generators maintain stored energy for a range of reasons, including maintaining a minimum ramp rate capability and in accordance with being enabled in the market for provision of frequency control ancillary services.

determination published on 19 December 2019. The Commission's final rule makes some changes with respect to the conditions to be agreed between AEMO and generators for the provision of PFR in response to this feedback. As part of meeting the requirements of the PFRR, generators will be required to provide a frequency response to a deadband no narrower than the primary frequency control band. However, other response characteristics such as droop and response time will only be specified by AEMO as part of the requirements if practical to do so. These additional characteristics may depend on the availability of stored energy in the energy system and, in the absence of available stored energy, it may be difficult for a generator to commit to a specific droop or response time and to verify compliance against such performance parameters. Therefore, in the final rule AEMO is provided with adequate guidance on the primary frequency response parameters to be included in the PFRR. At the same time, AEMO has increased flexibility as to how it specifies these parameters.

15 In response to stakeholder concerns made on the draft rule, the final rule also provides that the PFRR must not require the installation or modification of monitoring equipment to monitor and record the response of the relevant generating system to changes in power system frequency for the purpose of verifying compliance with the mandatory PFR requirement. The final rule does require, including consulting with industry, AEMO to document the details of the information to be provided by Generators to verify compliance with the PFRR, including any compliance tests or audits and testing requirements for the purpose of verifying compliance through its PFRR.

**16 Exemptions**

17 The final rule includes a requirement for AEMO to develop and publish the PFRR to specify the performance parameters that apply to generators in respect of the provision of PFR. The final rule requires that the PFRR includes provision for generators to request, and AEMO approve, an exemption or variation from the requirements specified by AEMO in the PFRR applicable to their generating system. The final rule sets out a series of principles to guide AEMO in considering any such requests.

18 The Commission has made some changes to these principles from those included in the draft rule in response to stakeholder submissions. The changes are intended to provide greater clarity on how AEMO should assess generator revenue and costs to determine variations and exemptions.

19 The Commission expects that the costs for existing generators to meet the performance parameters for PFR will vary. Some plant connected prior to 5 October 2018 may require significant plant upgrades and control system tuning in order to provide PFR in accordance with the performance parameters.[3] The exemption framework introduces a degree of flexibility that avoids excessive compliance costs for eligible generation plant while still delivering on AEMO's system security and frequency control objectives.

3 The 2018 *Generator technical performance standards* rule introduced changes to the NER that included a requirement for connecting generators to be capable of operating in a frequency response mode. This rule commenced on 5 October 2018. The Commission expects that most generators who connect to the NEM after 5 October 2018 will be capable of complying with the final rule — *Mandatory primary frequency response*.

**20 Implementation**

21 The commencement date for the rule is 4 June 2020. The transitional rules require that AEMO prepare an interim PFRR to apply from the commencement date. The interim PFRR will document AEMO's process for coordinating changes to generation plant associated with the activation of the frequency response mode. This process includes a requirement for AEMO, in coordination with each generator, to specify a date, following the commencement date of the rule, by which time the generator must comply with the performance parameters set out in the PFRR. AEMO is required to consult with stakeholders prior to publishing the interim PFRR by the commencement date of the rule.

22 AEMO's proposed rule included transitional arrangements for generators to submit a claim for reimbursement of costs associated with plant upgrades to become compliant with the PFRR.

23 Consistent with the draft rule, the Commission's final rule does not include any transitional arrangements for affected generators to be directly reimbursed for plant upgrade costs. Compensation is not typically provided to affected parties for the costs associated with complying with an amendment to the NER. Furthermore, the costs for plant upgrades and control system changes are expected to be relatively minor and manageable for most affected generators. Where the costs of plant upgrades would be more substantial, it is intended that a generator will be eligible for a full or partial exemption from the requirement which will avoid or reduce the upfront costs.

**24 Sunset to the rule and forward work plan**

25 In the context of the full range of solutions identified through the *Frequency control frameworks review* to improve frequency control during normal operation, the Commission considers that the mandatory PFR requirement is a transitional arrangement that is only acceptable in isolation for an interim period. The Commission is mindful of the costs that such a mechanism, on its own, would impose on generators. While a mandatory approach may be necessary in the interim in order to meet immediate system security needs, it would be preferable for this approach to be complemented by incentives and rewards for providing frequency response. Stakeholders have expressed broad support for the development of mechanisms that create efficient incentives for investment in and operation of plant to provide PFR. However, given the time needed to develop such arrangements, the Commission considers that it is not possible to implement an effective incentive arrangement at the same time as addressing the immediate system security needs.

26 Additionally, the Commission is aware of stakeholder concerns in relation to the potential for the mandatory PFR requirement to dampen the available incentives for providing frequency control through the markets for Frequency control ancillary services (FCAS). While AEMO has indicated that it does not intend to reduce the quantity of contingency reserve services that it procures as a consequence of this rule, it is expected that the mandatory PFR requirement will drive increased participation in the FCAS markets, which will increase competition and put downward pressure on prices for these services. The Commission recognises that the evolution of the FCAS markets has not kept pace with the system requirements for frequency control and that the implementation of mandatory PFR is now required to support the secure operation of the power system. The Commission considers that further work needs to be

done to understand the power system requirements for maintaining good frequency control and to reform the existing frequency control frameworks to meet these needs now and in the future.

27 Therefore, the final rule includes provision for a sunset after a period of three years. The sunset provision in the final rule is a clear signal that the Commission is committed to developing incentive arrangements for primary frequency response prior to June 2023, which will occur through the *Removal of disincentives for the provision of PFR* rule change request as well as any other relevant rule change requests received.

28 To reflect this commitment to the ongoing reform of the frequency control frameworks, the AEMC, in collaboration with the ESB and other market bodies, has developed a revised *Frequency control work plan*. The revised work plan is based on the plan published at the end of the *Frequency control frameworks review* in July 2018 and provides an update on progress to date on key actions along with an indication of the next steps in the reform pathway for frequency control frameworks in the NEM. In response to stakeholder feedback, the work plan has been updated to provide more detail.

29 Once arrangements are in place to address the immediate system security concerns, the ESB, AEMO, the AER and the AEMC will be better placed, in terms of time frames and flexibility, to further develop new approaches to frequency control and PFR. The Commission considers that three years is adequate time to determine and implement arrangements that incentivise frequency control in the NEM.

30 The consideration and implementation of incentive arrangements will be considered through the assessment of AEMO's remaining rule change request, *Removal of disincentives to primary frequency response* and any other related rule change requests received. AEMO's rule change request identifies issues in the NER that relate to the existing incentive arrangements for market participants to help to control system frequency during normal operation. In December 2019, the Commission extended the time frame for the publication of a draft determination with respect to this rule change request until September 2020.

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## FIGURES

# 1 THE RULE CHANGE REQUESTS

## 1.1 The rule change requests

The Australian Energy Market Commission (AEMC or Commission) has made a final rule that places an obligation on all scheduled and semi-scheduled generators to provide primary frequency response (PFR). The obligation to provide PFR must be met in accordance with technical criteria to be developed by the Australian Energy Market Operator (AEMO) and set out in its *Primary frequency response requirements* (PFRR) document. AEMO is responsible for the development of the PFRR in consultation with market participants.

The Commission has made this final rule based on advice from AEMO, supported by expert advice from Dr John Undrill, that this reform will meet the immediate system need for effective frequency control in the NEM. However, the Commission also considers that further reform will be needed in the future as the nature of primary frequency response capability in the NEM changes over time due to the changing generation mix, including the transition towards more variable and distributed forms of energy generation. As such, the final rule includes a sunset period of three years to provide time to develop and implement an approach that achieves the system security objectives outlined by AEMO but does so in a way that also provides effective incentives for participants to provide primary frequency response. Prior to the sunset ending, the Commission will have considered how to incentivise primary frequency response through the assessment of separate rule change requests (discussed below).

The AEMC received two rule change requests proposing the mandatory provision of primary frequency response from scheduled and semi-scheduled generators in the NEM: one from AEMO and one from Dr. Peter Sokolowski.

- ERC0274 — *Mandatory primary frequency response*, submitted by AEMO on 16 August 2019,
- ERC0277 — *Primary frequency response requirement*, submitted by Dr. Peter Sokolowski on 30 May 2019.

Each of these rule change requests proposed changes to the National Electricity Rules (NER) to introduce a mandatory obligation for all scheduled and semi-scheduled generators in the National Electricity Market (NEM) to control power system frequency. The proposed requirement would require eligible generators to vary the power they deliver to the grid whenever the system frequency moves outside of narrow frequency band close to 50Hz. The rule change requests also proposed related changes to the regulatory arrangements that are intended to improve frequency control and system security in the national electricity system.

As the scope of these two rule change requests cover similar and related matters, the Commission determined in December 2019 to consolidate these rule change requests under section 93 of the National Electricity Law (NEL). The Commission has published a single final determination and final rule with respect to these consolidated rule change requests.

The AEMC also received a second rule change request from AEMO on 3 July 2019 which relates to incentive arrangements for the provision of primary frequency response. In

December 2019, the Commission extended the time frame for making a draft determination with respect to AEMO's rule change request, R*emoval of disincentives to primary frequency response,* until 24 September 2020 to allow for further consideration of the incentive arrangements under the NER for frequency response during normal operation. The Commission considers that further refinements to the NER in relation to valuation and remuneration of frequency response as well as further consideration of the sunset should occur through the assessment of AEMO's second rule change request as well as any other relevant rule change requests received.

## 1.2 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.

This degradation of frequency performance was investigated by the Commission through the *Frequency control frameworks review* which concluded in July 2018. The Commission concluded that frequency performance under normal operating conditions had been deteriorating and that changes to the existing frameworks were required to support effective frequency control in the national electricity system. During the *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.*

The AEMC's final report therefore did not recommend any regulatory change in the immediate term to address the deterioration, but concluded that there is a need to find a more permanent solution to the issue and set out a number of options for further development. 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.

The following sections provide an overview of the recent degradation of frequency performance in the NEM and an introduction to the key concepts relating to frequency control and primary frequency response.

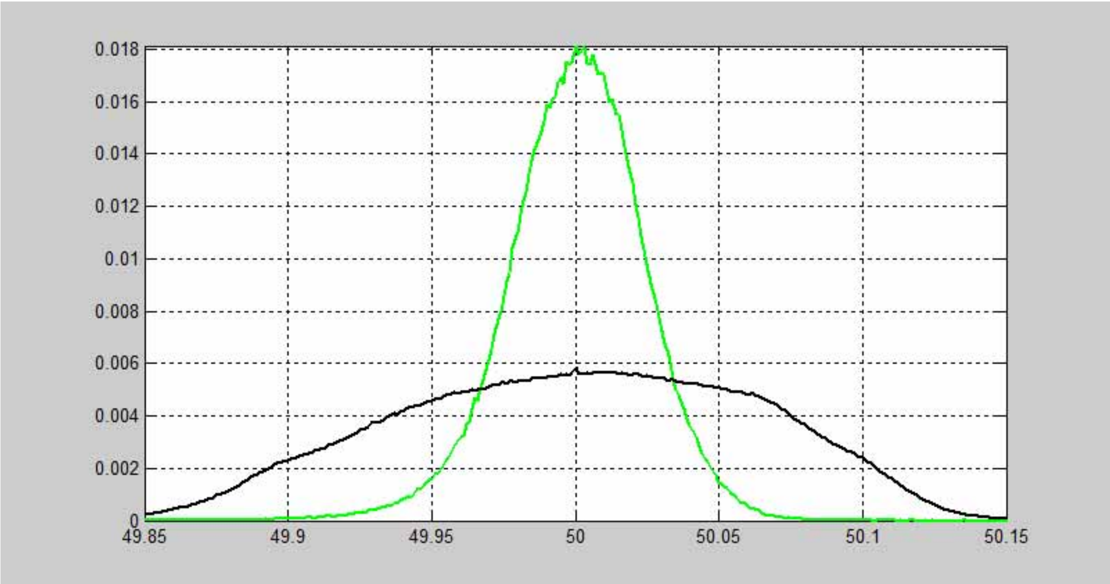
### 1.2.1 Recent degradation of frequency performance in the NEM

As noted above, 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.[4]

4 AEMO, Mandatory primary frequency response - Electricity rule change proposal, 16 August 2019, p.17-18.

Figure 1.1 shows that the frequency distributions for the mainland and Tasmania are increasingly further away from 50 Hz than has historically been the case.

**Figure 1.1: 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, black line shows 2018 data.

AEMO has also reported an increased incidence of exceedance events, where the power system frequency falls outside the normal operating frequency band (NOFB). Many of these excursions have occurred under normal operating conditions in the absence of a contingency event.

There are risks and costs associated with the power system operating more often at frequencies at the edges of the NOFB. Some of the consequences of deteriorating frequency performance 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
- increase in regulating FCAS costs

- possibility of further withdrawal of PFR due to the added burden on existing PFR.

AEMO also highlights that high variability in system frequency makes it more difficult for the Frequency Operating Standard to be met. In addition, it impedes AEMO's 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.

### 1.2.2 Frequency control and primary frequency response

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.

#### 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 change in system frequency measured locally at a plant level.

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, non-synchronous 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.[5] 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.[6]

PFR is required for effective frequency control, in coordination with inertia and secondary frequency control services, for both normal power system operation and following contingency events.[7]

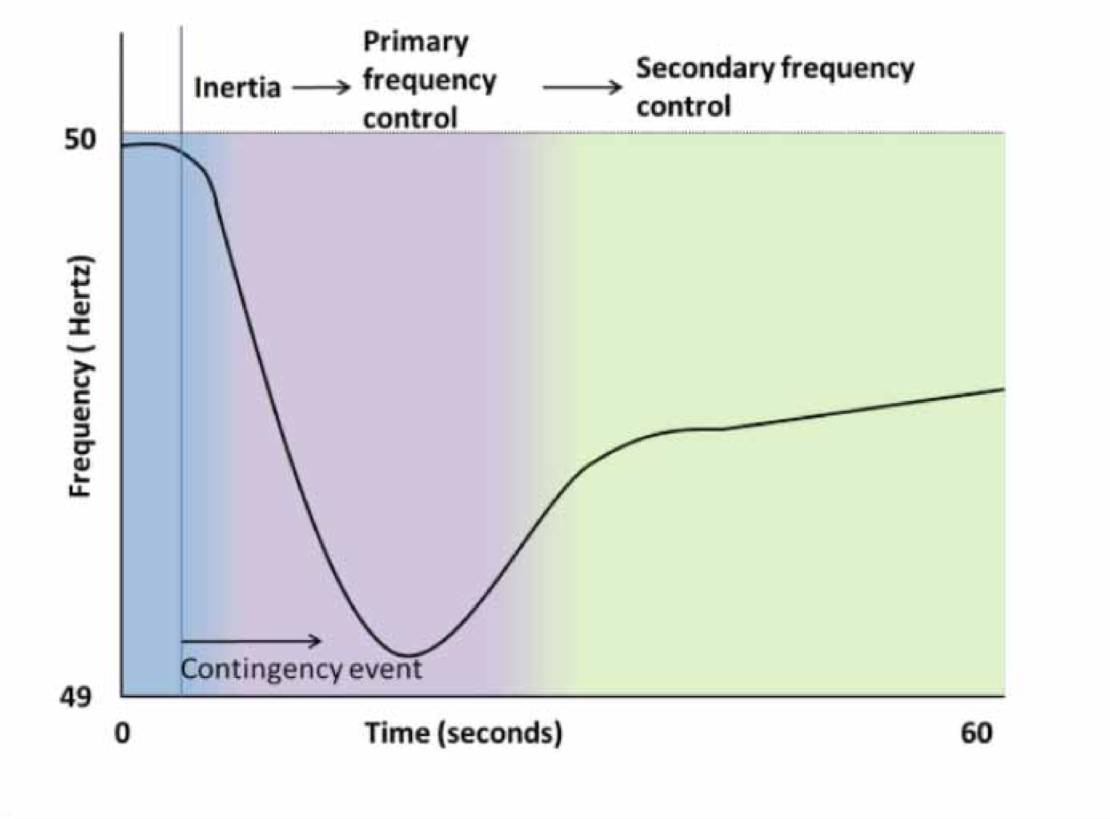
Figure 1.2 below demonstrates how PFR interacts with inertia and secondary frequency control services following a contingency event.

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

6 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).

7 Following a sudden change in the balance between generation and load in the power system, the initial rate of change of system frequency following a contingency event is determined by the system inertia. 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.

**Figure 1.2: Interaction between inertia, and primary and secondary frequency control**




Source: AEMC

### Overview of AEMO's tools for managing frequency

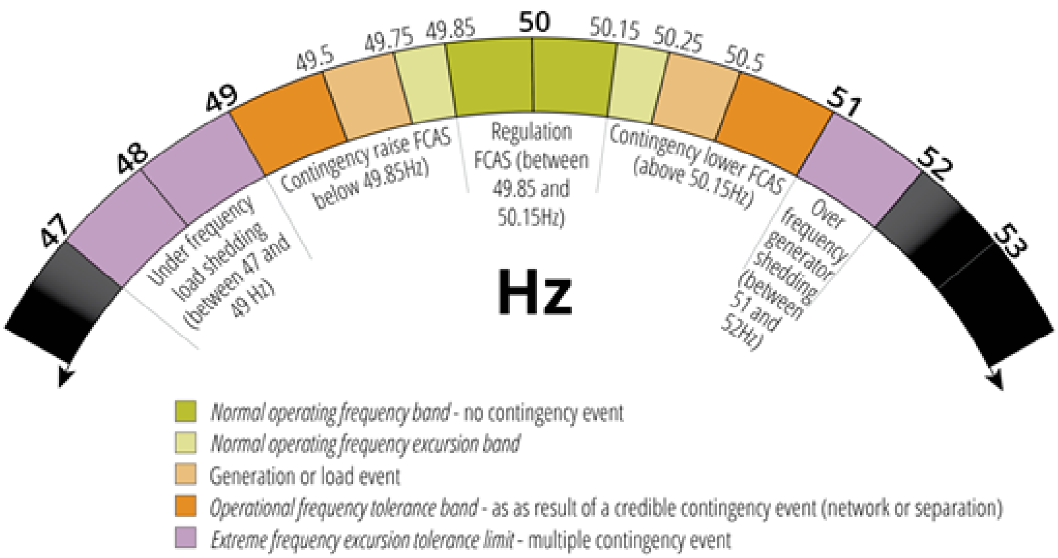
AEMO is responsible under the NER for maintaining power system security. One aspect of this is that AEMO must use its reasonable endeavours to control power system frequency.[8] AEMO controls frequency during normal operation and manages the impact of contingency events through a coordinated use of the following six 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.

8 Clause 4.4.1(a) of the NER.

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 1.3.

**Figure 1.3: Frequency control tools and active frequency bands**




Source: AEMC

## 1.3 Recent developments on primary frequency response

The AEMC's *Frequency control frameworks review* final report, published on 26 July 2018, identified that 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 disincentives associated with operating their plant in a frequency responsive mode.[9] 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, installing secondary control systems to dampen the primary governor response of their generating units, in favour of maintaining alignment of generator output with dispatch targets.

9 AEMC, 26 July 2018, Frequency control frameworks review — Final report, p.69.

Analysis performed for AEMO by DIGsilent in 2017 confirmed that the net result of these changes to generator control systems has been a reduction in the level of PFR that contributes to maintaining the power system frequency within the NOFB and following large contingency events.[10]

Prior to this determination, the NER did 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.

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.

The AEMC's *Frequency control frameworks review*, which concluded in July 2018, provided an important foundation for understanding and assessing the issues. The Commission concluded that frequency performance under normal operating conditions had been deteriorating and that changes to the existing frameworks were required to support effective frequency control in the national electricity system. 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 included a collaborative 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.

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*. The AEMC's final report therefore did not recommend any regulatory change in the immediate term to address the deterioration, but concluded that there is a need to find a more permanent solution to the issue and set out a number of options for further development. However, the power system incident that occurred on 25 August 2018 led to AEMO confirming an urgent need for regulatory changes to arrest the ongoing decline in the frequency performance in the NEM, in particular the resilience of the NEM to similar major disturbances.[11]

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.

10 DIgSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017.

11 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.9.

## 1.4 Rationale for the rule change requests

AEMO considers frequency response following non-credible contingency events to be a critical issue and so submitted the rule change request, which is the subject of this final determination.[12]

As set out in its rule change request, 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.[13]

AEMO's rule change requests are related to this work plan. 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 and security of the power system.

AEMO requested that the AEMC progress its rule change request, *Mandatory primary frequency response*, 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. AEMO recognised that its proposed rule for the mandatory provision of primary frequency response 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 in approach is now urgently required.[14]

AEMO set out in its rule change request the following reasons why it considers a regulatory change to provide for effective frequency control in the NEM is required without delay:[15]

- 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.

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

13 Ibid, pp.26-28.

14 Ibid, pp.41.

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

- The NEM is currently experiencing a rapid rate of connection of new generation, with 7GW of committed projects and 53 GW of proposed projects.[16] AEMO is concerned that 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.[17]
- AEMO expects that the commencement of the Five-Minute Settlement Rule on 1 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 settlement time frame by more rapidly increasing or decreasing their output. As a result, 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.[18]
- AEMO maintains that the physical needs of the power system, in relation to secure operation, are paramount to economic considerations.[19] AEMO considers that 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.[20]

## 1.5 Solutions proposed in the rule change requests

The following sections provide a summary of AEMO and Dr Sokolowski's proposed rules, including:

- proposals for a mandatory PFR requirement
- other proposed changes to the NER.

### 1.5.1 Proposals for mandatory PFR proposal

**AEMO's proposed mandatory 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 procedures.[21]

AEMO's proposed rule sought to require all capable scheduled and semi-scheduled generating units to provide PFR once frequency moves outside a defined frequency band. AEMO

16 AEMO, Generation Information, 8 August 2019

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

18 Ibid, p.43.

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

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

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

suggested that effective control and resilience of the power system would be achieved with a narrow response deadband. AEMO suggested 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.

AEMO considered that a mandatory requirement for generators to provide PFR is needed for the following reasons.

- **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. Greater power system resilience through the broad-based provision of PFR is required to manage these more complex disturbances.[22]
- **Allows for improved power system planning** — A broad-based provision of PFR provides more predictable and consistent generator behaviour. supports effective and accurate power system modelling, and facilitates good planning and design of emergency frequency control schemes, such as UFLS and OFGS.[23]
- **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.[24]
- **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.[25]
- **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.[26]

AEMO's rule change proposal is supported by advice provided by international power system expert, Dr. John Undrill, that an obligation to provide PFR should apply to all generating systems, to the extent that it is practical to do so.[27] This is intended to be a conservative and prudent approach to maintaining system security and resilience within a power system that is undergoing rapid technological transformation.

#### Dr Sokolowski's proposed mandatory PFR requirement

Dr. Peter Sokolowski's rule change request also proposed a mandatory obligation that would be implemented through the generator performance standards in S5.2.5.11 of the NER and be intended to apply to all registered generation in the NEM.

22 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.24.
23 Ibid, p.26.
24 Ibid, p.20.
25 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.20.
26 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.37.
27 Dr. John Undrill, *Notes on frequency control for the Australian Energy Market Operator*, 5 August 2019, p.3.

### 1.5.2 Other proposed changes to the NER

#### Other proposed changes in AEMO's rule change request

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:

- 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.[28]

AEMO's rule change request also 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.[29]

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. Clause S5.2.5.11(i)(4) in the NER sets out that 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.

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.

#### Other proposed changes in Dr. Sokolowski's rule change request

Dr. Peter Sokolowski's rule change request also proposes a number of other changes to the NER that are intended to improve frequency control and system security in the NEM. The proposed rule revises:[30]

- 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.

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

29 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.13.

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

- 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 subject to local power system conditions.
- clause S5.2.5.14 to clarify that a scheduled generating unit or a scheduled generating system should be capable of controlling its active power output "subject to local frequency".
- 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.[31]
- clause 5.20B.5(g) to explicitly refer to fast frequency response as being a potential source of inertia support activities, and revise the Chapter 10 definition of inertia.

## 1.6 The rule making process

On 19 September 2019, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change requests.[32] A consultation paper identifying specific issues for consultation was also published. Submissions closed on 31 October 2019.

The Commission received 31 submissions as part of the first round of consultation. The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions on the consultation paper are discussed and responded to throughout this final rule determination. Issues that are not addressed in the body of this document are set out and addressed in appendix f.

On 19 December 2019, the Commission published a notice to consolidate its assessment of the two rule change requests — ERC0274 *Mandatory primary frequency response* and ERC0277 *Primary frequency response requirement*. At the same time, the Commission published a draft determination and draft rule with respect to these consolidated rule change requests.

Consistent with the request from AEMO, the AEMC has considered these rule changes as a priority, with the draft determination published earlier than the AEMC is required to do under the statutory time frames.

The Commission received 24 submissions in response to the draft determination. Issues raised in submissions on the draft determination are discussed and responded to throughout this final rule determination. Issues that are not addressed in the body of this document are set out and addressed in appendix f.

The Commission also formed a technical working group of experts from industry and consumer groups. Two meetings of the technical working group were held on 18 November 2019 and 26 February 2020.

31 Dr. Peter Sokolowski, Primary frequency response requirement - Electricity rule change proposal, 30 May 2019, p.12.

32 This notice was published under s.95 of the National Electricity Law (NEL).

# 2 FINAL RULE DETERMINATION

## 2.1 The Commission's final rule determination

The Commission's final rule determination is to make a more preferable final rule (hereafter called "final rule").

The final rule is attached to and published with this final rule determination. The more preferable final rule:

- creates an obligation on each scheduled generator and semi-scheduled generator that has received a dispatch instruction to generate at a volume greater than zero MW to operate its generating system in accordance with the PFRR as applicable to that generating system
- clarifies that compliance with the above obligation does not require a scheduled generator or semi-scheduled generator to:
    - maintain additional stored energy for the purposes of providing frequency response in accordance with the requirements of the PFRR
    - install or modify monitoring equipment to monitor and record the response of the relevant generating system to changes in the frequency of the power system for the purpose of verifying compliance with the PFRR
- creates an obligation on AEMO to develop, publish on its website and maintain the PFRR in accordance with the Rules consultation procedures[33]
- sets out that the PFRR must include:
    - a requirement that Scheduled Generators and Semi-Scheduled Generators set their generating systems to operate in frequency response mode within one or more performance parameters (which may be specific to different types of plant) which must include maximum allowable deadbands (which must not be narrower than the *primary frequency control band* — the range of 49.985 Hz to 50.015 Hz or such other range as specified by the Reliability Panel in the FOS) outside of which Scheduled Generators and Semi-Scheduled Generators must provide primary frequency response, and may include but is not limited to droop and response time;
    - the conditions or criteria on which a Scheduled Generator or Semi-Scheduled Generator may request, and AEMO may approve, a variation to, or exemption from, any performance parameters applicable to its generating system;
    - the process and timing for an application for a variation or exemption, and the process for approval by AEMO;
    - details of the information to be provided by Scheduled Generators and Semi-Scheduled Generators to verify compliance with the PFRR and any compliance audits or tests to be conducted;
- creates an obligation on AEMO to publish on its website and maintain a register of Generators who have been granted an exemption or variation from the PFRR

33 The PFRR will need to be revised from the current draft version to reflect this final rule.

- sets out the matters and principles that AEMO must have regard to when approving a variation or exemption including:
  - the capability of the generating system to operate in frequency response mode;
  - the stability of the generating system when operating in frequency response mode, and the potential impact this may have on power system security;
  - any other physical characteristics of the generating system which may affect its ability to operate in frequency response mode, including but not limited to dispatch inflexibilities, operating requirements, or energy constraints;
  - whether the scheduled generator or semi-scheduled generator has been able to establish to AEMO's reasonable satisfaction that the implementation of the primary frequency response parameters applicable to that scheduled generator's or semi-scheduled generator's generating system will be unreasonably onerous having regard to, amongst other things:
    - the likely costs of modifying the generating system to be able to operate in frequency response mode; and
    - the likely operation and maintenance costs of operating the generating system in frequency response mode

    relative to the revenue earned from the provision of energy and market ancillary services by the generating system in relation to its operation in the *NEM* during the 12 months prior to the date of the application for exemption or variation, as applicable.
- clarifies that cost information provided to AEMO as part of an application for variation or exemption is confidential information
- clarifies that a Registered Participant which has classified a scheduled generating unit, scheduled load, ancillary services generating unit or ancillary service load will not be assessed as contributing to the deviation in the frequency of the power system if within a dispatch interval it achieves its dispatch target at a uniform rate subject to the provision of PFR by that Participant in accordance with the PFRR. This removes a potential disincentive for voluntary provision of PFR by a Registered Participant with scheduled or ancillary service load.
- clarifies that a Scheduled Generator or Semi-Scheduled Generator is not taken to have failed to comply with a dispatch instruction as a consequence of it operating its generating unit in frequency response mode to adjust power system frequency in response to power system conditions
- provides that clause 5.3.9 (which sets out the requirements for generators proposing to alter a connected generating system) does not apply in relation to any modifications made to a generating system by a Scheduled Generator or Semi-Scheduled Generator in order to comply with the PFRR
- introduces transitional arrangements that require AEMO to:

- make and publish on its website interim Primary Frequency Response Requirements by 4 June 2020 to apply until the first Primary Frequency Response Requirements are made.
- publish a draft of the *Interim Primary Frequency Response Requirements* on its website by 9 April 2020 and provide at least 20 business days for written submissions on this draft.
- develop and publish the first Primary Frequency Response Requirements under the new rules by 6 December 2021.

The more preferable final rule also includes Schedule 2 which removes the mandatory primary frequency response framework from the rules as at 4 June 2023. This allows time for the appropriateness of the mandatory arrangement to be reviewed and an alternative or complementary incentive arrangement to be developed before the sunset to the mandatory arrangements. The relevant rules will then revert to the version of those rules in existence at the time this rule is made.

An overview of the more preferable final rule can be found in Chapter 4 with more detailed discussion of the various elements found in the accompanying appendices.

The Commission's reasons for making this final determination are set out in section 2.4.

This chapter outlines:

- the rule making test for changes to the NER
- the more preferable rule test
- the assessment framework for considering the rule change request
- the Commission's consideration of the more preferable final rule against the national electricity objective

Further information on the legal requirements for making this final rule determination is set out in Appendix E.

## 2.2 Rule making test

### 2.2.1 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).[34] This is the decision-making framework that the Commission must apply.

The NEO is:[35]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and

34 Section 88 of the NEL.

35 Section 7 of the NEL.

(b) the reliability, safety and security of the national electricity system.

### 2.2.2 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 than the proposed rule.

In this instance, the Commission has made a more preferable final rule. The reasons are summarised below. More detailed reasons for making this more preferable final rule, including detailed analysis of the issues raised and responses to them, are set out in Appendix A, Appendix B, Appendix C and Appendix D.

### 2.2.3 Rule making in relation to the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the NEL.[36] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.[37]

As the final rule either relates to parts of the NER that currently do not apply in the Northern Territory or have no practical application in the Northern Territory, the Commission has not assessed the rule against the additional elements required by the Northern Territory legislation.[38]

## 2.3 Assessment framework

The Commission has sought to 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.

AEMO requested that its rule change request for mandatory primary frequency response be assessed in the shortest reasonable time frame, balancing the requirement for appropriate

36 The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

37 The version of the NER that applies in the Northern Territory is available on the AEMC website.

38 From 1 July 2016, the NER, as amended from time to time, apply in the NT, subject to derogations set out in regulations made under the NT legislation adopting the NEL. 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.) National Electricity(Northern Territory) (National Uniform Legislation) Act2015.

consultation with the potential consequences of the ongoing lack of effective frequency control during normal operating conditions. In determining the immediate solution, the Commission is seeking to address system security first and foremost. Whilst the Commission acknowledges the need to create incentives for parties to provide primary frequency response, it also considers that developing such arrangements should not come at the expense of a secure and stable power system. The Commission considers that the implementation of a mandatory primary frequency response requirement will meet the immediate fundamental system security needs identified by AEMO and its expert consultant, Dr John Undrill, in its rule change request. Following this, the Commission will seek to investigate further improvements to the frequency control arrangements that would incentivise and reward participants for providing primary frequency response through the assessment of the *Removal of disincentives to primary frequency response* rule change as well as any other relevant rule change requests received.

This approach is consistent with the frequency control work plan that was set out in 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. The Commission has prepared an update to this work plan in collaboration with the ESB and other market bodies which sets out a pathway to the development of future arrangements to create incentives for the provision of primary frequency response. This work plan is explored further in chapter 3.

In assessing the consolidated rule change request, the Commission has considered whether the proposed rules are likely to support and improve the security of the power system along with their impacts on the effectiveness and efficiency of frequency control frameworks.

In addition, in assessing the rule change request against the NEO the Commission has considered 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 has had 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.

## 2.4 Summary of reasons

In assessing whether the proposed rule is likely to meet the NEO, the Commission has balanced 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 ultimately likely to be borne by consumers.

The Commission accepts the views expressed by AEMO in its rule change request and supported by its expert advice that a mandatory requirement for primary frequency response applied to a broad cross-section of the generating fleet would mean that costs incurred by each *individual* generator would likely be minimised. If every scheduled and semi-scheduled generator provides primary frequency response then this will minimise the costs for each individual generator, since no one generator will bear the burden of responding — instead, this will be shared across the entire fleet.

Given that the wholesale market is competitive, this means that the generators will all be able to recover their costs through adjusting their energy market offers, and so in turn, wholesale energy market prices. Wholesale electricity prices will reflect the necessary cost of providing primary frequency response in order to manage system security. Obviously, it will be harder for generators with higher costs than the marginal generator, and those that are lower in the merit order to recover their costs through the energy market. However, the Commission considers that this is likely to be manageable.

Having regard to the issues raised in the consolidated rule change request and during consultation, the Commission is satisfied that the more preferable final rule will, or is likely to, better contribute to the achievement of the NEO than the proposed rule for the following reasons.

- An increase in the provision of primary frequency response from generators will improve the security of the national electricity system for the benefit of consumers and will give AEMO more confidence that it is maintaining the power system in a secure operating state. Any frequency response that is provided in addition to 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. Improved frequency control will decrease the risk of generation shedding and decrease the risk of unserved energy associated with load shedding following large contingency events.
- Improvements in the efficiency of wholesale market operation due to AEMO being able to more accurately measure and predict the system operating state. Improved frequency control during normal operation means that the frequency will be maintained more closely to 50 Hz 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 by AEMO, thereby reducing wholesale energy prices for the benefit of consumers.
- Improved frequency performance, particularly during normal operation translates into a more stable system frequency that is maintained more closely to 50 Hz. 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, which means that 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. Smoother operation of synchronous generating plant and a reduction in maintenance and shut-down costs will improve reliability outcomes and lower wholesale energy prices in the interests of consumers.

The Commission considers that the final rule is more preferable than the proposed rule for the following reasons.

- The final rule introduces a new *primary frequency control band* of 49.985 Hz to 50.015 Hz, which sets a lower bound on the deadband to which individual generators must comply under the conditions of the PFRR. The Commission considers that the *primary frequency control band* is a key variable associated with the final rule, which has implications for both system operation and the operation of the markets for electricity and ancillary services in the NEM. In the absence of a clearly defined frequency performance standard in the frequency operating standards, the Commission has determined that the lower bound for the *primary frequency control band* be specified in the NER, and not subject to full discretion by AEMO in the PFRR. This will provide for a comprehensive assessment of any potential changes to the *primary frequency control band*, as it applies to generators, relative to the potential benefits that it provides to the security of the power system.
- The Commission has specified in the final rule that the PFRR cannot require generators to maintain additional headroom or stored energy for the purpose of providing primary frequency response.[39] The Commission acknowledges that AEMO did not propose to include a requirement in the PFRR that generators maintain headroom as part of its proposed rule. However, the PFRR is subject to change, and any future obligation which results in a large cross-section of the generating fleet maintaining headroom would likely impose substantial costs on generators that outweigh the additional benefits this might provide to the security of the power system. This aspect of the final rule will provide greater clarity and certainty to generators and will limit the likelihood of substantial unwarranted costs being incurred by generators in the future, thereby limiting impacts on wholesale prices for the benefit of consumers.
- The final rule requires that the PFRR includes provision for generators to request, and AEMO approve, an exemption or variation from the requirements specified by AEMO in the PFRR applicable to their generating system. The final rule sets out a series of principles to guide AEMO in considering any such requests. The Commission expects that the costs for each generator to meet the performance parameters for PFR will vary, with some plant requiring significant plant upgrades and control system tuning in order to provide PFR in accordance with the performance parameters. The exemption framework introduces a degree of flexibility that avoids excessive compliance costs for eligible generation plant while still delivering on AEMO's system security and frequency control objectives.
- While a mandatory approach may be necessary in the interim in order to meet immediate system security needs, it would be preferable for this approach to be complemented in the longer-term by incentives and rewards for providing frequency response. Given the time associated with developing such arrangements it is not possible to do this in time to

39 Available headroom for frequency response refers to the capacity for a generator to raise its generation output in response to a drop in system frequency. It is dependent on the generating level of the plant based on market dispatch along with energy source availability and plant operating limits. Unless curtailed due to system constraints, semi-scheduled generators such as solar and wind power stations typically do not maintain stored energy or headroom, as their generation output is limited by the energy availability of the wind or sun. On the other hand, scheduled generators including thermal, hydro and batteries typically operate with some level of stored energy availability which varies by plant type. Scheduled generators maintain stored energy for a range of reasons, including maintaining a minimum ramp rate capability and in accordance with being enabled in the market for provision of frequency control ancillary services.

address the immediate system security needs. Therefore, the final rule includes provision for a sunset after a period of three years. This creates a clear signal that the Commission is committed to the development of an arrangement that appropriately incentivises primary frequency response provision to be put in place prior to the sunset. The Commission intend to deliver on this through the assessment of the *Removal of disincentives to primary frequency response* rule change as well as any other relevant rule change requests received.

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 or complementary market or incentive-based arrangement, the Commission recognises that there is an immediate need for improved frequency control in the NEM. The Commission considers that it is not appropriate to continue to operate the NEM without effective frequency control during normal operation, and that a regulatory change is needed now in order to restore effective frequency control and resolve immediate system security concerns. The Commission is satisfied that the final rule to mandate the provision of PFR, together with the proposed exemption framework will meet the immediate need for effective frequency control while limiting the costs associated with the implementation of such an approach to those costs that are necessary to meet the immediate system security need.

The Commission considers that the economic optimisation of the provision of PFR is an important consideration in minimising the long-term costs to consumers. A 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 development and implementation of a framework to more effectively optimise the economic provision of frequency control will be undertaken when the immediate system needs are satisfied. The inclusion of a sunset arrangement for the mandatory primary frequency response requirement means that this will need to be implemented prior to June 2023. Chapter 3 sets out further detail on the Commission's long-term reform pathway.

# 3 ONGOING FREQUENCY CONTROL WORK PLAN

The key deliverable arising from the AEMC's *Frequency control frameworks review* in July 2018 was a work plan developed collaboratively by the AEMC, AEMO and the AER, in consultation with stakeholders, which set out a series of actions to address a range of frequency control issues over the next few years.

A key action in the *Frequency control work plan* itself was the development of a longer-term mechanism for the procurement of a primary regulating response and other frequency services as the needs of the power system evolve. The work plan also set out a range of short-term actions for AEMO to undertake in an attempt to better understand the drivers of the deterioration, and to appropriately address it. At the time, AEMO advised that there was no immediate need to implement regulatory change to address the deterioration in frequency performance before the results of its short-term actions to understand the issue are known, and that current regulatory tools were expected to be adequate to manage frequency performance in a manner consistent with the requirements of the frequency operating standard within this time frame.

However, based on the power system events on 25 August 2018, AEMO now considers that there is an urgent need to improve the control of power system frequency in the NEM.

The Commission  has made a final rule in response to AEMO's rule change request, *Mandatory primary frequency response,* and Dr. Peter Sokolowski's rule change request, *Primary Frequency Response Requirements*. The final rule addresses the immediate need, as identified by AEMO, to reinstate narrow band frequency response from the generation fleet to improve the resilience of the power system.

The AEMC remains committed to the implementation of further reforms to appropriately value and reward the provision of frequency control services and, in collaboration with the ESB and other market bodies, has revised the *Frequency control work plan*.

This chapter outlines:

- The AEMC's considerations for progressing a reform pathway for frequency control and the development of incentive-based arrangements for PFR
- Stakeholders' views on the development of frequency control mechanisms
- The  revised *Frequency control work plan*

## 3.1 The final rule is part of the frequency control work plan

The final rule is part of the *Frequency control work plan* that was initiated through the *Frequency control frameworks review*. The work plan included an action that AEMO:[40]

> communicates whether there is a need to implement interim measures before a

40 AEMC, 26 July 2018, Frequency control frameworks review — Final report, p.62.

longer-term mechanism for primary frequency control within the normal operating frequency band comes into effect.

As set out in the consultation paper and draft determination, the Commission intends to continue to progress its frequency control reform agenda as outlined in the *Frequency control work plan*. In particular, when the fundamental and immediate system security needs are met, the Commission will seek to investigate, and consult on, further improvements to the frequency control arrangements to increase the overall economic efficiency of frequency control in the NEM.

To reflect the commitment to the ongoing reform of the frequency control frameworks, the AEMC, in collaboration with the ESB and other market bodies, have developed a revised *Frequency control work plan.* The revised work plan is based on the plan published at the end of the *Frequency control frameworks review* and provides an update on progress to date on key actions along with an indication of the next steps in the reform pathway for frequency control frameworks in the NEM.

The Commission notes that the final rule is separate to the ongoing work plan and is not dependent on any outcomes in the work plan.

The following sections set out:

- how the immediate system security need will be addressed in the short-term and the inclusion of a three-year sunset in the final rule.
- the Commission's next steps for the development of a mechanism to provide a payment to providers of PFR during normal operating conditions.

### 3.1.1 Addressing the short-term system security need and the inclusion of a sunset period

The Commission acknowledges that a rule that introduces a mandatory requirement for generators to activate an existing capability to provide PFR is likely to address the immediate need for improved frequency control in the NEM. However, the Commission recognises that a mandatory requirement for PFR is not a complete solution and it would be preferable to also introduce arrangements that incentivise and reward the provision of frequency control in the NEM. In developing such an arrangement, the Commission recognises the need to properly consider other alternative and complementary measures, including the potential for new market and incentive-based mechanisms for frequency control. Further work also need to be done to understand the power system requirements for maintaining good frequency control. Many stakeholders share this perspective, as discussed in section 3.3.

In the context of the full range of solutions identified through the *Frequency control frameworks review* to improve frequency control during normal operation, the Commission considers that the mandatory PFR requirement is a transitional arrangement that is only acceptable in isolation for an interim period. The Commission is mindful of the costs that such a mechanism, on its own would impose on generators. While these may be necessary in the interim in order to meet immediate system security needs, it would be preferable for these to be complemented by incentives and rewards for providing frequency response. Given the time associated with developing such arrangements it is not possible to do this in time to address the immediate system security needs.

Therefore, the final rule includes provision for a sunset after a period of three years. This creates a clear signal that the Commission is committed to investigate and develop alternative and complementary arrangements that appropriately reward primary frequency response provision to be put in place prior to the sunset. The Commission intend to deliver on this through the assessment of the *Removal of disincentives to primary frequency response* rule change as well as any other relevant rule change requests received.

Once arrangements are in place to address the immediate system security concerns, the ESB, AEMO, the AER and the AEMC will be better placed, in terms of time frames and flexibility, to further develop new approaches to frequency control and PFR. The Commission considers that three years would afford the ESB and all market bodies adequate time to work collaboratively in determining such a mechanism for procuring PFR in the NEM.

### 3.1.2 Next steps for the development of appropriate incentive arrangements for PFR

The next major step for progressing the *Frequency control work plan* is for the Commission to progress its assessment of the *Removal of disincentives to primary frequency response* rule change.

Through the *Removal of disincentives* rule change the Commission will investigate the appropriateness of the existing incentives for PFR during normal operation and amend these arrangements as required to meet the future needs of the power system.

In Q2 2020, the Commission will work with stakeholders and AEMO on the detailed directions for this rule change which will consider:

- the arrangements for allocation of costs associated with regulation services — 'causer-pays'
- the potential development of additional complementary measures to effectively remunerate providers of primary frequency response
- how best to meet the future needs of the power system
- interaction with the arrangements in the *Mandatory primary frequency response* final rule including the sunset arrangements.

The indicative timing for the *Removal of disincentives to the provision of primary frequency control rule change process is:*

- Directions paper - Q2 2020
- Draft determination — September 2020
- Final determination — December 2020

The Directions paper will provide further detail on the possible outcomes and timing for the rule change process.

The Commission will continue to consult with stakeholders throughout the rule change process including through the continuation of the technical working group for the PFR rule changes.

## 3.2 AEMO's views on long-term reform

As AEMO stated in its submission to the *PFR rule changes* consultation paper, AEMO supports the development of an incentive-based mechanism for PFR over the long-term, provided a mandatory requirement for PFR is implemented first:[41]

> Once the mandatory PFR rule is made and implemented, AEMO would work with the AEMC and industry on options for incentivising a market mechanism for PFR.

While AEMO is committed to investigating different mechanisms for procuring frequency control services through the *Frequency control work plan*, as explicitly stated in AEMO's *Mandatory primary frequency control* rule change request[42], AEMO does not believe an incentive-based mechanism on its own would be sufficient to meet the system security needs of the system. AEMO envisaged that any proposed incentive arrangement for PFR would have to exist in parallel with the mandatory PFR requirement:[43]

> AEMO supports the development of new mechanisms to incentivise better performance than what is required by the PFRR only if they operate in parallel to a near-universal PFR obligation. AEMO does not believe an incentive mechanism alone could achieve all objectives of its rule change requests without ensuring a broad level of participation.

AEMO considered that there is little international experience in relying on incentive mechanisms alone for the provision of PFR.[44]

AEMO noted that the existing Contingency and Regulation FCAS markets will continue to provide commercial arrangements for the procurement of frequency control services and AEMO is undertaking work to remove disincentives for generators to offer reserves into these markets. In line with this, AEMO is undertaking a range of actions relevant to the *Frequency control work plan* which will progress work by AEMO and the AEMC towards improved mechanisms for procuring PFR, including:

- work to better understand the frequency control needs of the future power system, such as AEMO's *Renewable Integration Study*,

41 AEMO, submission to the *PFR rule changes* consultation paper, 31 October 2019, p. 1

42 AEMO, *Mandatory primary frequency control* rule change request, August 2019, pp. 7-9

43 ibid., p. 10

44 ibid.

- review and make improvements to current frequency control mechanisms, including contingency FCAS quantities, AGC systems and an ongoing review of the MASS.[45]

In its submission to the AEMC's draft determination on the *Mandatory primary frequency response* rule change request, AEMO stated that:

> While it is not entirely clear from the Draft Determination, AEMO understands that the AEMC is proposing to work with AEMO and industry to develop a potential interim incentive scheme for the provision of PFR and will then focus on a more holistic review of frequency control. AEMO endorses the complementary nature of an incentive scheme that could act alongside a near-universal provision of PFR.
>
> AEMO welcomes the opportunity to work with the AEMC and industry on this very important aspect of improving power system security and resilience.

Therefore, the Commission intends to start investigating alternative and complementary arrangements to provide adequate primary frequency response through the assessment of the *Removal of disincentives to primary frequency response* rule change and any other related rule change requests recieved.

## 3.3 Stakeholder views on the consultation paper

The following sections summarise stakeholder submissions to the consultation paper in relation to the appropriateness of a mandatory PFR requirement and the development of incentive and market-based arrangements to value PFR.

It also includes an overview of some alternative pathways to progress reform of the frequency control frameworks proposed by Delta Electricity and CS Energy in their submissions.

### 3.3.1 General advocacy for a more efficient mechanism for PFR

In response to the consultation paper, many stakeholders expressed concern that the proposed mandatory PFR requirement is unlikely to be the most efficient option for valuing primary frequency response in the long-term. These stakeholders reasoned that incentive or market-based arrangements to provide PFR would likely be more efficient and effective over the longer term.[46] Stakeholders highlighted a number of key concerns with the existing frameworks which they believe could be efficiently addressed through an incentive-based mechanism for PFR, including:

45 On 25 February 2020, AEMO published a draft determination on the MASS. See AEMO's consultation page at: https://aemo.com.au/consultations/current-and-closed-consultations/primary-frequency-response-under-normal-operating-conditions

46 Submissions to the consultation paper: CS Energy, p. 2, Delta Electricity, p. 6, Neoen p. 1, Enel X, p. 8, IES, p.2, Enel Green Power, p. 2, ARENA, p.3.

- PFR should be valued to reflect the costs to generators of providing the service
- Generators should be incentivised to maintain headroom if a PFR mechanism is to be technically effective
- PFR should be procured at economically efficient levels
- Appropriate economic signals should exist for investment and innovation

Many stakeholders have also expressed preference for particular types of incentive mechanisms to be developed.

**Proposed voluntary PFR trial**

Prior to the publication of the draft determination the AEC proposed an industry lead voluntary provision of narrow band primary frequency response to address the immediate power system need for effective frequency control. [47]

AEMO responded to the AEC's proposal in its submission to the consultation paper:[48]

> The voluntary provision of PFR might also be helpful in identifying the actual impact on individual generating units/systems of changes to their control systems, however, volunteered generating plant is likely to experience an increase in the operating impact above what would be expected with broader system-wide PFR provision, due to the greater individual burden placed on the limited, volunteered plant.
>
> AEMO emphasises that a voluntary trial of increased provision of PFR from a limited group of generating systems cannot be a durable substitute for the broad requirement proposed in the rule change requests. Among other reasons, it would be dependent on voluntary participation which, in theory, could be withdrawn at any time. Such an arrangement would only serve as a stop-gap mechanism at best, and would not fully or reliably achieve the objectives of the rule change requests.

The AER also commented on AEC's proposal for a voluntary trial in its submission to the consultation paper, expressing support for its realisation.[49]

> We also note the Australian Energy Council (AEC) has put forward an interim solution for some generators to voluntarily provide PFR for a trial period. This appears to be a practical and pragmatic solution that can be quickly implemented to address the urgency of this issue. This interim solution will allow time for further study of the issue, including how much PFR is required to restore frequency performance to acceptable

47 AEC, Submission to the consultation paper, 31 October 2019, p.5.
48 AEMO, Submission to the consultation paper, 31 October 2019, p.9.
49 AER, Submission to the consultation paper, p. 2.

> levels—which is not currently well understood. Such a trial approach was recommended by the AEMC in its 2018 review.

The Commission understands that AEMO were supportive of industry led efforts to improve system performance and appreciated the efforts made by the AEC and its members in trying to bring together sufficient plant to offer a voluntary mainland trial of PFR. However, AEMO did not see the offer for a voluntary trial as a suitable substitute for the immediate implementation of the PFR requirement. AEMO considered that the proposed voluntary scheme would be a departure from the primary objective of the Mandatory PFR rule change proposal to maximise participation from scheduled and semi-scheduled plant to increase the resilience of the power system. This objective is documented in the rule change request and the accompanying advice from Dr. John Undrill, as well as power system operating practice in other international jurisdictions.

The Commission accepts AEMO's advice that there is an immediate need for the reinstatement of arrangements in the NER that provide for effective frequency control and which support the secure and resilient operation of the national electricity system. As AEMO did not advise that this immediate need has been met through other means, the Commission has made a final rule that introduces a mandatory requirement into the NER for generators to provide primary frequency response in accordance with the performance specifications set out in the *Primary frequency response requirements*.

**The costs of providing PFR**

Many stakeholders consider that the costs of providing PFR are not insubstantial and vary for individual generators. Stakeholders argue that mandating PFR provision without valuing PFR based on the different costs incurred by generators to provide PFR distorts competition in the energy markets and so PFR should be appropriately valued.

CS Energy, Stanwell and Delta Electricity identify that thermal generators experience costs related to thermal inefficiencies, where fuel usage increases to maintain stored energy for PFR provision.[50] Delta Electricity quantifies the cost of maintaining 10% headroom for a coal unit:[51]

> The 10% stored energy is known to equate to about 0.9% additional coal consumption. Based on nominal conditions and present coal tonnage costs, this equates to about $1M p.a. per 660MW unit.

Tilt Renewables expects that the ongoing costs incurred by semi-scheduled generators will be greater than those incurred by scheduled generators as semi-scheduled generators typically

50 Submissions to the consultation paper: CS Energy, p. 9, Delta Electricity, p. 32, Stanwell p. 6.

51 Delta Electricity, Submission to the *PFR rule changes* consultation paper, 31 October 2019, pp. 32-33.

operate at full output with no headroom and so will mostly provide lower PFR, resulting in lost energy revenue. Tilt Renewables estimates the loss of energy generation due to the mandatory PFR requirement will:[52]

> ...likely to be in excess of 1% of NEM generation revenues, assuming the current frequency performance in the NEM.

A number of stakeholders have expressed that requiring narrow band PFR provision will likely see large costs for batteries due to increased cycling causing substantial wear and tear. [53] Infigen in particular notes that a battery's warranty typically allows for it to cycle once a day, yet being required to provide PFR continuously can absorb 17.4% to 55% of a 10MW/10MWh battery's warranty limit on energy throughput due to PFR alone.[54]

In general, many stakeholders acknowledge that generators experience different wear and tear costs and opportunity costs dependent on operational and contractual particulars.[55]

A number of stakeholders, including CS Energy, Delta Electricity and Stanwell, consider that, in lieu of a payment for PFR provision, generators would recover the costs of PFR through the energy markets, increasing the energy costs paid for by consumers.[56] Providers of PFR would experience greater costs of energy provision than generators that are not frequency responsive, placing PFR providers in a worse competitive position and creating perverse incentives to avoid providing PFR.[57]

#### Economically efficient levels of PFR

Many stakeholders do not believe that all generators need to provide PFR for effective frequency control and to obligate all to do so would result in an oversupply of PFR, the inefficient costs of which would be borne by consumers. Some stakeholders have suggested that the required volume of PFR may be much less than a near universal provision:

- Tesla points to the UK's *Enhanced Frequency Response* service to which the National Grid (UK ISO) attributed significant economic benefits from the procurement of 200MW of frequency response services. [58]
- ARENA considered the required volume of PFR to meet system needs is likely to be similar to current regulation FCAS volumes.[59]
- Stanwell argues that AEMO observed a clear improvement in system frequency performance following the PFR trials in Tasmania where approximately 30% of generators

52 Tilt Renewables, Submission to the *PFR rule changes* consultation paper, 31 October 2019, p. 2.
53 Submissions to the consultation paper: Infigen, p. 2, Enel X, pp. 3-6, Stanwell p. 4.
54 Infigen, Submission to the *PFR rule changes* consultation paper, 1 November 2019, pp. 3-5.
55 Submissions to the consultation paper: Neoen, p. 4, Tilt Renewables, p. 3, CS Energy, p. 2-4.
56 Submissions to the consultation paper: Delta, p. 23, Stanwell, p. 4, CS Energy, p. 2-4.
57 Snowy Hydro, Submission to the *PFR rule changes* consultation paper, 31 October 2019, p. 4.
58 Tesla, Submission to the *PFR rule changes* consultation paper, 31 October 2019, p. 4.
59 Tesla, Submission to the *PFR rule changes* consultation paper, 1 November 2019, p. 2.

had reduced or removed deadbands. Stanwell recognised the Tasmanian power system is different to the mainland power system but believes the trials provide evidence that universal PFR is not required.[60]

In their responses to the consultation paper, ERM Power, Delta Electricity and Energy Australia suggested that an effective mechanism for frequency control should be assessed by its ability to meet the FOS, as defined by the Reliability Panel. Designing a mechanism to meet requirements beyond the FOS raises questions as to whether the level of PFR being procured is necessary and cost-efficient.[61]

#### Appropriate economic signals for investment and to value innovation

A majority of stakeholders commented on the need for economic signals to encourage investment and innovation in frequency control provision, including investment in batteries, FFR provision and demand-side response from DER and VPPs. The mandatory requirement for PFR does not properly value faster frequency control or other frequency services and distorts the FCAS markets, potentially leading to a higher cost for consumers over the long-term. [62]

Stakeholders such as Delta Electricity, Infigen and AGL agreed with the point made in the AEMC's consultation paper that the mandatory PFR requirement will lead to increased supply into the contingency FCAS markets, putting downwards pressure on contingency FCAS prices.[63] ARENA, Powershop, AGL and HydroTasmania also expect that the mandatory requirement will reduce the need for regulation frequency control and therefore undermine the price signals in the regulation FCAS markets as well.[64] However, AEMO considered the impact of additional PFR provision on the regulation FCAS markets would be minimal.[65] ARENA noted that decreased FCAS prices would result in reduced costs to consumers in the short-term.[66]

Most stakeholders were concerned that the lack of economic signals for frequency control services will increase the costs of frequency control over time. The two main reasons for this sentiment are:

- There may be an under supply of PFR and other frequency control services without sufficient investment by new entrants, especially as thermal generators retire.[67]
- The proposed arrangements will not incentivise innovation and investment in more cost-effective frequency control technologies.[68]

60 Stanwell, Submission to the *PFR rule changes* consultation paper, 31 October 2019, pp. 4-5.

61 Submissions to the consultation paper: ERM Power, p. 2, Delta Electricity, p. 6, Energy Australia, p. 2.

62 Submissions to the consultation paper: Tesla, pp. 6-9, Tilt Renewables, p. 1, Energy Australia, p. 6, Origin, p. 2, IES, p. 2.

63 Submissions to the consultation paper: Delta Electricity, p. 2, Infigen p. 2, AGL, p.4

64 Submissions to the consultation paper: Hydro Tasmania, p. 2, ARENA, p. 2, AGL, p.4, Powershop, p.2.

65 AEMO, Removal of disincentives to the provision of primary frequency response Electricity rule change proposal, 1 July 2019, p. 43.

66 ARENA, Submission to the *PFR rule changes* consultation paper, 1 November 2019, p. 2.

67 Submissions to the consultation paper: ERM Power, p. 8, Alinta, pp. 2-3, Stanwell, p. 4, Neoen, p. 5, Enel X, pp. 6-7.

68 Submissions to the consultation paper: Energy Australia, p. 6, Origin, p. 2, Neoen, pp. 1-4.

To expand on the latter point, stakeholders like Energy Australia and Tesla considered that frequency control though demand-side response, such as from DER or through VPPs, should be valued and incentivised through a market or incentive-based mechanism.[69] Enel Green Power supported the importance of new technologies being involved in frequency control in the NEM: [70]

> In the context of an anticipated progressive phase out of conventional thermal generation, EGP considers it important that the proposed rule change does not crowd out the potential of new technologies to provide innovative and cost-effective solutions for managing frequency on the network.

In particular, a number of stakeholders highlighted that preserving investment signals and value streams for battery technologies is especially important for the long-term efficiency of the NEM. Among others, Enel X, Origin and Neoen considered that batteries will become increasingly important in the future power grid for the provision of a suite of system services including firming capacity.[71] Fluence also made the point that batteries are high performing providers of PFR that provide the service at a lower cost than traditional generators, so increased investment in batteries would decrease the costs to consumers of frequency control.[72] To mirror this, the AEC highlighted that sufficient investment in batteries may remove the need for less flexible generation to provide PFR over time.[73]

However, stakeholders considered that an appropriate mechanism for valuing frequency control services would need to be developed to support investment in batteries and emphasises that the impact of the mandatory PFR requirement on FCAS markets damages the current value streams for the technology.[74]

> Neoen is strongly concerned about the negative impact of implementing mandatory PFR requirements on the development of new technologies, particularly batteries, which could be able to offer PFR service with the highest quality standards (speed and accuracy).

> [Meridian Energy] also expect that the regulation Frequency Control Ancillary Services

69 Submissions to the consultation paper: Energy Australia, p. 6, Tesla, pp. 6-9.

70 Enel Green Power, Submission to the *PFR rule changes* consultation paper, 4 November 2019, p. 2.

71 Submissions to the consultation paper: Enel X, p. 1, Origin, p. 2, Neoen, p. 4

72 Fluence, Submission to the *PFR rule changes* consultation paper, 31 October 2019, pp. 1-4

73 AEC, Submission to the *PFR rule changes* consultation paper, 31 October 2019, p. 8

74 Submissions to the consultation paper: Meridian Energy, p. 4, Neoen, p. 1

(FCAS) markets, particularly the raise FCAS market, will be significantly impacted by the introduction of the proposed rule change and that this will have a material impact on the commerciality of both existing and proposed generators, particularly BESS.

### Headroom must be valued for a mechanism to be effective

Without mandatory headroom, or an incentive for generators to preserve headroom, stakeholders suggested that the mandatory requirement for PFR may not result in effective frequency control.

Energy Australia, for one, did not believe AEMO will be able to rely on the provision of PFR under the *Mandatory primary frequency response* rule as AEMO cannot be certain of the amount of headroom generators are voluntarily providing. [75] Furthermore, due to the costs of preserving additional headroom for frequency control, as discussed above, many stakeholders considered that the mandatory requirement for PFR will incentivise generators not to retain headroom or decommit, unless enabled for FCAS.[76] Stanwell was supportive of this view and considered that, under the proposed mandatory requirement, PFR will only be provided by generators enabled for contingency FCAS or which preserve headroom for fast ramping capabilities.[77]

Some stakeholders considered that the loss of voluntary headroom under the mandatory PFR requirement will result in less PFR being provided than if the rule were not made. Some stakeholders were also concerned that a narrow band PFR requirement will result in the headroom that is preserved by generators being utilised for control within the NOFB and therefore not being available for contingency response.[78] Enel Green Power also made the point that VRE's do not typically have headroom to provide raise PFR, yet the penetration of VRE's is continuing to increase.[79]

Stakeholders considered that an effective frequency control mechanism would incentivise the preservation of headroom for PFR, as summarised by the AEC: [80]

> Confidence in frequency response can only come about if the PFR is supported by a known quantity of stored energy. In turn, this can only come about through dispatched, compensated provision, ideally co-optimised with the energy markets similarly to the existing FCAS markets.

75 Energy Australia, Submission to the *PFR rule changes* consultation paper, 31 October 2019, pp. 7.

76 Submissions to the consultation paper: ERM Power, p. 8, Delta Electricity, p. 5, AEC, p. 6, Infigen, p. 7

77 Stanwell, Submission to the *PFR rule changes* consultation paper, 31 October 2019, p. 5

78 Submissions to the consultation paper: Powershop, p. 4, AEC, p. 6, Infigen, p. 7

79 Enel Green Power, Submission to the *PFR rule changes* consultation paper, 4 November 2019, pp. 1-2

80 AEC, Submission to the *PFR rule changes* consultation paper, 31 October 2019, p. 7

### 3.3.2 Proposed pathways – Delta Electricity and CS Energy

Delta Electricity and CS Energy, in their submissions to the consultation paper, each proposed alternative pathways to the development and implementation of a payment mechanism for PFR, including proposed intermediate steps.[81]

#### Delta Electricity

Delta Electricity proposed a set of actions for the development of a market-based mechanism for PFR consisting of five steps:[82]

1. Establish a voluntary trial of tightened deadbands by willing AEC members to be facilitated by the AEMC, AER and AEMO by mid-December 2019.
2. Rule changes and review are completed by the AEMC and the Reliability Panel to redefine the expected quality of frequency control for the NEM.
3. Develop and consult on revisions to the MASS and relevant AEMO operating procedures to include provision of PFR through the existing regulating services.
4. Settlements through FCAS contribution factors remain as currently designed.
5. Modification to monitoring and reporting frameworks to be revised as needed and AEMO should issue market notices accordingly.

#### CS Energy

CS Energy sets out three possible pathways towards the implementation of a deviation pricing mechanism, supported by a wide deadband (±0.5Hz) mandatory requirement as safety net for major frequency disturbances. CS Energy's pathways consider three stages of policy development: [83]

- **Immediate term -** The introduction of a mandatory requirement for PFR, preferably with a wide deadband, to address the immediate concern of system resilience to major frequency disturbances.
- **Short-term -** The implementation of a new or modified framework to incentivise the provision of PFR within the NOFB in the interim before a deviation pricing mechanism can be developed. CS Energy's three pathways each consider alternative short-term mechanisms based on the introduction of a new two-sided causer pays mechanism for PFR or a modification of the current Contingency FCAS market.
- **Long-term -** Any tight-band mandatory requirement is widened to (nominally) ±0.5Hz and a "pay-and-paid-on performance marginal price incentive" mechanism, like deviation pricing, is introduced as the enduring solution for procuring frequency control services.

To determine how the costs or payments for PFR may be calculated, CS Energy also presents work done in conjunction with IES to determine an "Efficient Cost" estimate for lower and raise PFR for any particular generator. These costs are determined from a calculated system need for PFR (ACE-Reg) and the addition of the opportunity costs of a generator preserving

81 Submissions to the consultation paper: Delta Electricity, pp, 32-36, CS Energy, pp. 20-26

82 Delta Electricity, Submission to the *PFR rule changes* consultation paper, 31 October 2019, pp. 34-36

83 CS Energy, Submission to the *PFR rule changes* consultation paper, 31 October 2019, pp. 20-26

headroom and the costs of utilising this headroom. CS Energy provides analysis to support that the estimation of "Efficient Costs" for each generator can be calculated 'live' using four second data as the spot price and quantity of raise and lower PFR required by the system vary over time.[84]

The Commission recognises the potential utility of the PFR valuation approach that CS energy and IES have developed. The Commission intends to consider the development of an effective valuation and payment mechanism for PFR through the assessment of the *Removal of disincentives to the provision of primary frequency control* rule change.

## 3.4 Stakeholder views on the draft revised work plan

In response to the draft revised work plan published on 19 December 2019, stakeholders expressed strong support that the Commission investigate options to reward primary frequency response. A number of stakeholders recommended further investigation of specific mechanisms for PFR including bilateral contracts, a spot market, performance payments, fast frequency response, removing disincentives, and reforming causer pays.[85]

Snowy Hydro, CleanCo, Meridian Powershop and Fluence recommended moving straight to a market solution instead of implementing a mandatory PFR requirement.[86]

A number of stakeholders requested that the Commission provide further detail on the process and timing for the development and implementation of an incentive framework for PFR and the resolution of the sunset provision for the Mandatory PFR arrangements. [87]

> The activities listed in the work plan for calendar year 2020 are all supported, but these seem to be only a combination of broad research and matters associated with implementation of the existing three rule changes. The work plan has not yet indicated a clear design period for a way to reasonably procure PFC.
>
> [...]
>
> the AEC recommends a more dedicated focus upon a replacement to ERC0274.[...] In that respect, the workplan should identify specific deliverables, allocated to specific parties, by specific dates.

84 CS Energy, Submission to the *PFR rule changes* consultation paper, 31 October 2019, pp. 22-24

85 Stakeholder submissions to the draft determination: Fluence, p.6; Tesla, pp.3-5, Snowy Hydro, pp.2, 3, 6; and TasNetworks, p.1-2.

86 Stakeholder submissions to the draft determination: Snowy Hydro, p.2; CleanCo, p.1; Meridian Powershop, p.1; Fluence, pp.4, 6-7.

87 Submissions to the draft determination:AEC, p.4.; CleanCo, p.1; ERM Power, p.6; Origin, p.3; CS Energy, p.9; ENA, p.2; Fluence, p.6; Infigen, p.2.

A number of stakeholders reiterated the call for the work plan to incorporate an action for the power system frequency performance requirements to be reviewed and specified in a way that supports the development of any future arrangement for PFR. [88] As noted by the CEC:

> The CEC suggests that the development of the incentive framework through the upcoming AEMC workplan presents the need for analysis that will assist with the permanent PFR market development. The level of frequency control needed from the generation fleet now and in the future should be quantified as it will provide the AEMC with guidance for the framework development and will assist AEMO to develop an understanding of the quantity and locational spread of PFR required.

## 3.5 The revised frequency control work plan

In collaboration with the ESB and other market bodies and in response to stakeholder feedback, the Commission has updated the frequency control work plan consistent with this being a living document. The frequency control work plan was established through the *Frequency control frameworks review* to provide a vehicle for:

1. the AEMC and AEMO to implement the various actions to improve frequency performance in the NEM, and report on progress against those actions
2. the AEMC to further explore, and seek stakeholder input on, potential longer-term mechanisms for the procurement of a primary regulating response and other frequency services as the needs of the power system evolve.
3. the AEMC to consider, and consult with stakeholders on, how the frequency requirements in relation to the maintenance of a satisfactory operating state are specified in the NER and the frequency operating standard, which will include consideration of whether the NER or the frequency operating standard should:
    a. include a system standard in relation to the rate of change of power system frequency.
    b. prescribe in more detail the required frequency performance within the normal operating frequency band.

The frequency control work plan sets out the actions that the ESB and market bodies will undertake to understand the power system requirements for maintaining good frequency control and to reform the existing frequency control frameworks to meet these needs now and in the future.

This final determination includes a revised Frequency control work plan, Table 3.1, that reflects the work completed to date by the market bodies and outlines the plan for frequency reforms to 2023.

88 Submissions to the draft determination: CEC, p.6.; Delta, p.2.

### 3.5.1 Objectives

The reforms in the frequency work plan aim to deliver the following outcomes for the frequency control framework in the NEM:

- the expected frequency performance of the power system is specified in the Frequency operating standard,
- AEMO has adequate tools to control system frequency in accordance with the requirements of the Frequency operating standard,
- the obligations and incentives on market participants support the efficient investment in and operation of the national electricity system.

### 3.5.2 Principles

The actions detailed in the frequency control work plan are guided by the National Electricity Objective (NEO). In considering any changes to the regulatory and market frameworks, the Commission will consider whether the change 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 be guided by the following principles:

- **Promotes system security as a priority:** 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. Consideration will be given to the impact on system resilience and the ability to plan and model the power system. 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.
- **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.
- **The requirement that system frequency performance is specified in the Frequency operating standard:** The Frequency Operating Standards specifies, with the appropriate detail, the expected frequency performance of the power system. As the frequency control arrangements are revised to reflect the changing needs of the power system, the frequency operating standard may require updating to reflect the expectations for power system frequency control.
- **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.

### 3.5.3 The revised frequency control work plan

The frequency control work plan has been developed collaboratively by the ESB and market bodies. The dates associated with each action are intended to provide indicative guidance to stakeholders.

The work plan is intended to be a living document and will be further shaped by the findings of each stage as it is progressed, as well as incorporate any future rule change requests received that are related. In addition, the market bodies are working closely with the ESB on its *Post-2025 Market Design* project. This project will advise on a long-term fit for purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation.

The ESB published an issues paper in September for its *Post-2025 Market Design* project. This included discussion of key challenges for system security services such as the fact that the frequency of the power system is now at risk of not meeting the standard and, more importantly, is now showing inadequate response to disturbances that would normally be expected. The market bodies are working closely with AEMO on these issues.

The AEMC will continue to consult with key stakeholders through the technical working group that was established for the purpose of assessing the primary frequency response rule change requests. The working group will provide a valuable means for the ESB and market bodies to gain input and feedback on the progress and activities related to the objectives of the frequency control work plan.

In 2019, the COAG Energy Council tasked the ESB with providing advice on the implementation of interim measures to preserve reliability and system security in the NEM. This advice is due to the Council in March 2020. As part of this advice, the ESB is to work with the market bodies to develop a system security work plan. The frequency control work plan has informed the frequency component of this broader ESB system security work plan.

As requested by AEMO, the immediate steps include the implementation of a mandatory requirement for scheduled and semi-scheduled generators to provide PFR to support frequency control in the NEM in the interim. Through this workplan the ESB and market bodies commit to the development and implementation of enduring frequency control frameworks. This includes future changes to the NER to provide for an incentive-based mechanism for the provision of PFR to support effective frequency control in the national electricity system prior to June 2023.

The revised frequency control work plan is set out in Table 3.1.

**Table 3.1: The revised frequency control work plan**

| TIMING | ACTION |
|---|---|
| **COMPLETED**<br>These actions were completed between 19 December 2019 and the time of publication of this final determination, 26 March 2020. | |
| 19 December 2019 | The AEMC published the draft determination on the consolidated *Mandatory primary frequency response* and *Primary frequency response requirements* rule changes. |
| 1 January 2020 | The *Monitoring and reporting on frequency control framework* rule commenced:<br>• AEMO now produces weekly and quarterly frequency performance reports, as required by the new rule.<br>• AER now produces quarterly FCAS market performance reports, as required by the rule. |
| 25 February 2020 | AEMO released the *Market Ancillary Service Specification and Causer Pays Procedure Draft Determination* and *Draft Report*. |
| 26 March 2020 | The AEMC published the final determination on the consolidated *Mandatory primary frequency response* and *Primary frequency response requirements* rule changes (this document). |
| **IMMEDIATE TERM (PRESENT — DECEMBER 2023)**<br>During this period, AEMO continues with a range of actions to better understand the current and future frequency control needs of the power system and takes steps towards addressing these needs through a revision of current AEMO operating practices and procedures.<br>This period also contains the AEMC's assessment of the *Mandatory primary frequency response* rule change and the *Removal of disincentives to primary frequency response* rule change. The AEMC is focused on the implementation of a mandatory requirement for scheduled and semi-scheduled generators to provide PFR to support frequency control in the NEM in the interim through the *Mandatory primary frequency response* rule change. However, through the *Removal of disincentive to primary frequency response* rule change and other related rule change requests received, the AEMC will investigate the appropriateness of the existing incentives for PFR during normal operation and amend these arrangements as | |

<table>
<tr><th>TIMING</th><th>ACTION</th></tr>
<tr><td colspan="2">required.<br>In Q2 2020, the Commission will work with stakeholders and AEMO on the detailed directions for this rule change which will consider:<br>• the arrangements for allocation of costs associated with regulation services — 'causer-pays'<br>• the potential development of additional complementary measures to effectively remunerate providers of primary frequency response<br>• how best to meet the future needs of the power system<br>• interaction with the arrangements in the Mandatory primary frequency response rule including the sunset provision.<br>This will also be an input into the ESB’s post 2025 market design work.</td></tr>
<tr><td>Ongoing</td><td>AEMO commissioned a further review of AGC systems in July 2019, which may result in further adjustments to AGC tuning.</td></tr>
<tr><td>Ongoing</td><td>AEMO, the AEMC and the AER began a NEM virtual power plant trial program in November 2018 to support an understanding of the technical and regulatory requirements associated with virtual power plants providing FCAS, as well as energy and network support services. This work will inform AEMO’s review of the MASS and the AEMC’s ongoing work on removing barriers to distributed energy resources participating in wholesale markets.</td></tr>
<tr><td>Ongoing</td><td>AEMO continues its review of contingency FCAS quantities, including:<br>• The staged reduction of NEM load relief factors<br>• Review of maximum switch reserve quantity<br>• Consideration of regional FCAS requirements<br>• Minimum technical requirements for Regulation FCAS<br>In December 2019, AEMO reduced the assumed mainland load relief to 0.5%.</td></tr>
<tr><td>Ongoing</td><td>AEMO reports on the outcomes of the actions set out above as results become available through its Ancillary Services Technical Advisory Group, Frequency Control Working Group and/or published reports.</td></tr>
<tr><td>Q2 2020</td><td>AEMO evaluates the requirement to submit a rule change request to:</td></tr>
</table>

| TIMING | ACTION |
|---|---|
| | • allow Small Generation Aggregators to classify small generating units as market ancillary service generating units for the purposes of providing market ancillary services, and<br>• to clarify that Market Ancillary Service Providers are able to satisfy their obligations to provide market ancillary services through enabling small generating units.<br>This action will be informed by the outcomes of the NEM virtual power plant trial program described above. |
| Q1 2020 | AEMO to publish its Renewable Integration Study report which will quantify the technical renewable penetration limits of the power system for a projected generation mix and network configuration in 2025. |
| April 2020 | Generator self-assessments begin. |
| 9 April 2020 | AEMO releases interim PFRR for consultation. |
| 29 April 2020 | AEMO publishes the *Market Ancillary Service Specification and Causer Pays Procedure Final Determination* and *Final Report.* |
| May 2020 | AEMO publishes Interim Primary Frequency Response Requirements. |
| Q2 2020 | AEMC publishes directions paper for the *Removal of disincentives to primary frequency response* rule change. |
| 4 June 2020 | The substantive elements of the *Mandatory primary frequency response* rule commence. |
| Q2-Q3 2020 | AEMO to provide technical advice to support the AEMC's assessment of policy options for the *Removal of disincentives to primary frequency response* rule change |
| Q4 2020 | AEMO reports on the requirement to add or amend performance objectives for frequency control in the NEM. |
| September2020 | AEMC publishes on the *Removal of disincentives to primary frequency response* draft determination. |
| December 2020 | AEMC publishes *Removal of disincentives to Primary frequency response* final determination. |
| Q1 2021 to 2023 | If necessary, AEMO works with stakeholders to implement the changes to systems and procedures as required by the *Removal of disincentives to primary frequency response* rule. |
| 4 June 2023 | Sunset for the Mandatory PFR requirement (subject to amendment or removal in the *Removal of disincentives to Primary frequency response* final determination). |

<table>
<tr><th>TIMING</th><th>ACTION</th></tr>
<tr><td colspan="2">OTHER RELATED WORK</td></tr>
<tr><td colspan="2">In addition to the above, as noted earlier, AEMO, the AER, the ESB and the AEMC are all working together in coordination with the ESB’s Post-2025 Market Design plan. This work includes looking at system security and resilience, including such key challenges as:<br>
• identifying which additional services may be required given the changing mix of supply with more non-synchronous generation<br>
• determining how the market can efficiently procure the system services needed, valuing those services in ways which drive both the investment needed and their efficient delivery<br>
• providing incentives to minimise the cost of those services and provide for innovation and new technology in their provision<br>
The development of frequency control markets and frameworks through this work program will therefore need to be undertaken coherently with the ESB’s work. As per the Post-2025 Market Design Forward Work Program, the ESB is scheduled to develop the rule changes required to implement its recommended changes to existing market design throughout 2021 with finalisation of these changes by 1 July 2022.<br><br>
Throughout this period, AEMO continues monitoring and reporting on power and generation system behaviour, which informs the work of all market bodies on enduring solutions for frequency control.</td></tr>
</table>

# 4 OVERVIEW OF THE FINAL RULE

This chapter provides an overview of the final rule, which is a more preferable final rule, including the introduction of a mandatory PFR requirement for all scheduled and semi-scheduled generators who have received a dispatch instruction to generate to a volume greater than 0 MW to operate their plant in accordance with the P*rimary frequency response requirements* as applicable to that plant. The final rule includes provisions for the mandatory requirement to commence on 4 June 2020 and be removed after a period of three years on 4 June 2023, given arrangements to incentivise PFR will be considered through the assessment of the *Removal of disincentives to primary frequency response* rule change and any other related rule change requests received.

As described in Chapter 3, this final determination is part of the Commission's ongoing frequency control work plan. Through the work plan, the Commission will work with the ESB and other market bodies to implement enduring frequency control arrangements that support a secure and resilient power system while providing adequate incentives to encourage economically efficient investment in and operation of generation plant in the NEM. The Commission is committed to the development of arrangements to effectively incentivise primary frequency response prior to the sunset for the mandatory PFR.

The following sections provide an overview of the key elements of the final rule including:

- the mandatory PFR requirement
- the process for exemption or variation to the performance parameters for the provision of PFR
- the arrangements for implementation of the mandatory PFR requirement
- other changes to the NER that relate to the provision of PFR by market participants in the NEM.

## 4.1 The Mandatory PFR requirement

The final rule places an obligation on all scheduled and semi-scheduled generators who have received a dispatch instruction to generate a volume greater than 0 MW, to operate their plant in accordance with the performance parameters set out in the *Primary frequency response requirements* as applicable to that plant. AEMO is responsible for the development of the *Primary frequency response requirements* in consultation with market participants.

The following sections provide an overview of the Commission's final determination for:

- the mandatory requirement for all scheduled and semi-scheduled generators to provide PFR
- the specification of the technical requirements for PFR

Further detail on the Commission's considerations in relation to the introduction of the mandatory PFR requirement, and its analysis and considerations of submissions received, are set out in Appendix A.

### 4.1.1 A mandatory requirement for all scheduled and semi-scheduled generators

The Commission's final rule includes a requirement in Chapter 4 of the NER that all registered scheduled and semi-scheduled generators who have been given a dispatch instruction to generate to a volume greater than 0 MW be required to comply with the PFRR.[89] AEMO has advised the AEMC that this reform will meet the immediate system need for effective frequency control in the NEM.

The Commission considers this change to the NER is justified by the need to improve and maintain the security and resilience of the national electricity system to meet AEMO's concerns, but also recognises that the final rule will not adequately value or reward frequency response from capable generating units. The Commission considers that in the longer term there should be incentives and rewards for providing primary frequency response. Schedule 2 of the final rule effectively applies a sunset to the mandatory obligation on generators to provide PFR by reversing the changes made to the rules to introduce the mandatory framework on 4 June 2023. This creates a clear signal that the Commission is committed to the development of an arrangement that appropriately incentivises primary frequency response provision to be put in place prior to the sunset. This will be achieved through the assessment of the *Removal of disincentives to primary frequency response* rule change as well as any other relevant rule change requests received.

#### A lower bound on the deadband to be set out in the NER

The final rule introduces a new *primary frequency control band* of 49.985Hz to 50.015Hz (or such other range as specified by the Reliability Panel in the frequency operating standards), which sets a lower bound on the deadband to which individual generators must comply under the PFRR. The Commission considers that the *primary frequency control band* is a key variable associated with the final rule, which has implications for both system operation and the operation of the markets for electricity and ancillary services in the NEM. In the absence of a clearly defined frequency performance standard in the FOS, the Commission has determined that the minimum bound for the *primary frequency control band* be specified in the NER, and not subject to full discretion by AEMO in the PFRR.

#### No requirement to maintain additional stored energy

The Commission has also specified in the final rule that the PFRR cannot require generators to maintain additional stored energy for the purposes of providing frequency response in accordance with the requirements of the PFRR. The Commission acknowledges that AEMO did not propose to include a requirement in the PFRR that generators maintain headroom (stored energy) as part of its proposed rule. However, the PFRR is subject to change, and any future obligation which results in a large cross-section of the generating fleet maintaining stored energy would likely impose substantial costs on generators that outweigh the additional benefits this might provide to the security of the power system. This aspect of the

89 The Commission will be recommending to the COAG Energy Council that this requirement be classified as a civil penalty provision under the National Electricity (South Australia) Regulations. The Commission's final rule would result in generators with a nameplate rating less than 30MW not being required to provide PFR unless registered as a scheduled or semi-scheduled generator.

final rule will provide greater clarity and certainty to generators and will limit the likelihood of substantial unwarranted costs being incurred by generators in the future.

**No requirement to install or modify monitoring equipment**

In response to stakeholder concerns made on the draft rule, the final rule also provides that the PFRR must not require the installation or modification of monitoring to monitor and record the response of the relevant generating system to changes in power system frequency for the purpose of verifying compliance with the mandatory PFR requirement (new clause 4.4.2A(c)(2)) The final rule requires AEMO to document the details of the information to provided by Generators to verify compliance with the PFRR, including any compliance tests or audits for the purpose of verifying compliance through its PFRR.

**Treatment of battery energy storage systems**

In response to stakeholder concerns, the Commission has considered the impact of a mandatory PFR requirement on the operation of battery energy storage systems. Under the final rule, when generating (discharging), battery energy storage systems will be treated the same as other scheduled and semi-scheduled generators and will be required to provide PFR in accordance with the conditions set out in the PFRR. When operating in a charging mode, battery energy storage systems will be treated the same as other scheduled loads, which are not required to provide PFR.

- However, unlike other generation technologies, battery energy storage systems are capable of providing a frequency response when they are neither charging nor discharging, ie neither supplying nor consuming energy from the grid. Under the final rule, generators that are not dispatched in the energy market to generate electricity are not required to operate in a frequency response mode in accordance with the PFRR. As such, the final rule includes a provision that generators are only required to provide PFR when they have received a dispatch instruction to generate at a volume greater than 0 MW. The Commission considers that the application of the mandatory PFR requirement to battery energy storage systems that are not dispatched to generate electricity would be discriminatory, as other generation technologies cannot provide PFR unless they are online and generating.[90]

### 4.1.2 The specification of the technical requirements for PFR

The final rule includes a requirement for AEMO to develop and publish the *Primary frequency response requirements* to specify the performance parameters that apply to generators in respect of the provision of PFR. AEMO submitted to the Commission an initial draft of the PFRR for consideration alongside its rule change request. AEMO has informed the Commission that it will consult with stakeholders and take into account stakeholder feedback provided through the rule change process in refining this document. AEMO will also need to update the draft PFRR to reflect this final rule. The transitional provisions in the final rule require AEMO to publish a draft interim PFRR by 9 April and then consult on this draft, before

90 This is consistent with the approach taken by the US Federal Energy Regulatory Commission in its 2018 ruling on Primary frequency response. Ref. RM16-6-000, pp.126 - 127.

finalising the interim PFRR by 4 June 2020. The finalised document will form the interim PFRR, which will be adapted and refined over time. AEMO is also required under the final rule to make the first PFRR required under new clause 4.4.2A(a) of the Rules by 1 December 2021. Any changes to the PFRR after this date must be undertaken through the Rules consultation procedures.

The final rule introduces a new clause 4.4.2A(b) which requires that the PFRR include:

- A requirement that Scheduled Generators and Semi-Scheduled Generators set their generating systems to operate in frequency response mode within one or more primary frequency response performance parameters (which may be specific to different types of plant), which must include maximum allowable deadbands, and may include but not be limited to; droop; and response time.
- The conditions or criteria on which a generator may request and AEMO may approve a variation or exemption from any applicable primary frequency response parameters, and the process and timing for an application for a variation or exemption.
- Details of information to be provided to AEMO to verify compliance with the PFR.

With respect to the PFRR, the final rule includes provisions that:

- AEMO must follow the Rules consultation procedures to make any substantive change to the PFRR.
- AEMO must publish and maintain on its website a register of generators who have been granted a variation or exemption from the performance parameters set out in the PFRR.

The final rule also provides that clause 5.3.9 (which sets out the requirements for generators proposing to alter a connected generating system) does not apply in relation to any modifications made to a generating system by a Scheduled Generator or Semi-Scheduled Generator in order to comply with the PFRR.

### 4.1.3 Changes between the draft and final rule

The main changes in the final rule in relation to the mandatory requirement to provide PFR are:

- Cl 4.4.2A(b) has been amended in the final rule so that while the performance parameters specified in the PFRR by AEMO must still include maximum allowable deadbands, they may include (but are not limited to):
  - droop; and
  - response time.
- Cl 4.4.2A(c) includes a new provision that confirms that the PFRR must not require a Generator to install or modify monitoring equipment to monitor and record the provision of PFR to verify compliance with the mandatory PFR requirement set out in Cl 4.4.2(c1).
- The final rule also provides that clause 5.3.9 (which sets out the requirements for generators proposing to alter a connected generating system) does not apply in relation to any modifications made to a generating system by a Scheduled Generator or Semi-Scheduled Generator in order to comply with the PFRR.

## 4.2 Exemptions from the PFR requirement

The final rule includes an exemption framework that is based on the approach set out in AEMO's proposed rule. The final rule introduces a new clause 4.4.2A(b)(2) which requires that the PFRR include provision for Generators to request, and AEMO to approve, an exemption or variation from the requirements specified by AEMO in the *Primary frequency response requirements* applicable to their generating system. AEMO is the appropriate party to consider the exemptions since they are the system operator and so have the technical information required to assess both costs, as well as the effect that the exemption would have on frequency performance. Information provided to AEMO as part of an application for variation or exemption under clause 4.4.2B(a)(4) is confidential information.

The final rule also introduces a new clause 4.4.2B which sets out the following criteria which AEMO must have regard to in considering such a request:

(1) the capability of the generating system to operate in frequency response mode;

(2) the stability of the generating system when operating in a frequency response mode and the potential impact this may have on power system security;

(3) any other physical characteristics of the generating system which may affect its ability to operate in frequency response mode, including (but not limited to) dispatch inflexibility profile, operating requirements, or energy constraints; and

(4) whether the scheduled generator or semi-scheduled generator has been able to establish to AEMO's reasonable satisfaction that the implementation of the primary frequency response parameters applicable to that scheduled generator's or semi-scheduled generator's generating system will be unreasonably onerous having regard to, amongst other things:

(i) the likely costs of modifying the generating system to be able to operate in a frequency response mode; and

(ii) the likely operation and maintenance costs of operating the generating system in frequency response mode

relative to the revenue earned from, the provision of energy and market ancillary services by the generating system in relation to its operation in the *NEM* during the 12 months prior to the date of the application for exemption or variation, as applicable.

The exemption framework in the final rule is designed to avoid excessive costs that may otherwise be incurred through the application of the mandatory PFR requirement to the entire generation fleet. This is consistent with AEMO's proposed rule, which exempted Generators from the PFR requirement where it was not feasible for their generating systems to comply.[91] The final rule is designed to meet the immediate system security need for improved frequency performance while avoiding excessive associated costs.

The Commission expects that the costs for each generator to meet the performance parameters for PFR will vary. Some generation plant are likely to meet the performance parameters for PFR with minimal need for plant changes. The capability from these generators can be utilised for a relatively low upfront implementation cost.

Other generation plant may require more significant plant upgrades and control system tuning in order to provide PFR in accordance with the technical requirements. In the absence of an exemption framework some generators could be forced to incur substantial costs for plant upgrades to comply with the PFR requirement.

The Commission considers that in some cases the upfront and operating costs of requiring a generator to comply with the PFRR may be challenging to absorb and as such may represent a business risk. While if the costs for all businesses are the same, then these can be passed on to consumers jointly, the Commission still has concerns about the 'edge' cases where there may be a disconnect between when the costs would be incurred and when they would be recovered. If costs were challenging to absorb for a short time period, then this would constitute a business risk and potentially risks to reliability. Therefore, the exemption principles include provision for a Generator to request a variation or exemption from the requirements of the PFRR on the grounds that compliance would be unreasonably onerous, based on an assessment against their revenue.

The exemption principles in the final rule provide a transparent framework to avoid excessive compliance costs for eligible generation plant while still delivering on the system security and frequency control objectives. The proposed exemption framework provides a degree of flexibility for AEMO in administering the exemption process while at the same time setting out a series of principles to improve the transparency of the exemption process.

Consistent with AEMO's proposed rule, the final rule also introduces a new clause 4.4.2A(d) to require that AEMO publish on its website, and maintain, a register of generators who have been granted an exemption or variation from any primary frequency response parameters in the PFRR.

Further detail on the Commission's considerations in relation to the framework for exemption or variation to the technical requirements for mandatory PFR and its analysis and considerations of submissions received are included in Appendix B.

### 4.2.1 Changes between the draft and final rule

The main changes in the final rule in relation to the exemption framework are:

- The exemption principles set out in Cl 4.4.2B(a) have been re-ordered in the final rule.
- The exemption principles that relate to upfront and ongoing costs have been combined under the new sub-paragraph (4). This sub paragraph has been revised to reflect the intent that an applicant for an exemption or variation to the PFRR should establish, to

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

AEMO's satisfaction, that operation in accordance with the default requirements of the PFRR will be unreasonably onerous. The application for an exemption or variation should have regard to:

- (i) the likely costs of modifying the *generating system* to be able to operate in *frequency response mode;* and
- (ii) the likely operation and maintenance costs of operating the *generating system* in *frequency response mode*,

The consideration of whether the likely upfront and ongoing costs are unreasonably onerous shall be made relative to the revenue earned from the provision of *energy* and *market ancillary services* by the *generating system* in relation to its operation in the *NEM* during the 12 months prior to the date of the application for exemption or variation, as applicable.

- The final rule includes a new sub-paragraph in clause 4.4.2B to clarify that cost information provided by a generator to AEMO as part of a request for an exemption or variation to the requirements under the PFRR is confidential information.

## 4.3 Implementation and transitional arrangements

The final rule includes transitional provisions that set out the arrangements for the implementation of the mandatory PFR requirement. The transitional rules in chapter 11 of the NER include a requirement for AEMO to prepare interim *Primary frequency Response requirements* to apply from 4 June 2020 (which is the date the provisions that introduce the mandatory framework will commence). AEMO has confirmed with the AEMC that it is comfortable with this date.

In addition to the performance parameters for the provision of PFR, the interim *Primary frequency response requirements* also document AEMO's process for coordinating changes to generation plant associated with activation of the frequency response mode as intended by the *Mandatory primary frequency response* rule. This process would also include the date by which each generator must comply with the performance parameters set out in the *Primary frequency response requirements*.

The Commission acknowledges stakeholder concerns in relation to the coordination of plant changes associated with the implementation of the mandatory primary frequency response requirement. In particular, stakeholders have expressed concern that the hasty or uncoordinated implementation of changes to generator control systems may pose risks to generation plant and power system security due to the proposed deadband of ±0.015Hz being untested in the history of the NEM. To address these concerns, the final rule requires AEMO to publish a draft of the interim *Primary frequency response requirements* by 9 April 2020 (which can take into account the final rule), and provide stakeholders at least 20 business days to make submissions on the draft. AEMO is required to take into account any submissions received, and to develop and publish on its website interim *Primary frequency response requirements* by 4 June 2020.

### AEMO may undertake consultation prior to the commencement date of the rule

The Commission recognises that AEMO has identified the reinstatement of effective frequency control through the mandatory PFR requirement as a system security priority to be implemented in the shortest reasonable time frame.[92] Given the potential consequences of the ongoing lack of effective frequency control in normal operating conditions, the Commission has made a final rule that includes allowance for AEMO to commence consultation on the interim *Primary frequency response requirements* prior to the commencement date for the amending rule. While the actual timings of the consultation process are a matter for AEMO, the final rule requires that the interim *Primary frequency response requirements* is finalised and published on AEMO's website prior to the commencement date for the mandatory primary frequency response requirement on 4 June 2020.

### Consideration of reimbursement for upfront costs

AEMO's proposed rule included transitional arrangements for Generators to submit a claim for reimbursement of costs associated with plant upgrades to become compliant with the *Primary frequency response requirements*, and for AEMO to recover its associated costs through participant fees.[93]

Compensation is not typically provided to affected parties for the costs associated with complying with an amendment to the NER. Furthermore, the costs for plant upgrades and control system changes are expected to be relatively minor and manageable for most affected generators. Where the costs of plant upgrades are more substantial, it is intended that a generator will be eligible for a full or partial exemption from the requirement which will avoid or reduce the upfront costs.

Therefore, the final rule:

- does not include any transitional arrangements for affected generators to be directly reimbursed for plant upgrade costs;
- does not include any transitional arrangements for AEMO to recover such associated costs through market participants fees.

Further detail on the Commission's considerations in relation to the process and timing for the implementation of the mandatory PFR requirement and its analysis and considerations of submissions received is included in Appendix C.

## 4.3.1 Changes between the draft and final rule

There are no changes between the draft and final rule that relate to implementation and transitional arrangements.

92 AEMO, Mandatory Primary Frequency Response - Electricity rule change proposal, 16 August 2019, p.41.

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

## 4.4 Other proposed changes

AEMO and Dr. Sokolowski each proposed a number of other changes to the NER that relate to the provision of PFR. The Commission's conclusions on each of these proposed changes are set out below.

- **Clause 3.15.6A(k) — Contribution factors for the allocation of costs for regulating services**

  The final rule revises NER clause 3.15.6A(k)(5) and 3.15.6A(k)(7) to clarify that a scheduled participant or a semi-scheduled generator will not be assessed as contributing to deviations in the frequency of the power system if within a dispatch interval it achieves its dispatch target at a uniform rate subject to the provision of PFR by that Participant in accordance with the PFRR.

- **Clause 4.9.4 — Dispatch related limitations on generators**

  The final rule includes changes to clause 4.9.4(a)(3), including the addition of clause 4.9.4(a)(3A) stating that both scheduled and semi-scheduled generators may send out energy as a consequence of its operation in a frequency response mode to adjust power system frequency in response to power system conditions.

- **Clause 4.9.8 — Compliance with a dispatch instructions**

  The final rule includes changes to clause 4.9.8 to clarify that operating a plant in a frequency response mode is compatible with a generators' obligation to follow its dispatch instructions. In particular, new clause 4.9.8(a1) states that a scheduled Generator or Semi-scheduled Generator would not be taken to have failed to comply with a dispatch instruction as a consequence of its generating unit operating in frequency response mode in order to adjust power system frequency in response to power system conditions.

- **Clause S5.2.5.11 — Generator technical performance standards for frequency control**

  The final rule includes a note after S.5.2.5.11(b)(2) and S5.2.5.11(c)(2) that provides additional clarity in relation to the operational requirement for frequency control as set out in the final rule clause 4.4.2(c1). The note states that:

  - Clause 4.4.2(b) of the Rules sets out the obligations on Generators in relation to compliance with the technical requirements in S5.2.5.11, including being capable of operating in frequency response mode
  - Clause 4.4.2(c1) of the Rules sets out the obligations on Scheduled and Semi-Scheduled Generators in relation to the *Primary frequency response requirements*.

- **Clause S5.2.5.14 — Generator technical performance standards for active power control**

  The Commission considers Dr. Sokolowski's proposed change to S5.2.5.14 does not provide a benefit in terms of improving the specification or clarity of the frequency control capability for connecting generators. As such, the final rule does not amend S5.2.5.14.

Dr. Sokolowski also proposed changes to certain clauses in the rules relating to system security more generally, including proposed changes to:

- **NER Clause 4.3.1 — AEMO's responsibilities for maintaining power system security**

  The Commission notes AEMO has an existing obligation to maintain and improve power system security under S49(1)(e) of the NEL. The NEL requirement is also referenced in the NER clause 4.1.1(b). In the context of the existing obligations, the proposed change does not constitute a material benefit in terms of the understanding or the application of the NER.

  The final rule does not include any revision to NER clause 4.3.1.

- **NER Clause 5.20B.5 —inertia support activities and the definition of inertia**

  Clause 5.20B.5(a) of the NER allows for frequency control services, from inverter connected plant or otherwise, to be considered as 'inertia support activities' subject to approval by AEMO. The Commission notes that the existing arrangement for inertia support activities are inclusive of fast frequency response from inverter connected plant under the term, frequency control services. Therefore, the Commission does not consider there to be a benefit in making the proposed change by Dr. Sokolowski to clause 5.20B.5(a).

  The Commission considers that the existing definition of inertia reflects the current operational practice that differentiates between physical inertia provided by synchronous machines and fast frequency response provided by inverter connected plant. The proposed change would remove that distinction and result in inertia being a more general term that included any plant that is able to oppose a change in power system frequency.

  The final rule does not include any change to Clause 5.20B.5 nor to the Chapter 10 definition of inertia.

Further detail on the Commission's considerations in relation to the other proposed changes to the NER and its analysis and considerations of submissions received is included in Appendix D.

### 4.4.1 Changes between the draft and final rule

There are no changes between the draft and final rule for this aspect.

# 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 |
| DC | Direct current |
| DNSP | Distribution network service provider |
| DRP | Dispute resolution procedure |
| EFCS | Emergency frequency control scheme |
| FCAS | Frequency control ancillary service |
| Hz | Hertz |
| MASS | Market ancillary service specification |
| MCE | Ministerial Council on Energy |
| NEL | National Electricity Law |
| NEMDE | National electricity market dispatch engine |
| NEO | National electricity objective |
| NOFB | Normal operating frequency band (49.85 Hz — 50.15 Hz) |
| NSP | Network service provider |
| OFGS | Over frequency generation shedding scheme |
| PFCB | Primary frequency control band |
| PFR | Primary frequency response |
| PFRR | Primary frequency response requirements |
| TNSP | Transmission network service provider |
| UFLS | Under frequency load shedding scheme |

# A A MANDATORY REQUIREMENT FOR ALL GENERATORS TO PROVIDE PRIMARY FREQUENCY RESPONSE

The Commission has made a final rule, which is a more preferable rule, to place an obligation on all scheduled and semi-scheduled generators to provide primary frequency response in accordance with the requirements of AEMO's *Primary frequency response requirements* (PFRR). AEMO is responsible for the development of interim and then the ongoing PFRR in consultation with market participants. The requirement for all scheduled and semi-scheduled generators to provide primary frequency control has been informed by advice from AEMO, supported by expert advice from Dr John Undrill.

It is possible for eligible generators to obtain an exemption from this requirement or a variation of the PFRR in relation to its generating system, which is discussed in Appendix B.

This appendix explores the application of a mandatory obligation on all scheduled and semi-scheduled generators to provide primary frequency response and sets out further detail on the Commission's final rule in relation to:

- the requirement under chapter 4 of the NER for scheduled and semi-scheduled generators to comply with the requirements of the PFRR when they receive a dispatch instruction to generate to a level above zero MW
- the required content of the PFRR to be developed by AEMO
- the inclusion of a new *primary frequency control band* in Chapter 10 of the NER which defines the minimum deadband to which AEMO could prescribe on an individual generator through the PFRR
- the inclusion of a provision in chapter 4 of the NER to clarify that the PFRR cannot require generators to maintain headroom as a condition of complying with the requirements of the PFRR, or to install or modify monitoring equipment to monitor and record the response of the relevant generating system to changes in frequency for the purpose of verifying compliance with the PFRR
- interactions with generator performance standards.

## A.1 Mandating PFR requirement to achieve a desired frequency performance in the power system

The Commission's more preferable final rule:

- creates an obligation on each Scheduled Generator and Semi-Scheduled Generator to operate its generating system in accordance with the PFRR as applicable to that generating system
- clarifies that compliance with the above obligation does not require a Scheduled Generator or Semi-Scheduled Generator to maintain additional stored energy in its generating system for this purpose or to install or modify monitoring equipment

- creates an obligation on AEMO to develop and publish the PFRR in accordance with the Rules consultation procedures
- sets out the content of what the PFRR must include

## A.2 Proponents' views

### A.2.1 AEMO's views

**Mandatory primary frequency response**

In its rule change request, AEMO proposed that the obligation to provide PFR apply to all technically capable generating systems registered to participate in the NEM. AEMO's rationale for this approach is that it would:[94]

- reduce the frequency response burden and related costs on each individual generating unit
- provide geographic diversity of frequency response and increase system resilience to contingency events
- assist AEMO's efforts to accurately model the power system and plan for contingency events
- align the operation of the NEM with international best practice for power system operation.

AEMO acknowledged that the implementation of a mandatory PFR requirement would result in eligible generation plant incurring both upfront costs and ongoing costs in order to comply with this obligation.[95] However, AEMO considered that these costs are expected to be significantly less than the costs associated with the risks to system security that are associated with the continuation of poor frequency control in the NEM as well as the potential for further degradation in the absence of some requirement for increased PFR.

AEMO's proposal is supported by advice provided to AEMO by Dr. John Undrill that an obligation to provide PFR should apply to all generating systems, to the extent that it is practical to do so.[96] Dr. Undrill noted that this approach is intended to be a conservative and prudent approach to maintaining system security and resilience within a power system that is undergoing rapid technological transformation.

AEMO's proposed rule sought to require all capable scheduled and semi-scheduled generating units to provide PFR once frequency moves outside a defined frequency band. AEMO suggested that effective control and resilience of the power system would be achieved with a narrow response deadband. AEMO suggested 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

94 AEMO, Submission on the consultation paper, pp.3-4.

95 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp. 55-59.

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

the NEM.[97] Therefore, as soon as frequency moves above, or below 50 Hz by 0.015Hz the generators would automatically provide PFR.

In particular, AEMO considered that a narrow response deadband would:[98]

- 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.

AEMO's rule change request did not quantify a target frequency performance outcome rather it was based on the operational goal of requiring primary frequency response in relation to a narrow deadband from all capable generation plant.

AEMO considered that this approach to be the best way to address existing power system frequency issues. AEMO noted in its rule change request that alternative approaches were not feasible:

- narrowing the normal operating frequency band (NOFB) in the FOS would not deliver effective frequency control in the absence of the development of an effective tool to control frequency during normal operation.[99]
- revising the FOS and introducing a new market or performance-based mechanism at this time is also not appropriate, as such a policy approach would lead to a delayed implementation of a solution to the immediate power system frequency issues.

#### Application of obligation

AEMO did not propose to apply a capacity threshold as to which generators would be required to provide primary frequency response. However, AEMO suggested that the requirements should only apply to scheduled and semi-scheduled generators, which effectively limits the obligation to generators with capacity greater than 30MW.

AEMO's proposed rule included 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.

#### Primary Frequency Response Requirements

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). AEMO would prepare the PFRR in accordance with the rules consultation procedures.[100]

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

98 Ibid.

99 AEMO, Mandatory primary frequency response - Electricity rule change proposal, p.39.

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

AEMO's rule change request provided an overview of the technical performance parameters that it intends to specify in the PFRR.[101] AEMO provided an update to the draft PFRR in October 2019. AEMO proposed technical performance parameters are set out in Box 2 below.

AEMO proposed that the PFRR document would also set out:[102]

- 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
- the process for undertaking tests to demonstrate compliance with the PFRR
- the process for eligible generators to seek compensation

AEMO's rule change request indicated that it does not intend to prescribe requirements for the following technical criteria associated with the provision of PFR:[103]

- **Headroom** — there is no proposal for any requirement for additional headroom or energy reserve — 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 2.

AEMO also proposed that the generator performance standards under S5.2.5.11 in the NER be amended to remove any potential ambiguity with respect to the PFRR. This would make clear that generators are required to meet the requirements of the PFRR. In order to make it clear, the generator performance standards would be amended to remove the requirements in relation to the capability to set droop and deadband settings. In addition, it would be made clear in the access standards such that compliance with the standards would be 'subject to the *primary frequency response requirements*'.

AEMO considered that the capabilities required under the draft PFRR are not more onerous than the access standards in clause S5.2.5.11, or in other existing minimum access standards in clause S5.2.5.[104]

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

102 AEMO, Primary frequency response requirements — draft, August 2019, pp. 6-8

103 Ibid

104 AEMO, Submission on the consultation paper, pp.6-7.

## BOX 2: AEMO'S DRAFT PRIMARY FREQUENCY RESPONSE REQUIREMENTS

AEMO's proposed rule 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. In October 2019, AEMO provided an update to this initial PFRR, which included some revisions to the technical requirements, exemptions, and testing and modelling components of the PFRR. The following is a summary of AEMO's revised PFRR, which can be found on our website.

**Technical Requirements**

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

- there is no requirement to maintain additional headroom or stored energy 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 infrequency beyond the deadband, measured as a percentage of a generator's maximum operating level, is to be less than or equal to 5 per cent,
- the speed of response should be such that a 5 per cent change in active power is achieved in no more than ten seconds,
- the response should not be deliberately withdrawn or defeated 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 PFFR sets out a proposed process for Generators to demonstrate to AEMO their compliance with the technical requirements, including:

- The requirement and timeframe 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.

- 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 may be eligible for partial exemption from the PFRR if AEMO determines that full compliance with one or more of the Technical Requirements would affect power system security.
- 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 infrequency of ±5 per cent.

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 is 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.

Note: AEMO, Primary frequency response requirements - Revised draft, October 2019.

### A.2.2 Dr. Sokolowski's views

Dr Sokolowski’s rule change request also proposed a mandatory obligation that would be implemented through the NER and be intended to apply to all registered generation in the NEM.

Dr Sokolowski proposed 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.[105]

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:

1. 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.
2. 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.

Beyond the frequency response deadband, Dr Sokolowski's proposed rule does not specify any other technical criteria for PFR.

## A.3 Stakeholders' views on the consultation paper

The following sections summarise the main themes raised by stakeholders in response to issues covered by the consulation paper for the Mandatory primary frequency response rule.

### A.3.1 A mandatory approach versus an incentive-based or market-based approach

In submissions on the AEMC's consultation paper, the majority of stakeholders acknowledged the need for more effective control of power system frequency as identified by AEMO.[106] However, stakeholders held a diversity of views on the most appropriate means of addressing these issues.

A number of stakeholders suggested that a mandatory approach is likely to provide more PFR than is necessary and will result in higher costs when compared to a market based approach, which would lead to an economically efficient outcome through individual generator decision-making.[107]

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

106 Submissions on the consultation paper: Bruce Miller, p.1; Kate Summers, p.1; Stanwell, p.2; CS Energy, pp.1-2; Australian Energy Council, p.1; Delta Electricity, p.7; Ergon Energy and Energex, p.1; Fluence, p.2; AGL, p.1; Infigen, p.1; Tesla, p.3; Hydro Tasmania, p.1; Intelligent Energy Systems, p.2; Enel X, p.1; Tilt Renewables, p.1; MEA Group, p.1; Energy Networks Australia, p.1; TasNetworks, p.1; Neoen, pp.1-2; PIAC, p.3; AER, p.1.

107 Submissions on the consultation paper: AER, p. 2; CS Energy, pp. 9-10; ERM Power, p.2; Delta Electricity, p.7; Origin, p.2; ARENA, pp.2-3; Energy Australiatralia, p.2; Enel X, p.5; Stanwell, p.5; Snowy Hydro, p.3; Clean Energy Council, p.4; AGL, p.2; Infigen, pp.1-2; Tesla, p.4; Enel Green Power, p.1.

Tesla suggested that a better understanding of the PFR requirements of the NEM is necessary and that it would be beneficial to assess how a small number of generators providing quality PFR (fast response and high accuracy) that is also geographically dispersed, compares against the proposal for broad-based provision from a generating fleet with lower quality PFR.[108]

A number of stakeholders raised concerns that a mandatory approach is not likely to deliver effective outcomes with a changing energy mix. ERM Power suggested that the muting of the price signal through the introduction of mandatory primary frequency response may deter new suppliers from entering the market and influence existing suppliers to exit.[109] Origin considered that new entrants are unlikely to invest in frequency response capability beyond the mandated minimum if there is no financial incentive to do so.[110] Origin suggested that batteries are likely to play an increasingly important role in providing fast frequency response to support system security as synchronous generators exit the market, and incentives will be required for this future investment to be provided. This view was supported by Enel X who considered that a mandatory obligation to provide PFR is likely to adversely impact the business case for battery storage, at a time when governments, policy makers, businesses and AEMO are looking to batteries to help resolve multiple market issues.[111]

The Energy Efficiency Council suggested that the proposal would be a significant departure from the current direction of energy markets to use market-based signals and technology neutral approaches. This could have the effect of undermining the energy industry's confidence and increase the perception of the risks of investing in the NEM.[112] The Australian Energy Council also considered that mandating the provision of primary frequency response runs counter to good market principles and that the different levels of service provided by different technologies deserves differential reward.[113]

The Australian Energy Council and Alinta Energy both suggested that, if a mandatory approach is implemented, it should be accompanied by a sunset clause in the NER to be replaced by a more economically efficient approach at a future time.[114] The Australian Energy Council suggested that a sunset clause will force the industry to remain focused on the task and avoid the situation where a replacement has not been developed and implemented before the majority of PFR capability retires.

A number of stakeholders considered that a mandatory approach to the provision of primary frequency response is likely to be a preferred approach.[115] Kate Summers noted that frequency response requires local measurement and local control action and that dynamic response from plant cannot be centrally controlled through market dispatch targets due to communication latencies.[116] Resilience in the power system would be greatly improved

108 Tesla, Submission on the consultation paper, p.3.
109 ERM Power, Submission on the consultation paper, p.11.
110 Origin, Submission on the consultation paper, p.2.
111 Enel X, Submission on the consultation paper, p.1.
112 Energy Efficiency Council, Submission on the consultation paper, p.1.
113 Australian Energy Council, Submission on the consultation paper, p.5.
114 Submissions on the consultation paper: Australian Energy Council, p.9; Alinta Energy, pp.3-4.
115 Submissions on the consultation paper: Kate Summers, p.2; Bruce Miller, pp.1-2.

through reimplementing tight responsive governor systems that are not overridden by market dispatch instructions. Ergon Energy and Energex suggested that a more robust and resilient power system is likely to result from all generating systems working together.[117]

TasNetworks shared AEMO's concerns in relation to the forward costs likely to be incurred in the absence of measures to better control network frequency.[118] TasNetworks considered that any delay in responding to PFR issues risks increasing uncertainty and reducing network robustness in the face of the NEM's 'world leading' penetration levels of non-synchronous generation. This will only inevitably need to be countered with additional future conservatism in the design and operation of the power system, which is not in the long term interests of consumers.

TasNetworks considered there to be arguments in favour of both a mandatory approach and a market based approach.[119] The physical construct of the power system still relies on PFR to be available to operate in an acceptable manner. Contributions coming from a dispersed and broad range of providers will likely mean that the real cost of delivering the capability will trend towards something small. On this basis, a market approach may not be justified as long as the NER ensures ongoing capability from new technologies as they are progressively introduced over time. However, a market approach may have the benefit of encouraging investment in technologies or solutions that could deliver a better outcome for the power system in the long term.

Where a mandatory rule is implemented, some stakeholders proposed the application of a regulated payment in advance of the implementation of a more sophisticated remuneration mechanism.[120]

### A.3.2 Mandating a requirement for all generators to provide PFR

The majority of stakeholder responses raised concerns that any proposal to mandate the provision of primary frequency response could lead to substantial ongoing costs for generators, and that these costs are likely to vary substantially between different technology types.[121] Neoen suggested that the most responsive assets, such as batteries, will have to bear most of the operational load and will therefore be strongly impacted while slow responsive generation will see little of no consequence.[122] The economic impact on the most responsive plant will therefore be greatly increased.

This view was supported by Alinta Energy and Enel Green Power who considered that a proposal to mandate the provision of PFR would in effect create a perverse situation whereby those generator types which are perhaps best placed to respond will be penalised and those

116 Kate Summers, Submission on the consultation paper, p.2.

117 Ergon Energy and Energex, Submission on the consultation paper, p.1.

118 TasNetworks, Submission on the consultation paper, p.3.

119 TasNetworks, Submission on the consultation paper, p.4.

120 Submissions on the consultation paper: Alinta Energy, p.4; Hydro Tasmania, p.2; Energy Australia, p.2.

121 Submissions on the consultation paper: CS Energy, pp.2-4; ERM Power, p.8; Delta Electricity, p.13; Tilt Renewables, pp.1-2; Enel X, pp.5-6; Snowy Hydro, p.3; Enel Green Power, p.1; Intelligent Energy Systems, p.2.

122 Neoen, Submission on the consultation paper, pp.3-4.

generators who are worst placed to respond will be treated the same for the provision of a potentially inferior level of service.[123]

Neoen considered that a mandatory obligation on all generators would maximise the cost of implementation and acquire PFR from generators with poor capabilities or who would be economically impacted by operating in a frequency sensitive mode.[124]

The adverse commercial and economic impacts of the proposed mandatory PFR requirement are described in the stakeholder submissions from generators and owners of battery energy storage systems and include:[125]

- responsive generation will face a range of ongoing operational costs without adequate compensation or valuation of services provided
- the absence of an explicit mechanism to value PFR during normal operation may undermine the business case for plant that can provide this type of response most competitively
- the mandatory requirement does not allow for different generating plant to optimise plant performance for the generation of bulk energy and pay a fee for other plant to control frequency (via causer pays or otherwise).

**Ongoing operational costs**

Stakeholders suggested that the ongoing operational costs of a PFR requirement may include:

- the opportunity costs of providing a primary frequency response,
- the utilisation costs of providing a primary frequency response, including wear and tear and costs of movement enablement.

ERM Power noted that generators incur opportunity costs when preserving capacity to provide a frequency response.[126] Opportunity costs may come in the form of forgone revenue when preserving headroom to provide a raise response when the energy market price is above the generator's marginal cost, or maintain a high output in order to provide a lower response when the energy market price is below the generator's marginal cost.

CS Energy noted that the proposed rule does not require generators to preserve headroom and that this would thereby not impose unnecessary opportunity costs on the cheapest generators.[127] However, both the Australian Energy Council, CS Energy and Stanwell suggested that this could lead to a number of other issues:[128]

- the physical response of the power system will be dependent on opportunistically stored energy, which will be random on the basis of market dispatch and other matters

123 Submissions on the consultation paper: Alinta Energy, pp.2-3; Enel Green Power, p.1.

124 Neoen, Submission on the consultation paper, p. 3.

125 Submissions on the consultation paper: Neoen, p.1; Origin, p.2; ARENA, p.4; MEA Group, p.2; Australian Energy Council, pp.5-6; Fluence, p.2; Alinta Energy, p.2; Tesla, pp.4-5; Energy Efficiency Council, pp.1-2; Enel X, pp.5-6; Clean Energy Council, p.2; Infigen, p.2-6; Delta Electricity, p.13.

126 ERM Power, Submission on the consultation paper, p.8.

127 CS Energy, Submission on the consultation paper, p.9.

128 Submissions on the consultation paper: Australian Energy Council, p.6; CS Energy, p.9; Stanwell, p.4.

- the lack of raise response from most renewable generators will mean that it is likely that generators as a whole will respond much more effectively to high rather than low frequencies, causing a lopsided frequency performance and accumulated time error
- generators will have an incentive to avoid the burden of compliance by intentionally operating without stored energy, transferring the burden on to other generators
- those generators that are enabled in the contingency FCAS markets will be called upon foremost in the provision of a primary frequency response, which will mean that contingency reserves are drawn upon pre-contingency.

The provision of mandatory primary frequency response will also increase utilisation costs from complying generation plant. Stanwell considered that utilisation costs are incurred in two ways.[129] Firstly, as increased wear and tear which reduces unit efficiency, requiring additional fuel per unit of generation over time, and secondly, as the cost of movement enablement which, for thermal generators, requires generating extra steam pressure in addition to the steam pressure set point maintained to allow ramping to dispatch targets. This higher boiler pressure creates a continuous cost and reduction in efficiency arising from burning fuel to create high pressure steam and then throttling it across a control valve without extracting any valuable energy from it.

Enel X noted that high utilisation costs were the primary motivation for the Carboneras coal-fired plant in Spain to install a 20MW battery facility on site in response to a mandatory requirement to provide PFR.[130] In this case, the battery system is used to provide the frequency response, allowing the main plant to run more efficiently and avoiding wear and tear.

Stanwell also suggested that the burden on batteries from a mandatory approach would also be significant due to the expected increase in cycling which would reduce the operating life.[131]

Infigen explores the impacts on batteries in its submission and suggests that a mandatory approach will represent a material adverse impact that prevents batteries from delivering other more valuable services.[132]

Infigen suggested that there are two principal ways in which a mandatory approach would reduce the investment case for batteries:[133]

- cycling the battery through its warranty without providing any compensation for the cost of degradation[134]

129 Stanwell, Submission on the consultation paper, p.6.

130 Enel X, Submission on the consultation paper, p.5.

131 Stanwell, Submission on the consultation paper, p.4.

132 Infigen, Submission on the consultation paper, p.3.

133 Infigen, Submission on the consultation paper, pp.3-6.

134 Analysis undertaken by Infigen suggests that, under an assumed frequency distribution similar to that observed in 2005, a one-hour battery delivering contingency FCAS would cycle around 63 times in a year just responding to PFR, thereby reducing the warranty of the battery by up to 17% over the lifetime of the battery. For a 15-minute battery, this would extend to 254 cycles in a year, using 70% of the warranty. Infigen, Submission on the consultation paper, p.5.

- increasing the cost of delivering contingency services from a battery and increasing uncertainty in the future market value of contingency services.

Infigen suggested that a battery enabled to provide PFR will respond to all frequency disturbances outside of the narrow deadband.[135] Even when the battery is not operating for energy or regulation dispatch (ie power output is at 0MW) it will still react to frequency changes and provide PFR. The identified difference between a battery and traditional thermal generation is that a battery can be 'always available' to the market even if not enabled for energy or FCAS.

Infigen noted that a mandatory approach would create an incentive for batteries to make themselves unavailable to the market when not operating, thereby reducing system resilience and capacity reserves for PFR.[136]

#### Market impacts

An expected impact on FCAS markets was also noted in a number of stakeholder submissions.[137] The Australian Energy Council suggested that a mandatory requirement for generators to respond will mean that the marginal cost of being enabled for the provision of FCAS falls to zero, which in turn will distort traders' composition of their offers in the contingency FCAS markets. AGL suggested that generator will look to the energy market to recover the revenue lost in the FCAS market, which will see higher prices for consumers.

### A.3.3 Requirement to maintain headroom

Delta Electricity considered that a mandatory obligation on all generators to provide primary frequency response, without either a requirement or being paid to maintain headroom, would potentially reduce the overall headroom that is being provided by NEM participants when not enabled in the contingency FCAS markets.[138] This potential reduction in headroom represents a risk that a greater system security condition will arise. Delta Electricity considered it likely that the requirement for headroom will need to be revisited following the implementation of the proposed mandatory approach, and that it would be preferable for this to be undertaken through the rules framework.[139]

Stanwell suggested that the assumption under a mandatory approach that generators would have natural headroom available would overly burden some generators as semi-scheduled technologies will only provide a raise response if pre-curtailed.[140] Furthermore, if no natural headroom is available, the only generators that would respond would be contingency FCAS providers. These concerns were shared by the Australian Energy Council who suggested that a reliance on opportunistically stored energy may lead to a reduced, rather than greater, level of confidence in the power system.[141]

135 Infigen, Submission on the consultation paper, p.3.

136 Infigen, Submission on the consultation paper, p.2.

137 Submissions on the consultation paper: Australia Energy Council, pp.7-8, AGL, p.4; Stanwell, p.4.

138 Delta Electricity, Submission on the consultation paper, p.5.

139 Delta Electricity, Submission on the consultation paper, p.14.

140 Stanwell, Submission on the consultation paper, pp.4-5.

141 Australian Energy Council, Submission on the consultation paper, p.6.

Stakeholder submissions also suggested that if a mandatory requirement is implemented, then the requirement not to maintain stored energy or headroom to comply with this requirement be set out in the NER to provided certainty for market participants in relation to this key variable.[142] Stanwell considered that the costs associated with maintaining headroom are substantial and that any future considerations in respect should go through an AEMC-led consultation process.[143] The Clean Energy Council considered that clarity is particularly important for solar generators who need to ensure this exclusion would protect their right to generate at full capacity and as such only provide lower services in this instance.[144]

### A.3.4 Deadband setting

There are a range of views as to the appropriate frequency response dead band for a mandatory PFR requirement, with frequency response deadbands ranging from ±0.015Hz as proposed by AEMO through to ±0.5Hz as supported by a number of generators.[145]

The Commission noted that a number of generators are supportive of a mandatory requirement that only applies outside of a wider frequency response band such as ±0.5Hz.[146] This support was based on the understanding that the commercial impacts of providing sporadic frequency response to contingency events are relatively small (without the need to reserve headroom and incur the related opportunity costs). These generators have also indicated an acceptance that generator response following large contingency events provides a common benefit by maintaining system integrity. Delta Electricity considered that a wider deadband of control mandated on all participants would provide a safety net when unexpected conditions arise.[147]

The Australian Energy Council suggested that a more appropriate means of increasing the resilience of the power system is likely to be a combination of more robust FCAS Contingency Services specification and procurement, supported by a backstop governor requirement with a very wide deadband at ±0.5Hz.[148]

However, there was considerably more debate in relation to the proposed requirement for all generators to provide PFR outside of a narrow frequency response deadband close to 50Hz and inside of the NOFB. Many generators indicated that this proposal will result in material additional operating costs on an ongoing basis. Energy Australia suggested that more work should be done to determine whether ± 0.015Hz is a sensible deadband before implementing a mandatory approach, noting that this narrow deadband is unprecedented in Australia.[149]

ERM Power and Delta Electricity both suggested if a greater degree of frequency response is required then the Reliability Panel, in consultation with stakeholders, should determine the

142 Submissions on the consultation paper: Delta Electricity, p.14; Stanwell, p.6; Australian Energy Council, p.7.

143 Stanwell, Submission on the consultation paper, p.6.

144 Clean Energy Council, Submission on the consultation paper, p.4.

145 Submissions to the consultation paper: Australian Energy Council, p.7; CS energy, p.5; ERM Power, p.2.

146 Submissions to the consultation paper: Australian Energy Council, p.3; CS Energy, p.5; ERM Power, p.7; Delta Electricity, p.7; Infigen, p.2.

147 Delta Electricity, Submission on the consultation paper, p.7.

148 Australian Energy Council, Submission on the consultation paper, p.3.

149 Energy Australia, Submission on the consultation paper, p.5.

adequate quality of frequency control in the NEM and be responsible for amending the FOS as required.[150]

The AER considered that the determination of specifications set out in the PFRR may be better suited to the Reliability Panel given its role in determining the standards required to deliver a secure power system.[151]

### A.3.5 Compliance

The AER suggested that some challenges may arise in implementing and monitoring a mandatory obligation on generators and that this could lead to additional upfront and ongoing costs.[152] The AER is concerned that a requirement for generator to comply with the conditions of the PFRR would mean that the PFR characteristics of each generator would need to be recorded in order to assess compliance and that this may require the installation of high speed monitoring equipment for verification purposes, and associated protocols for data retention.

### A.3.6 Sunset provision

In response to the consultation paper a number of stakeholders suggested that if the Commission were to introduce a mandatory PFR requirement in the NER, it should be time limited or include a sunset clause as an assurance that it would be a temporary arrangement, and that there would be consideration of arrangements to incentivise parties in the longer-term.[153] Namely:

- The AEC recommended a three-year sunset period
- Alinta and Energy Australia recommended a two-year sunset period
- Enel X considered any interim solution for PFR be time-limited but did not specify a time period.

## A.4 Stakeholders' views on the draft determination

### A.4.1 A mandatory approach versus an incentive-based or market-based approach

While stakeholders generally agreed that regulatory change was required to improve frequency performance in the national electricity system, stakeholder submissions on the draft rule expressed a range of views in relation to the appropriateness of a mandatory requirement for narrow band PFR.

**Support for the draft rule**

Support for the draft rule was expressed by AEMO, Hydro Tasmania, TasNetworks and ENA.[154]

**Qualified support for the draft rule as an interim approach**

150 Submissions on the consultation paper: ERM Power, p.9; Delta Electricity, p.6.

151 Australian Energy Regulator, Submission on the consultation paper, p.3.

152 Australian Energy Regulator, Submission on the consultation paper, p.2.

153 Submissions to the Consultation paper: AEC, p.3, Alinta, p.2, Energy Australia, p.9, Enel X p.8.

154 Submissions to the draft determination: AEMO, p.1.; ENA, p.1.; Hydro Tasmania, p.1.; TasNetworks, p.1.

A number of stakeholders made it clear that they did not support the mandatory approach to the provision of PFR. However, when considered as a package, they expressed qualified support for the draft rule, including the three-year sunset and the Commission's commitment to continue to work on the development on further reforms to adequately remunerate providers of PFR.[155]

The AEC expressed this view as follows:[156]

> The AEC is seriously concerned about the non-market direction for frequency provision in this rule change, and is disappointed that it is to be made largely as proposed. It however accepts the circumstances behind the decision. The AEC is very pleased that the AEMC has articulated in the draft determination similar concerns, and has applied a three-year sunset and a work plan to an economically sustainable long-term solution.

### Do not support the draft rule

A number of generators and representatives of new energy technology businesses did not support the mandatory PFR arrangements set out in the draft rule. [157] These stakeholders expressed the view that the draft determination provides insufficient evidence to justify the Mandatory PFR arrangement, that it may be ineffective in delivering improved power system security and that it will lead to inefficient market and investment outcomes.

### Specification of the *primary frequency control band*

The draft determination accepted AEMO's view that universal narrow band PFR is urgently required to support system security and that the ongoing costs of PFR that is universally provided are likely to be relatively small for each individual generator due to the broad application.[158] However, a number of stakeholders argued that for some generators, the ongoing costs associated with the draft rule may be significant and the draft determination does not adequately consider these costs.[159] Consequently, these stakeholders recommended the Commission undertake more detailed analysis to support the determination of the Mandatory PFR rule and future frequency control reforms.

### Impacts on FCAS markets

A number of stakeholders expressed concern that the mandatory provision of PFR would suppress turnover of funds through the FCAS markets and reduce the economic incentives for generators to invest in new plant and business models to provide frequency response.[160] These concerns were noted by Tesla in its submission:[161]

155 Submissions on the draft determination: AEC, p.5.; AGL, p.1.; Alinta, p.1.; CEC,p.1.; CleanCo, p.1.; Delta, p.1.; Goldwind, p.1.; Origin, p.1.; South Australian Government, p.1.

156 AEC, Submissions on the draft determination, p.5.

157 Submissions on the draft determination: Energy Efficiency Council, p.1.; Enel X, p.1.; ERM Power, p.1.; Fluence, p.1.; Infigen, p.1.; Meridian Energy/Powershop, p.1.; Stanwell, p.1.; Snowy Hydro, p.1.; Tesla. p.1.

158 AEMO, Mandatory Primary Frequency Response - Electricity rule change proposal, 16 August 2019, pp.55-56.

159 Submissions to the draft determination: AGL, p.2.; CleanCo, p.2.; Meridian Powershop, p.4.; Snowy Hydro, p.2.

160 Submissions on the draft determination: CS Energy, p.5.; EEC, p1.; Enel X, pp.2,4,5,8.; ERM Power, p.3. Fluence, p.2.; Meridian Powershop, p.4.; Origin, p.4. Tesla, pp.1-6.

161 Tesla, Submission to the draft determination, p.1.

> Tesla is concerned that the near-term approach of mandating PFR will erode the value of existing frequency control ancillary services (FCAS) markets and dull investment signals for developers looking to invest in new technologies like utility scale storage or virtual power plants (VPPs).

Similarly Meridian Powershop noted:[162]

> We also expect that the regulation Frequency Control Ancillary Services (FCAS) markets, particularly the raise FCAS market will be significantly impacted by the introduction of the proposed rule change and that this will have a material impact on the commerciality of both existing and proposed generators, particularly BESS.

### A.4.2 Specification of the *primary frequency control band*

Stakeholder submissions to the draft determination and rule generally agreed with the proposal to set a *primary frequency control band* in the NER and for this band to be subject to review by the Reliability Panel. [163]

Hydro Tasmania and TasNetworks supported the proposed setting of ±0.015 Hz for the *primary frequency control band* as proposed by AEMO in its rule change request.[164]

However, a number of stakeholders considered that AEMO's rule change request provided insufficient evidence to support the proposed governor deadband of ±0.015Hz.[165] Stakeholders also expressed concern that an operational deadband of ±0.015 Hz is unprecedented in the NEM and may have unforeseen detrimental system and plant impacts.[166]

The AEC noted that it:[167]

> remains concerned that moving in one step to ±0.015 Hz is risky and inappropriate. It feels that a value consistent with Australian experience is a safer first step.

The AEC and ERM Power suggested that the *primary frequency control band* be initially set at ±0.050 Hz.[168] This was the setting at which the National Electricity Code, which preceded the NER, specified provision for mandatory PFR in the NEM regions prior to 2003.[169] The AEC

162 Meridian Powershop, Submission on the draft determination, p.4.

163 Stakeholder submissions to the draft determination: AEC, p.2.; AGL, p.2.; CS Energy,p.6.; Enel X, p.10.; ERM Power, p.3.; Hydro Tasmania, p.2.; Infigen, p.3.; TasNetworks, p.1.; Origin, p.4.

164 Submissions on the draft determination: TasNetworks, p.1.; Hydro Tasmania, p.2.

165 Submissions to the draft determination: AEC, pp.1-2.; CEC, p.2.; Infigen, p.3.

166 Submissions to the draft determination: AEC, pp.1-2.; Alinta, p.2.; Clean Co, p.2.; ERM Power, p.4.; Infigen, p.3.; Snowy Hydro, p.2.

167 AEC, Submission to the draft determination, p.2.

168 Submissions to the draft determination: AEC, p.2.; ERM Power, p.3.

suggested that the Reliability Panel could review this setting at a later date and vary it if necessary.

Snowy Hydro reiterated the view put forward by a number of generators in response to the consultation paper, that it is more appropriate for a mandatory frequency response band to be set at a wider range of ±0.50 Hz, to provide response to non-credible contingency events.[170]

### A.4.3 Arrangements for generators not dispatched to generate energy

A number of stakeholder submissions on the draft determination expressed support for the approach in the draft rule that would not require generators to comply with the PFRR if they are not dispatched for energy. These stakeholders recognised the intent of the draft rule not to adversely discriminate against battery energy storage systems.[171]

The AEC and Stanwell Energy did not support the approach in the draft rule that effectively pre-exempts battery energy storage systems from complying with the PFRR when they are dispatched at zero MW. [172] The AEC considered this element of the draft rule to be inconsistent, noting that:[173]

> A desire for non-discrimination on this sole aspect is puzzling within a proposal that is fundamentally discriminatory

While AEMO supported the intent of the draft rule, not to require battery energy storage to comply with the PFRR when dispatched for zero MW, it did not support the generalised drafting in the draft rule. AEMO highlighted that cl 4.4.2(c1) could indicate that Generators must only comply with the mandatory PFRR if they receive a dispatch instruction of more than zero MW in the energy market. Consequently, AEMO expressed concern at the implication that generators may change their control system settings or disable frequency response mode when not dispatched for energy, even though this is prohibited elsewhere in the NER:[174]

> Conceptually, a requirement that generating systems need only operate in accordance with the PFRR if they have received a dispatch instruction of more than zero MW implies that Generators can change their control system settings or disable frequency response mode when not dispatched for energy. This would inherently conflict with other NER requirements (clauses 4.9.4(e) and S5.2.2) for Generators to seek Network Service Provider (NSP) and AEMO's approval prior to any changes.

169 NECA, Technical standards code changes gazetted 27 March 2003. S5.2.6.4 deleted and replaced with S5.2.5.11.

170 Snowy Hydro, Submission to the draft determination, p.3.

171 Submissions to the draft determination:CEC, p.5.;Enel X, p.11.Origin, p.5.;South Australian Government, p.2.

172 Submissions to the draft determination: AEC, p.3.; Stanwell, p.5.

173 AEC, Submission to the draft determination, p.5.

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

AEMO proposed that the final rule include a specific derogation for battery energy storage systems rather than the general approach taken in the draft rule.[175]

### A.4.4 No requirement to maintain headroom

A number of stakeholders supported the clarification in the draft rule that the PFRR must not require generators to maintain headroom or additional stored energy.[176] Stakeholders noted that any mandatory headroom requirement would be very costly to both generators and the market as it would reserve a portion of generation capacity that could otherwise be available to supply energy to customers through the energy market.

However, some stakeholders highlighted that the exclusion of headroom from the Mandatory PFR arrangement may lead to a portion of the reserve capacity procured through the contingency FCAS markets being utilised for normal frequency management. Under this scenario, there may be a reduction in the availability of contracted contingency reserves when they are required to restore system frequency following a contingency event. [177]

For example, Origin stated:[178]

> The draft rule makes clear that generators do not need to maintain headroom to meet their PFR obligations. We support this decision, as a mandatory obligation to retain headroom would result in each generator having to store energy, and inefficient costs being absorbed by all participants. However, generators that supply contingency FCAS must retain headroom to meet their FCAS obligations. The mandatory PFR framework is likely to rely on the headroom provided from generators providing FCAS to be effective.

Similarly, Infigen noted:[179]

> Infigen supports AEMC decision not to mandate headroom or stored energy. However, without a mechanism to procure headroom or stored energy, governor response alone may be ineffective at maintaining frequency.[sic]

### A.4.5 Interactions with the generator performance standards for frequency control

In their submissions to the draft determination, a number of stakeholders raised several concerns that making changes to their plant to comply with the PFRR could potentially require renegotiation of relevant components of their connection agreement and generator performance standards under clause 5.3.9 of the NER.[180]

175 Ibid.

176 Stakeholder submissions on the draft determination: AEC, p.2.; AGL, p.2.; CEC, p.2.; CS Energy, p.2.; Enel X, p.2.; Infigen, p.4.;ERM Power, p3.; Origin, p.4.; TasNetworks, p.1.

177 Submissions to the draft determination: AEC, p.3.; Enel X, pp.7-8.; Infigen, p.4.; Origin, P.4.; Stanwell, pp.4-5.

178 Origin, Submission to the draft determination, p.4.

179 Infigen, Submission to the draft determination, p.4.

180 Submissions to the draft determination: AGL, p.3; CEC, p.4; Goldwind, p.2; Meridian Powershop, p.3.

AGL stated that such changes could require the generator to provide updated generator models at considerable cost:[181]

> It is possible that for some generator system changes, AEMO will seek to apply NER processes such as those in clause 5.3.9 and S5.2.2 and this may result in generators being asked to conduct modelling. Modelling would significantly slow the implementation of the PFR and result in significant cost to generators, entirely counteracting the urgency driving this rule change forward. Accordingly, the final rule should establish that mandatory PFR implementation will not give rise to generator change processes under clause 5.3.9 and S5.2.2, nor will generators be required to undertake power system modelling.

In its submission to the draft determination, AEMO stated the final rule should include a provision to suspend the application of cl 5.3.9(d) for approved changes to plant to comply with the PFRR. AEMO noted that:[182]

> After having reviewed a substantial number of GPS applicable to the generating systems that will be affected by the proposed rule, AEMO considers that there is a need to expressly confirm that clause 5.3.9 of the NER does not apply to Generators where the only changes made to plant to meet the PFRR are, for example:
>
> - Distributed control systems (DCS) load controllers.
> - Deadbands and droop settings in governor control software.
> - Governor gains (Kp and Ki) and deadband software.

### A.4.6 Monitoring and verification of generator response

The AEC, Snowy Hydro, ERM Power, and Infigen raised concerns that, although the rule does not explicitly authorise it, AEMO may still require generators to install upgraded or high-speed metering equipment to verify compliance with the PFRR.[183]

ERM Power also identified that, while it is not the intention in the draft determination, the draft rule could allow AEMO to require Generators to modify high-speed metering and monitoring equipment to comply with the mandatory PFR:[184]

> Consistent with the Commission's [intention in the draft determination], there should be no ability to require the modification of existing monitoring equipment. However, it is not clear how draft rule 4.4.2A (b) (4) achieves the Commission's intent. The draft rule appears to leave open to AEMO to oblige such equipment through its Primary Frequency Response Requirements (PFRR). The final rule should specifically set out the exclusion of any such requirement being imposed on a generator.

181 AGL, Submission to the draft determination, p.3.

182 AEMO, Submission to the draft determination, p.10.

183 Submissions to the draft determination: Australian Energy Council, p.3.; ERM Power, p.5.; Infigen, p.4.; Snowy Hydro, p.5.

184 ERM Power, Submission to the draft determination, p.5.

These stakeholders requested that the final rule should clarify that the mandatory PFR requirement does not authorise AEMO to require any upgrades to generator metering equipment.

### A.4.7 Sunset provision

Stakeholder submissions on the draft determination generally expressed support for the proposed three-year sunset to the Mandatory PFR arrangements.[185] Stakeholders stated that the sunset provision is an important mechanism to demonstrate that the market bodies will continue to work on the development of alternative and complementary incentive arrangements for PFR.

As noted by the AEC:[186]

> the sunset has two critical benefits:
>
> - It sends a clear message that the AEMC shares these stakeholders' concerns and that it is only prepared to support the rule as a stop-gap measure to address an immediate security issue; and
> - It forces all parties to commit constructively to the work plan knowing that a better solution must be in place by 2023.

A number of stakeholders proposed that the Commission consider bringing forward the three-year sunset, subject to progress on the development of alternative PFR arrangements.[187]

Submissions from AEMO and networks proposed that the Commission consider extending the sunset duration or make any sunset to the Mandatory PFR arrangement contingent on the development and implementation of a future PFR arrangement. [188]

AEMO stated in its submission:[189]

> AEMO endorses the complementary nature of an incentive scheme that could act alongside a near-universal provision of PFR. Hence, consideration should be given to not requiring a sunset date for MPFR and instead replaced with consideration of whether the MPFR complements an incentive scheme.

## A.5 Commission's analysis

185 Submissions on the draft determination: AEC, pp.3-4.; Alinta, p.2.; CS Energy, p.2.; ERM Power, p.2.; AGL, p.1.; Infigen, p.2.;Origin, p.3.; SnowyHydro, p.2.

186 AEC, Submission on the draft determination, pp.3-4.

187 Submissions on the draft determination: Fluence, p.2.; Infigen, p.2.; CleanCo, p.4.; Enel X, p.10.; Hydro Tasmania, p.2.; Tesla, p.6.

188 Stakeholder submission on the draft determination: AEMO, ; ENA, ; TasNetworks, .

189 AEMO, submission on the draft determination, p.13.

## BOX 3: SUMMARY OF FINAL RULE

The Commission's final rule introduces a requirement in Chapter 4 of the NER that all registered scheduled and semi-scheduled generators who have received a dispatch instruction to generate at a volume above zero MW be required to comply with the PFRR.* AEMO has advised the AEMC that this reform will meet the immediate system need for effective frequency control in the NEM. AEMO's view is supported by technical advice received from AEMO's consultant, Dr John Undrill.

The final rule introduces a new *primary frequency control band* of ±0.015 Hz (or some other range as specified by the Reliability Panel in the power system security standards) outside of which scheduled and semi-scheduled generators must provide PFR. This would set a lower bound on the deadband to which individual generators must comply under the conditions of the PFRR. The Commission considers that the *primary frequency control band* is a key variable associated with the final rule, which has implications for both system operation and the operation of the markets for electricity and ancillary services in the NEM. In the absence of a clearly defined frequency performance standard in the FOS, the Commission has determined that the minimum bound for the *primary frequency control band* be specified in the NER, and not subject to full discretion by AEMO in the PFRR.

The Commission has also specified in the final rule that generators are not required to maintain additional stored energy as a condition of complying with the requirements of the PFRR. The Commission acknowledges that a requirement in the PFRR that generators maintain stored energy was not part of AEMO's proposed rule. However, the PFRR is subject to change, and any future obligation which results in a large cross-section of the generating fleet being required to maintain stored energy would likely impose substantial costs on generators that are likely to outweigh the additional benefits this might provide to the security of the power system. This aspect of the final rule will provide greater clarity and certainty to generators and will limit the likelihood of substantial unwarranted costs being incurred by generators in the future.

The final rule also provides that the PFRR must not require the installation or modification of monitoring equipment to monitor and record frequency for the purpose of verifying compliance with the mandatory PFR requirement. In response to stakeholder concerns made on the draft rule, the final rule includes new clause 4.4.2A(c)(2) which clarifies that the PFRR cannot require a Generator to install or upgrade monitoring equipment for this purpose.

Unlike other generation technologies, battery energy storage systems are capable of providing a frequency response when they are neither charging or discharging, i.e. neither supplying nor consuming energy from the grid. Under the final rule, generators that are not dispatched in the energy market to generate electricity are not required to operate in a frequency response mode in accordance with the PFRR. As such, the final rule includes a provision that generators are only required to provide PFR when they have received a dispatch instruction to generate at a volume greater than zero MW.

All other specifications of the technical criteria for providing primary frequency response would be determined by AEMO in consultation with market participants and set out in the PFRR. The final rule requires that the PFRR must include the following:

- a requirement that Scheduled Generators and Semi-Scheduled Generators set their generating systems to operate in frequency response mode within one or more primary frequency response performance parameters (which may be specific to different types of plant), which must include maximum allowable deadbands, and may include but not be limited to; droop; and response time;
- the conditions or criteria on which a generator may request and AEMO may approve a variation or exemption from any applicable performance parameters
- details of information to be provided to AEMO to verify compliance with the PFRR.

The final rule also provides that clause 5.3.9 (which sets out the requirements for generators proposing to alter a connected generating system) does not apply in relation to any modifications made to a generating system by a Scheduled Generator or Semi-Scheduled Generator in order to comply with the PFRR.

The Commission's final rule will result in most generators with a nameplate rating less than 30MW being not required to comply with the PFR requirement (unless they are registered as a scheduled or semi-scheduled generator). Generators will also only be required to provide PFR when dispatched above zero MW in the energy or ancillary services markets. In addition, AEMO may approve an exemption or variation to the requirement to provide PFR for specific generating plant which is technically incapable of complying with the requirements of the PFRR. This is aspect of the final rule is described further in appendix B.

The Commission considers that in the long term it would be better to incentivise generators to provide primary frequency response. Given the time associated with developing such arrangements it is not possible to do this in time to address the immediate system security needs. Further work also needs to be undertaken to understand the power system requirements for good frequency control. Therefore, the final rule includes a sunset to the mandatory primary frequency response requirement. This creates a clear signal that the Commission is committed to the development of an arrangement that appropriately incentivises primary frequency response provision to be put in place prior to the sunset.

In accordance with the sunset, the mandatory approach will be in place for a three-year period, expiring in June 2023. Prior to the sunset, the Commission intends to develop and implement an enduring arrangement through the assessment of the *Removal of disincentives to primary frequency response* rule change and any other related rule change requests received. The sunset provision also places a discipline on the industry and market bodies to focus on longer-term solutions that are sustainable in the longer-term.

**Changes between the draft and final rule**

The main changes in the final rule in relation to the mandatory requirement to provide PFR are:

- Cl 4.4.2A(b) has been amended in the final rule so that while the performance parameters specified in the PFRR must include maximum allowable deadbands, they may include (but are not limited to):
  - droop; and
  - response time.
- Cl 4.4.2A(c) includes a new provision that confirms that the PFRR must not require a Generator to install or modify monitoring equipment to monitor and record the provision of PFR to verify compliance with the mandatory PFR requirement set out in Cl 4.4.2(c1).
- The final rule also provides that clause 5.3.9 (which sets out the requirements for generators proposing to alter a connected generating system) does not apply in relation to any modifications made to a generating system by a Scheduled Generator or Semi-Scheduled Generator in order to comply with the PFRR.

*The Commission will also propose that this requirement be classified as a civil penalty provision under the National Electricity (South Australia) Regulations.

### A.5.1 A mandatory requirement for all scheduled and semi-scheduled generators

**A mandatory obligation to apply to scheduled and semi-scheduled generators**

The nature of a mandatory obligation is to require all scheduled and semi-scheduled generators to provide a primary frequency response in accordance with a pre-defined set of conditions. Since the nature of the obligation is mandatory, while there could be some variations in the requirements placed on different generators, it is inevitable that some generators would be better equipped than others when it comes to providing a primary frequency response.

The Commission considers this immediate change to the NER is justified by the need to improve and maintain the security and resilience of the national electricity system to meet AEMO's concerns. AEMO's views, which were informed by its consultant Dr. John Undrill, are that all of the generation fleet needs to provide primary frequency response in order to be effective in managing system security concerns. The key recommendation provided in Dr. Undrill's advice to AEMO is that:[190]

> 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.

Given the need for an immediate change to the NER to restore effective frequency control in the NEM, the Commission accepts AEMO’s proposal that primary frequency response should be required from all capable generating systems in the NEM with a capacity of more than 30

190 Dr. John Undrill, Notes on frequency control for the Australian Energy Market Operator, 5 August 2019, p.3.

MW. This approach will deliver broad-based provision of PFR and is expected to fulfil the objectives defined by AEMO in its rule change request.

The Commission recognises stakeholder concerns that a requirement for *all* generators to provide primary frequency response outside of a narrow frequency response deadband close to 50Hz could result in additional operating costs on an ongoing and upfront basis. Further, that these costs are likely to impact generators differently depending on their capability and technology. These ongoing costs could include direct utilisation costs of providing the response through increased wear and tear and resource consumption; as well as the opportunity costs of foregoing alternative revenue through the energy market.

Despite this, the Commission agrees with AEMO's view, informed by its consultant Dr. John Undrill, that a broad application of the mandatory approach would mean that costs incurred by each *individual* generator would be minimised. If every scheduled and semi-scheduled generator is required to provide primary frequency response then this will minimise the costs for each individual generator, since no one generator will bear the burden of responding - instead, this will be shared across the entire fleet. In other words, the costs associated with introducing the requirement on *all* generators are likely to be cheaper in total compared with the outcome where only some generators were required to provide primary frequency response.

In addition, given that all generators will be required to provide primary frequency response, similar costs will be imposed on each generator. Given that the wholesale market is competitive, this means that the generators will all be able to recover their costs through adjusting their energy market offers, and so in turn, wholesale energy market prices. Wholesale electricity prices will reflect the necessary cost of providing primary frequency response in order to manage system security. Obviously, it will be harder for generators with higher costs than the marginal generator, and those that are lower in the merit order to recover their costs through the energy market. However, the Commission considers that this is likely to be manageable.

This is supported by AEMO's case study of PFR in the Wholesale Energy Market (WEM) in Western Australia which provides evidence that a mandatory obligation applied to a broad cross-section of the generating fleet results in relatively small changes in the generation output associated with the provision of primary frequency response by each individual generator, discussed further below.

***WEM Primary Frequency Response Case Study***

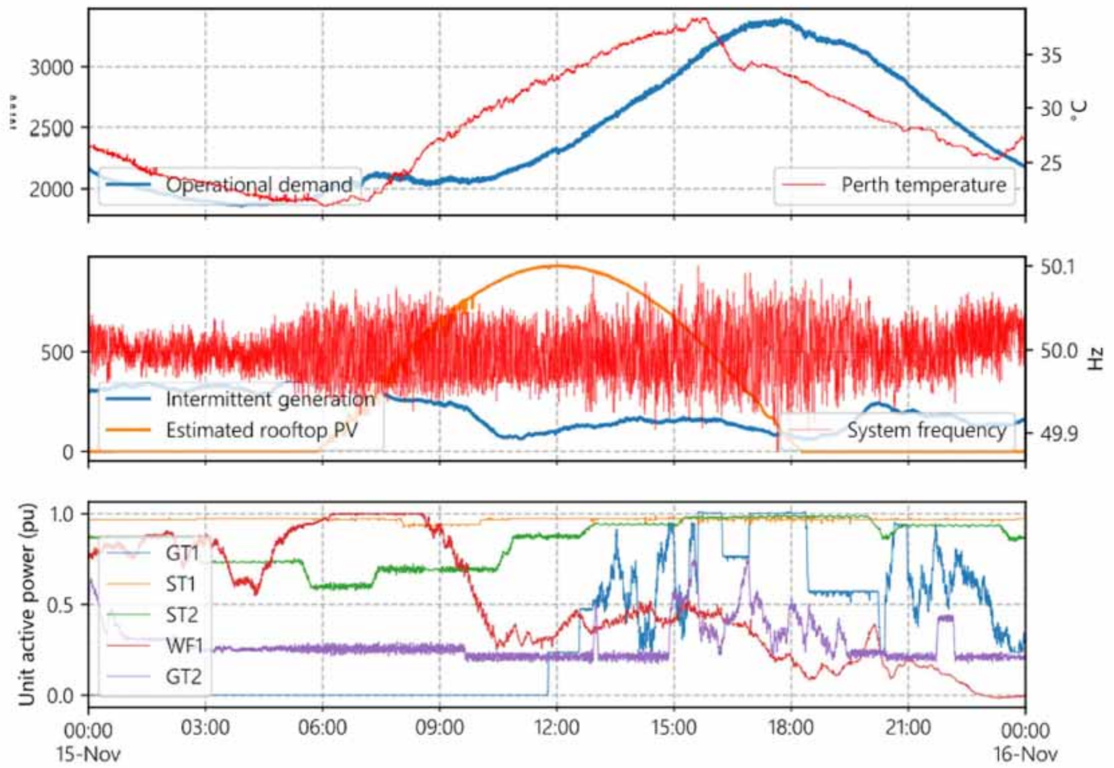
AEMO recently undertook a case study to look at the impacts of the mandatory requirements in the Wholesale Electricity Market (WEM) in Western Australia. The case study examined a one-week snapshot of various conditions and describes the standards and behaviour of generators supporting frequency control.

Figure A.1 is taken from a 24-hour period during the week and shows

- system operational demand and ambient temperature in Perth
- system frequency, total wind farm output and estimated total output from rooftop PV

- active power output of various anonymised units operating in accordance with the PFR requirements.

**Figure A.1: WEM system operation 15-16 November 2019**




Source: AEMO, WEM Primary Frequency Response Case Study

A key observation from the figure is that ST1 and ST2, which are both thermal coal units providing PFR, generally do not move far from their basepoints, with variation only a very small fraction of output (typically ~1%). Further information on AEMO's case study was contained in an attachment to the draft determination which is available on the AEMC project page.

The Commission notes that the final rule includes a framework for a generator to request and AEMO to grant an exemption or variation from the primary frequency response parameters set out in the *Primary frequency response requirements*. The Commission considers that the exemption framework allows for generators to avoid incurring unreasonably onerous costs associated with complying with the final rule. The exemption framework includes a set of principles to guide AEMO's assessment of request for exemptions. These principles include, among other things, consideration of upfront and ongoing costs associated with complying with the *Primary frequency response requirements.* The exemption framework is discussed further in Appendix B.

**Market impacts**

The Commission also expects that a mandatory primary frequency response requirement would drive increased participation in the contingency FCAS markets, which would put downward pressure on prices for these services in the short-term, lowering prices for consumers. The Commission notes that FCAS revenue is a dominant revenue stream for new sources of generation such as demand response providers, market ancillary service providers and battery energy storage systems. These new technologies are a critical source of FCAS capability as thermal generation plant retires.

Additionally, the Commission is aware of stakeholder concerns in relation to the potential for the mandatory PFR requirement to dampen the available incentives for providing frequency control through the markets for FCAS. While AEMO has indicated that it does not intend to reduce the quantity of contingency reserve services that it procures as a consequence of this rule, it is expected that the mandatory PFR requirement will drive increased participation in the FCAS markets, which will increase competition and put downward pressure on prices for these services. The Commission recognises that the evolution of the FCAS markets has not kept pace with the system requirements for frequency control and that the implementation of mandatory PFR is now required to support the secure operation of the power system. The Commission considers that further work needs to be done to understand the power system requirements for maintaining good frequency control and to reform the existing frequency control frameworks to meet these needs now and in the future.

In making this final determination, the Commission has undertaken a preliminary analysis of recent developments in the FCAS markets. This analysis is included for reference in appendix g.

The Commission considers this change to the NER is justified by the need to improve and maintain the security and resilience of the national electricity system to meet AEMO's concerns, but also recognises that the final rule will not adequately value or reward frequency response from capable generating units.  For example, passing the cost of primary frequency response through the energy market does not reveal the extent of these costs to the market and places the costs directly on consumers rather than recovering the costs through the FCAS markets. Generators are therefore not exposed to the full costs of managing system frequency through causer pays and thereby have little incentive to minimise any adverse impacts on frequency.

Therefore, the Commission considers that in the long-term there would be benefits in developing arrangements under the NER to incentivise market participants to provide primary frequency response. This requires more thought and development and so could not be put in place to address the immediate concerns raised in AEMO's rule change request.

As discussed in chapter 3, further refinements to the NER in relation to valuation and remuneration of frequency response will be considered through the assessment of AEMO’s *Removal of disincentives to the provision of PFR* rule change request and other related rule change requests received.

#### Sunset provision

Given that further work needs to be done to assess the power system needs for frequency control and the costs and benefits of further reforms to the frequency control arrangements, the final rule includes a sunset to the mandatory obligation on generators to provide primary frequency response. In accordance with the sunset, the mandatory approach will be in place for a three-year period, expiring in June 2023.

The Commission's final rule includes Schedule 2 which removes the mandatory primary frequency response framework from the rules as at 4 June 2023. The relevant rules will then revert to the version of those rules in existence at the time this rule is made.

The Commission has considered stakeholder feedback on the draft determination including the range of views:

- support for the inclusion of the sunset provision for the Mandatory PFR arrangement
- that the sunset provisions be brought forward if possible
- that the sunset provision be extended, removed or made contingent on the development of a future incentive arrangement for PFR

The final rule retains the provisions included in the draft rule that will repeal the mandatory PFR arrangement on 4 June 2023, three years after the commencement date. The Commission considers that three years is sufficient time for the development of an alternative or complimentary arrangement that appropriately incentivises the provision of primary frequency response and support good frequency control. These further reforms will be progressed through the assessment of the *Removal of disincentives to primary frequency response* rule change as well as any other relevant rule change requests received. The three-year sunset provides a clear signal that the Commission is committed to undertaking the necessary work to develop solutions for PFR that are sustainable in the longer-term.

#### Moving to a framework that incentivises primary frequency response

As part of the development of arrangements that incentivise primary frequency response, the Commission will be seeking to undertake an investigation into the power system requirements for maintaining good frequency performance. The Commission is aware that there is some analysis that indicates that effective frequency performance during normal operation could be achieved with significantly less than the entire fleet being responsive to small frequency deviations during normal operation.

On 18 September 2019, AEMO published an updated report by DIGsilent which presented analysis and commentary on the further deterioration of frequency performance in the NEM since its earlier report in 2017. The DIGsilent report includes a summary of recent international developments in relation to frequency control and provides a number of recommendations to improve frequency control in the NEM. The updated DIGsilent report noted that international experience demonstrates that:[191]

> "A relatively small amount of primary frequency response can make a significant

191 DIGsilent, Frequency in the Normal Operating Frequency Band - Update report for AEMO, 18 September 2019, p.31.

> difference to the regulation of frequency"
>
> and
>
> "There is a cost to the market from requiring high efficiency plant to provide frequency control at the expense of energy"

However, the Commission also notes the system operator's position and view that it is not appropriate to define a minimum level of responsive generation to meet the policy objectives in its mandatory primary frequency response rule change request. AEMO's submission noted that:[192]

> "A limited, or 'minimum level' provision of PFR from only a sub-set of capable generation focuses on improving a narrower distribution of frequency under normal operating conditions, but would not, by itself, achieve the other objectives. A widespread obligation:
>
> - diminishes the operational burden on any individual generator to the lowest practicable level and in an equitable as possible manner, thus reducing the longer term operating impacts for all generating systems;
> - ensures broad-based contribution to the public good of stable and resilient control of power system frequency; and
> - provides greater resilience and facilitates adequate control where a need for PFR arises, particularly where this need may initially be unforeseen.
>
> Compartmentalising the individual power system objectives and trying to manage them in isolation to a minimum level is unlikely to be successful."

Given these differing views, the Commission therefore considers that further work needs to be done to understand the power system requirements for maintaining good frequency control and the associated costs and benefits of alternative frequency control arrangements which could build on work being undertaken by AEMO through the *Renewable Integration Study*.[193] This analysis should be undertaken through the assessment of AEMO's *Removal of disincentives to the provision of primary frequency response* rule change request.[194] This rule change request will consider further amendments to the NER in relation to the valuation and remuneration of frequency response and include an assessment of what proportion of the fleet should provide PFR. It may be useful to think about this under the following conditions:

- *Following contingency events* — All capable generation plant should help support system security subject to plant safety limits and energy availability. From a system control perspective, it is not appropriate for latent generation capacity to exist in the power

192 AEMO, Submission to the consultation paper, p.3-4.

193 AEMO, 2019, *Maintaining Power System Security with High Penetrations of Wind and Solar Generation: International insights for Australia*, published October 2019. Accessed at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/future-grid/renewable-integration-study

194 This rule change request raises the issue of "poor frequency performance during normal operating conditions" and proposes changes to the NER to improve the incentives for generators providing PFR on a voluntary basis to assist in the control of frequency during normal operation.

system at the same time as emergency frequency control schemes are operating to rebalance system supply and demand. The operation of emergency frequency control schemes is less predictable in a changing power system and successful operation can depend on the prevailing system conditions. Such emergency frequency control schemes include automatic under frequency load shedding or over-frequency generation shedding.

- *During normal operation* — It may be appropriate for a smaller proportion of the generation fleet to be actively involved in providing frequency response on a continuous basis. Such an approach allows for plant that is best suited to providing ongoing active power modulation to provide frequency control during normal operation, while other plant that is more suited to providing a steady power output can focus on the production of megawatts while being unresponsive to frequency variations within the NOFB.

The Commission considers that ideally an approach incorporating a mandatory contingency response requirement along with an incentive or marked-based provision of continuous primary regulating response would be implemented. However, given the immediate system security needs, and the advice from AEMO that the whole of the fleet should provide primary frequency response, the Commission proposes to undertake this work through AEMO's second rule change request and other related rule change requests received. The development of an effective mechanism to value and reward provision of PFR is part of the future reform pathway set out in chapter 3.

#### Conditions of the mandatory obligation to be set out in the PFRR

The Commission's final rule introduces a new clause 4.4.2(c1) of the NER to require that all registered scheduled and semi-scheduled generators, that have received a dispatch instruction for a volume greater than zero MW, must operate their generating systems in accordance with the PFRR as applicable to that plant. AEMO may approve an exemption or variation to the requirement for specific generation plant which is technically incapable of complying with the requirements of the PFRR, or where compliance would be unreasonably onerous having regard to ongoing and upfront costs relative to the revenue earned by the relevant generating unit in the NEM during the 12 months prior to the date of the application for exemption or variation, as applicable. This aspect of the final rule is described further in Appendix C.

The Commission considers that AEMO's proposal of implementing the PFR requirement through Chapter 4 of the NER is more likely to achieve the desired result than implementation through Chapter 5 of the NER, as suggested by Dr. Sokolowski. Implementing the requirement through S5.2.5.11 would require provision of primary frequency response from only new connecting generators, which would be unlikely to achieve the frequency performance objectives as put forward by AEMO which are aimed at capturing the entire fleet.

The Commission's final rule will result in generators with a rated capacity less than 30 MW not being required to provide PFR unless they have registered as a scheduled or semi-scheduled generator.[195]

Under the final rule, AEMO is responsible for developing and maintaining the PFRR in consultation with stakeholders, and for publishing the PFRR on its website.

AEMO submitted to the Commission an initial draft of the PFRR for consideration together with the rule change requests, and provided an updated version in October 2019. This can be found on our website.[196]AEMO will take into account stakeholder feedback provided through the rule change process in refining this, before finalising the document. The finalised document will form the initial interim PFRR, which AEMO must publish by 4 June 2020. Following this, AEMO is required to develop and publish on its website the first PFRR under the new rules by 6 December 2021.

A further description of the interim PFRR, and the process for making changes to the initial PFRR in consultation with stakeholders, is set out in Appendix C.

***Performance parameters for PFR***

The final rule requires AEMO to specify the performance parameters for PFR in the *Primary frequency response requirements* document. As in AEMO's proposed rule, Cl 4.4.2A(b) of the draft rule set out that the performance parameters must include but are not limited to:

i. maximum allowable deadbands, which must not be narrower than the primary frequency control band outside of which Scheduled Generators and Semi-Scheduled Generators must provide primary frequency response;

ii. droop; and

iii. response time

The drafting of Cl 4.4.2A(b) in the draft rule was consistent with the proposed rule drafting provided by AEMO in its rule change request.

On 27 February 2020, the AEMC facilitated a technical working group to discuss stakeholder feedback to the draft rule and the policy directions for the final rule. During these stakeholder discussions, it came to light that while a generator may operate its plant in a frequency response mode, the specific response characteristics depend on the availability of stored energy in the energy system. Therefore, in the absence of available stored energy it may be difficult for a Generator to commit to a frequency response that meets a specific droop or response time and to verify compliance against such performance parameters. In particular, thermal plant that do not hold stored energy would not typically be able to comply with a

195 The Commission notes it has a pending rule change request from the Australian Energy Council that seeks to lower the threshold for generators to be scheduled to 30 MW.

196 The draft PFRR will need to be updated by AEMO to take into account the final rule.

requirement to increase generator output by 5% over a period of 10 seconds as is set out in AEMO's draft PFRR.[197]

The Commission notes that the particular settings for the PFR performance parameters (primary frequency response parameters) are a matter for AEMO to determine, through consultation on the PFRR. The exemption framework provides a process through which generators and AEMO can negotiate individual exemptions or variations from the performance parameters specified in the PFRR. AEMO's draft PFRR also includes a list of criteria that AEMO recognised may justify the limitation of an active power response in response to a change in frequency, these criteria recognise that it may be necessary to limit a generating systems response to:[198]

- maintain operation between the Affectedgenerating system's Maximum Operating Level and Minimum Operating Level
- avoid rough running ranges associated with the affected generating system
- maintain operation within environmental operating licence conditions
- manage safety or stability of the affected generating system
- respond to primary energy availability.

However, given that there may be circumstances where it may be difficult to verify performance against certain PFR performance parameters, the Commission has revised the final rule to provide AEMO with adequate guidance on the *primary frequency response parameters* to be included in the PFRR, while at the same time giving AEMO increased flexibility as to how it specifies these parameters. The final rule therefore amends cl4.4.2A(b) such that the PFRR include one or more performance parameters which:

i. must include maximum allowable deadbands which must not be narrower than the *primary frequency control band* outside of which *Scheduled Generators* and *Semi-Scheduled Generators* must provide *primary frequency response*; and

ii. may include (but are not limited to):

A droop; and

B response time,

Collectively these parameters are the *primary frequency response parameters*.

***Monitoring and verification of Generator response***

The Commission notes the AER's concerns in relation to monitoring individual generator's compliance with the conditions of the PFRR. The Commission considers that initial testing and verification of compliance with the PFRR would be important. However, ongoing periodic assessment would likely be sufficient and that the installation of high-speed monitoring equipment in order to continuously assess compliance would likely be unnecessary.

197 AEMO, draft Primary frequency response requirements, August 2019, p.7.

198 ibid.

In order to enable the initial and periodic assessment of compliance, the Commission has introduced a new clause 4.4.2A(4) under the final rule to require that the PFRR include details of the information to be provided by generators to verify compliance with the PFRR and any compliance audits or tests to be conducted. This is consistent with AEMO's proposed rule.

Under the NER, providers of market ancillary services are required to install and maintain approved monitoring equipment to verify their compliance with the Market ancillary service specification (MASS).[199]

However, the Commission notes that not all generators provide market ancillary services, and so requiring all generators to install monitoring equipment to verify compliance with the PFRR would increase the overall costs associated with the final rule. While AEMO did not propose such additional monitoring requirements in its rule change request, it did provide a commentary on how the expectations for generator performance under the proposed PFRR compare with that of FCAS providers under the MASS. [200]

> The PFRR does not specify a sustain time for the delivery of PFR. In this respect, the PFRR differs from the MASS, which requires that generating systems delivering PFR in the form of Contingency FCAS must be capable of delivering PFR consistent with its plant's FCAS market enablement, which will include an ability to sustain a response over a period appropriate for that Contingency FCAS
>
> [...]
>
> AEMO acknowledges that there are many reasons why plant might not be capable of sustaining its response, such as primary energy or environmental limits, or physical limits related to plant capability or safety, such as operating temperature limits, rough running zones, or pressure limits. A Generator would not be in breach of these requirements if it was unable to sustain PFR for such reasons.

AEMO explained that the intention of its proposed rule is for all capable generators to operate in a frequency response mode and for the generation control systems to be configured such that a generator's PFR is not counteracted by secondary control systems of plant load controllers.[201]

The Commission has made a final rule that provides that the PFRR must not require the installation or modification of monitoring equipment to monitor and record the response of the relevant generating system to changes in frequency for the purpose of verifying compliance with the mandatory PFR requirement. The final rule does require AEMO to document the details of the information to be provided by Generators to verify compliance with the PFRR, including any compliance tests or audits for the purpose of verifying compliance through its PFRR.

199 NER Clause 3.11.2(f)

200 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp.52-53.

201 Ibid.

Consistent with AEMO's proposed rule, the final rule also introduces a new clause 4.4.2A(d) to require that AEMO publish on its website, and update as necessary, a register of generators who have been granted an exemption or variation from complying with some or all of the parameters set out in the PFRR. Further discussion of the exemption framework is set out in Appendix B.

**No requirement to provide PFR unless dispatched to generate energy**

Clause 4.4.2(c1) of the final rule states that each Scheduled Generator and Semi-Scheduled Generator that has received a dispatch instruction to generate at a volume greater than 0 MW must operate its generating system in accordance with the Primary Frequency Response Requirements as applicable to that generating system.

The Commission acknowledges concerns raised by providers of battery energy storage systems that batteries would likely be disproportionately burdened by a mandatory approach since they are always available to the market, even when not enabled for energy or FCAS. Clause 4.4.2(c1) of the final rule requires that generators only operate their generating systems in accordance with the PFRR when they have received a dispatch instruction to generate at a volume greater than zero MW.

The Commission has considered AEMO's concern that the drafting of clause 4.4.2(c1) may conflict with the other parts of the NER, including the requirement for a generator to seek NSP and AEMO approval before changing their frequency response mode or making changes to control system settings.[202]

The Commission considers that clause 4.4.2(c1) of the final rule is consistent with the existing requirement in the NER for generators to seek NSP and AEMO approval prior to making changes to the frequency response mode or settings associated with their plant. Under the NER a generator may notify and seek NSP and AEMO approval for the approved frequency response settings for its generator that at all times comply with the requirements under the generator access standards set out in S5.2.5.11. These requirements include that the generating system be capable of operating in a frequency response mode with certain settings including deadband and droop.

Under the final rule, a battery energy storage system could be operated at all times in a frequency responsive mode but have different pre-approved control system settings that applied depending on whether it is charging, discharging or at rest. As shown in the following table, when the system is dispatched for a value greater than zero MW, the applicable control settings would need to comply with AEMO’s PFRR, whereas at other times the PFRR would not apply.[203]

202 NER cl 4.9.4(e) and cl S5.2.2)

203 The Commission notes that a generators ability to comply with the PFRR may be limited by the physical characteristics of the generating system that affect its ability to operate in a frequency response mode. These limitations are recognised in the exemption principles included in the final rule, cl. 4.4.2B(a)(1)(v). AEMO's draft *Primary frequency response requirements* recognises that a generators ability to be responsive to frequency may be limited by, among other things, physical limits related to plant capability or safety, such as operating temperature limits,rough running zones, or pressure limits.

Table A.1: **Application of the Mandatory PFR requirement to battery energy storage systems**

| DISPATCH STATUS | OBLIGATION TO COMPLY WITH PFRR UNDER CL 4.4.2(C1) |
|---|---|
| Charging — dispatch < zero MW | no |
| At rest — dispatch = zero MW | no |
| Discharging — dispatch > zero MW | yes |

Source: AEMC

The final rule applies an obligation on a scheduled and semi scheduled generator in relation to how it operates its generating system when it has received a non-zero dispatch instruction. This is separate to the capability requirement under S5.2.5.11. The Commission considers that it is appropriate that this obligation only applies to generators that are dispatched for greater than zero MW and that the requirement does not apply to generators that are dispatched for zero MW, nor does it apply to loads that are dispatched to consume electricity from the system.

The Commission also notes that arrangements for energy storage systems will be considered through the upcoming rule change, *Integrating energy storage systems into the NEM*. AEMO has stated that, if a new category of Registered Participant is created to cover owners/operators of batteries, it will review the PFRR to address their inclusion at that time.[204]

### Specification in the NER that generators are not required to maintain headroom

As set out in section A.3, a number of stakeholders are concerned that any proposal to mandate the provision of additional headroom (stored energy for frequency control) could lead to substantial ongoing costs for generators.

The Commission acknowledges that AEMO's rule change request did not include a requirement that generators maintain headroom, and that the draft PFRR specifically states that the provision of additional headroom is not required in order to comply. The Commission considers it appropriate that AEMO has the power to adjust the PFRR from time to time in order to manage the technical performance criteria and settings for generation plant that are connected to the national electricity system and are registered to participate in the NEM. However, the Commission notes that, in the context of addressing the immediate concerns with power system frequency control, this power need not extend to decisions around the requirement for generators to maintain additional stored energy for frequency control.

Indeed, any future obligation that results in a large cross-section of the generating fleet maintaining stored energy would likely impose substantial costs on generators that outweigh the additional benefits this might provide to the security of the power system. Therefore, the final rule provides that the PFRR cannot require generators to maintain additional stored energy as a condition of complying with the requirements of the PFRR. This aspect of the

204 AEMO, submission to the consultation paper, pp.7-8.

final rule provides greater clarity and certainty to generators and will limit the likelihood of substantial unwarranted costs being incurred by generators in the future.

The Commission also acknowledges stakeholder concerns that a mandatory PFR arrangement that does not include headroom may undermine the effectiveness of contingency market ancillary services which provide reserve capacity to rebalance the power system following a contingency event. This concern is based on the theory that continuous generator governor response may lead to a portion of the reserve capacity procured through the contingency FCAS markets being utilised for normal frequency management. This may lead to an under-delivery of contingency FCAS following a contingency event and poorer system frequency performance.

The Commission notes that the scenario described above is unlikely and is directly contradicted by the results AEMO expects for the power system with narrow band frequency response provided universally by scheduled and semi-scheduled generators. In practice, the proportional movement of generators away from their dispatch set points as a result of frequency bias response is likely to be less than 1 per cent of the units rated capacity. This is evidenced by the results of AEMO's WEM case study shown in Figure A.5.1.[205]

Mandatory primary frequency response is not expected to detrimentally impact the operational or physical effectiveness of existing FCAS. However, the Commission notes that under the NER, AEMO is responsible for specifying the characteristics of the market ancillary services and procuring sufficient quantities of each to maintain system security and meet the requirements of the frequency operating standard during normal operation and following contingency events. As AEMO becomes aware of any changes in the operating characteristics of the power system, such as the under-delivery of contingency FCAS, it is reasonable to expect that its procurement practices would be adjusted to accommodate the operational changes. [206]

#### No requirement to renegotiate agreed generator performance standards

The Commission notes stakeholder concerns that the obligation to comply with the PFRR could potentially require Generators to conduct modelling and renegotiate their connection agreement and generator performance standards under clause 5.3.9 of the NER.

Clause 5.3.9 outlines the procedure a Generator must follow when proposing to alter a connected generating system or a generating system for which performance standards have been previously accepted by AEMO and the relevant NSP. Broadly, clause 5.3.9 requires that if a Generator alters aspects of its generating system and (amongst other things) that alteration will affect the performance of the generating system relative to certain technical requirements in Schedule 5.2, the generator must provide both AEMO and its connecting Network Service Provider:

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205 AEMO, WEM Primary Frequency Response Case Study, 19 December 2019

206 An example of this is the changes that AEMO have recently been making in respect of the assumed value for load-relief in the mainland power system. These changes are being made to reflect changes in the nature of equipment connected to the power system and the impact this has on power system behaviour following a contingency event. As a result of these changes the quantity of contingency services purchased by AEMO will increase. Ref. https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/load-relief

- a description of the alteration and a timetable for its implementation
- modelling data in accordance with the Power System Model Guidelines, Power System Design Data Sheet and Power System Setting Data Sheet
- amendments to the Generator's performance standards; and
- if necessary, a proposed system strength remediation scheme.

Some of the technical requirements in Schedule 5.2 that could trigger the clause 5.3.9 process include changes to droop and maximum allowable deadbands (S5.2.5.11), and response times (S5.2.5.7 and S5.2.5.8) and active power control (S5.2.5.14).

The Commission understands that, were the mandatory PFR requirement to require Generators to provide modelling and negotiate their performance standards, it would mean significant cost and administrative burden for market participants, NSPs and AEMO.

The final rule provides that cl. 5.3.9 does not apply in relation to any modifications made to a generating system by a scheduled generator or semi scheduled generator in order to comply with the PFRR as applicable to that generating system. Consistent with the rest of the mandatory arrangements, this is reversed in the sunset provisions.

#### Constitutional concerns

In its submission to the consultation paper, Snowy Hydro stated that s 51(xxxi) of the Australian Constitution empowers the Commonwealth to make laws with respect to the acquisition of property on just terms from any State or person for any purpose in respect of which the Parliament has power to make laws. Snowy Hydro stated that "the mandatory nature of PFR and the direct benefit to AEMO as a result of the PFR strongly suggests it involves an acquisition of property, enlivening s51(xxxi)". Therefore, Snowy Hydro stated that "the proposed compensation arrangements must be on 'just terms…' or otherwise the PFR requirements risks being found constitutionally invalid".

The Commission responded to this claim in the submission summary of the draft determination. The Commission said that the draft rule, if made, would not amount to an acquisition of property for the purposes of s 51(xxxi) of the Constitution as it did not constitute a modification or extinguishment of property rights nor a corresponding acquisition of property rights. In addition, although s 51(xxxi) applies in relation to the NER as applied by Commonwealth legislation in offshore areas, and as a result of equivalent legislation in the Territories, it does not apply in relation to the NER as applied in the participating States. Further, the prohibitions that exist in the offshore areas and Territories do not constitute a general limit on the AEMC's rule making power.

In its submission to the draft determination, Snowy Hydro stated that the Commission had not adequately established the constitutional validity of the proposed rule. Snowy Hydro further stated that the fact that s 51(xxxi) does not apply to every jurisdiction in which the NER is imposed does not resolve the constitutional issue. Snowy Hydro said that the Commission's consideration of whether or not the proposed rule constitutes an "acquisition of property" for the purposes of s 51(xxxi) "is devoid of legal analysis and insufficient, amounting to no more than a mere declaration that no such acquisition will take place".

Snowy Hydro stated that the draft rule required "the forcible provision of primary frequency control from Generators and such provision will result in an identifiable benefit relating to the use of property (being the power stations from which the primary frequency control is supplied). As such, the proposed rule is likely to give rise to a relevant acquisition". Snowy Hydro did not provide any additional legal analysis as to how the draft rule would give rise to an acquisition of property for the purposes of s 51(xxxi).

The Commission considers that the final rule will not give rise to an "acquisition of property" for the purposes of s 51(xxxi) of the Constitution. To meet that description, it must result in both: a modification or extinguishment of property rights; and a corresponding acquisition of property rights.[207]

There are two different types of "acquisition" for the purposes of s 51(xxxi):

1. the acquisition of title to a party's property and the extinguishment of that party's property rights (direct acquisition); and
2. impairment or extinguishment of a party's rights in an item of property and the conferring of a corresponding proprietary benefit on another party such that, even though the second party does not acquire the first party's title to the property, it can be said that an acquisition of property has occurred (indirect acquisition).[208]

The final rule does not involve any compulsory acquisition of title to the property of Generators. Therefore, no question of direct acquisition arises.

Further, the requirement of the final rule that Generators use their generating plant to respond to changes in system frequency does not result in an indirect acquisition of a Generator's proprietary rights in the generating plant by AEMO or any other party. It simply requires the Generators to use their property in a particular way. Property is not "acquired" merely because legislation requires a party to use the party's property in particular ways for the benefit of others.[209]

Any benefits that may accrue to AEMO, or any other party, under the final rule are not proprietary in nature. The avoidance of liabilities that AEMO might have incurred in the absence of the rule change is not a proprietary benefit. Nor are the regulatory benefits that are likely to flow from the rule. It is likely that a court would recognise, analogously with the *Plain Packaging Case*, that the proposed rule "reflects a serious judgment that the public purposes to be advanced and the public benefits to be derived from the [rule] outweigh those public purposes and public benefits which underpin the … property rights … enjoyed by the [Generators]" and that the rule achieves its objectives "without effecting an acquisition".[210]

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207 "To bring the constitutional provision into play it is not enough that legislation adversely affects or terminates a pre-existing right that an owner enjoys in relation to his property; there must be an acquisition whereby the Commonwealth or another acquires an interest in property, however slight or insubstantial it may be": *The Commonwealth v Tasmania (*Tasmanian Dam Case*)* (1983) 158 CLR 1 at 145 (Mason J), quoted with approval in *Australian Tape Manufacturers Association Ltd v The Commonwealth (*Tape Manufacturers*)* (1993) 176 CLR 480 at 499-500 (Mason CJ, Brennan, Deane and Gaudron JJ). See also *Tasmanian Dam Case* (1983) 158 CLR 1 at 247-248 (Brennan J).

208 See, e.g. *ICM Agriculture* (2009) 240 CLR 140 at [139] (Hayne, Kiefel and Bell JJ).

209 See e.g. *Australian Capital Television Pty Ltd v The Commonwealth* (1992) 177 CLR 106 at 166 (Brennan J); *Plain Packaging Case* (2012) 250 CLR 1 at [43] (French CJ), [191] (Hayne and Bell J).

210 *Plain Packaging Case* (2012) 250 CLR 1 at [43] (French CJ).

In addition, the NER have always required Generators to operate their generating systems in accordance with generator performance standards and other requirements under the Rules. The right to participate in the NEM, and also the right to participate in the FCAS market, are therefore "inherently susceptible" to modification and extinguishment and accordingly the rule does not result in an "acquisition" of any such right.[211]

Finally, even if a court were to accept that the proposed rule results in a "taking" of Generators' property and a corresponding proprietary benefit to AEMO or another party, this would likely be characterised as an "adjustment of competing rights" that does not amount to an acquisition of property. In *Nintendo Co Ltd v Centronics Systems Pty Ltd*, it was held that a modification of intellectual property rights was not an acquisition because "a law which is not directed towards the acquisition of property as such but which is concerned with the adjustment of the competing rights, claims or obligations of persons in a particular relationship or area of activity is unlikely to be susceptible of legitimate characterization as a law with respect to the acquisition of property".[212] That statement also applies to the NEM, in which AEMO and Generators are in "a particular relationship [and] area of activity".

***Application of s 51(xxxi)***

Given that the Commission does not consider that the final rule results in an acquisition of property, any analysis of the application of s 51(xxxi) to the NER as applied in each participating jurisdiction is largely academic. However, in order to address Snowy Hydro's submission on this point, the Commission has set out the below analysis.

Section 51(xxxi) provides the Commonwealth Parliament with a legislative power of acquiring property, while at the same time imposing a condition that the power cannot be exercised without also providing for compensation on just terms. Importantly, s 51(xxxi) does not provide for a general right to compensation for acquisition of property, but rather operates as a limit on Commonwealth legislative power and does not affect the legislative powers of the States. Unlike the Commonwealth, State Parliaments have power to pass laws for the compulsory acquisition of property without compensation because there is no provision equivalent to s 51(xxxi) in any of the State Constitutions.

The AEMC is established under South Australian legislation, which provides that the AEMC has the rule-making functions conferred on it under the National Electricity Law (NEL). The NEL is also set out in South Australian legislation and is applied by Application Acts in: each State except Western Australia; both Territories; and the offshore area of each State and Territory. The NEL provides that the AEMC may make National Electricity Rules, subject to certain statutory requirements. The NEL and the NER have the force of law in each participating jurisdiction pursuant to the legislation of that jurisdiction. In making a rule, the AEMC is required to have regard to the national electricity objective.

As they apply in each participating State, the NEL and the NER are not subject to a "just terms" requirement as set out in s 51(xxxi), because the Constitutions of those States do not impose such a requirement. As they apply in the ACT, the Northern Territory and the

211 See *Cunningham v The Commonwealth* (2016) 259 CLR 536 at [45]-[47] (French CJ, Kiefel and Bell JJ), [289] (Gordon J)

212 (1994) 181 CLR 134 at 161 (Mason CJ, Brennan, Deane, Toohey, Gaudron and McHugh JJ)

offshore area of each State and Territory, the NEL and the NER are subject to such a "just terms" requirement because: the Commonwealth Application Act is subject to the limitation in s 51(xxxi) of the Constitution; and the Territory Application Acts are subject to similar limitations under the Commonwealth legislation that provides legislative powers to the Territories.

However, the Commission does not consider that the "just terms" requirement in s 51 (xxxi) of the Constitution is a general limit on the AEMC's power to make rules. It is only a limit on the legislative powers of the Commonwealth and the Territories. Therefore, if the AEMC were to make a rule that resulted in the acquisition of property other than on just terms (for the purposes of s 51(xxxi)), that rule would not (for that reason) be wholly invalid. The rule would validly apply in each participating State. However, as noted above, the question of validity is not relevant in the present circumstance as the final rule does not give rise to an acquisition of property.

### A.5.2 Governance arrangements

**Specification of a lower limit for mandatory frequency response deadband**

The frequency operating standard (FOS) is set by the Reliability Panel. It sets out the operational requirements for power system frequency in the NEM by defining the allowable power system frequency range for a certain set of power system conditions.

Under the current arrangements, AEMO operates the power system, including through the dispatch of electricity and market ancillary services in accordance with the FOS during normal operation and following contingency events.

The FOS therefore provides transparent and definitive guidance to AEMO to operate the power system to a standard that benefits market participants and provides a reliable supply of electricity to consumers.

The intent of AEMO's *Mandatory primary frequency response* rule change request is not to revise the FOS itself, but instead to change the operating requirements for generating plant in the NEM as the means of achieving improved frequency performance. AEMO's rule change request suggested that the desired frequency performance ought to be defined through the obligations placed on market participants through the primary frequency response requirements (PFRR). The generator frequency response deadbands proposed in AEMO's proposed rule, and in Dr. Sokolowski proposed rule, therefore operate as a quasi-system standard. The Commission expects that following full implementation of the PFRR, this improved frequency performance would effectively mean that the current requirements of the FOS would be exceeded.

The Commission considers that in general it is appropriate for AEMO to manage the technical performance criteria and settings for generation plant that are connected to the national electricity system and that are registered to participate in the NEM. However, the Commission considers that the maximum allowable frequency response dead band is a key variable associated with the proposed rule. This setting has implications not only for the secure and stable operation of the power system but also for the economic operation of the NEM.

Where a particular setting has broader economic or market impacts it may be more appropriate for that setting to be determined by the AEMC or the Reliability Panel to make economic trade-offs with consideration of the national electricity objective. However, given the need for an immediate policy change to restore effective frequency control in the NEM, the Commission agrees with AEMO's position that it is not appropriate to consider revising the FOS and determining a new market or performance-based mechanism at this time. Such a policy approach would lead to a delayed implementation of a solution to the immediate power system frequency issues.

The final rule introduces a new term in Chapter 10 of the NER — the *primary frequency control band* — outside of which AEMO may set the mandatory primary frequency response deadband that applies to generators. The *primary frequency control band* is set at the range of 49.985Hz to 50.015Hz (±0.015Hz) (or such other range as specified by the Reliability Panel in the power system security standards) and is expressed as a minimum bound, meaning that an individual generator may provide a frequency response at a deadband wider than this range if agreed with AEMO but will not be required to provide a frequency response to a deadband that is within this range. This frequency range is consistent with AEMO's rule change request.

On account of the importance and broader implications of this setting, the Commission has determined that the final rule authorises AEMO to specify a maximum allowable frequency response dead band in the PFRR, but that the NER specifies a lower bound for the maximum allowable frequency response band (the *primary frequency control band*). In the absence of a clearly defined frequency performance standard in the FOS, the Commission has determined that the minimum bound for the maximum allowable deadband be specified in the NER, and not subject to full discretion by AEMO in the PFRR. This is consistent with the pre-NEM arrangements in the National Electricity Code that included the specification of the maximum allowable deadband for generating units, rather this being in subsidiary documents or standards.

The *primary frequency control band* is also a key variable in the implementation of the AEMC's future reform pathway and it is therefore appropriate that the band be specified in the NER to allow the AEMC to review and revise this setting at a future date.

The specification of the *primary frequency control band* in the NER or by the Reliability Panel is not intended to create the impression that generators must operate their plant to that band or that a narrower response band is not allowed under the NER. Generators would be able to operate their plant on a narrower deadband if they chose to.

The Commission recognises that narrow band primary frequency response from all capable generation plant is likely to achieve the operational objectives identified by AEMO in its rule change request, namely:[213]

- Re-establish effective control of power system frequency, and thereby align the NEM with standard international practice.

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

- Increase the resilience of the power system to disturbances, particularly events beyond simple credible contingency events.
- Ensure a predictable frequency response from generation to power system disturbances, to support power system planning and modelling.

However, the Commission also recognises that a mandatory requirement for narrow band PFR may not be the only viable solution that achieves the identified objectives. Other potential solutions may include a mandatory frequency response backstop as a wider frequency band complemented by the introduction of new incentive or market arrangements to provides sufficient narrow band PFR on a continuous basis to help control frequency during normal operating conditions. Consideration of such alternative options aligns with stakeholder views that it may be more appropriate for a mandatory primary frequency response band to be set at a wider range than the ±0.015Hz proposed by AEMO.

The Commission acknowledges stakeholder concerns around the setting of the *primary frequency control band* at ±0.015Hz including that this setting is narrower than the previous mandatory frequency response band of ±0.05Hz that applied in the NEM prior to 2003.[214] In particular the Commission notes the proposal put forward by the AEC that the *primary frequency control band* be initially set at ±0.05Hz and be reviewed and potentially revised by the Reliability panel at a later date. The Commission acknowledges the AEC proposal, however, it does not align with the technical advice provided by AEMO and the advice from AEMO's expert consultant, Dr John Undrill.[215] Therefore, the final rule retains the setting for the primary frequency control band of ±0.015Hz as proposed by AEMO. The appropriateness of the *primary frequency control band* and the interaction of it with the operation of the FCAS markets and related arrangements will be considered by the Commission through the assessment of the *Removal of disincentives to primary frequency response* rule change and any other relevant rule change requests received.

Stakeholders also raised concerns in relation to the potential risks and challenges associated with the activation of changes to generator frequency response settings, including the generator governor dead bands. The Commission considers that AEMO is well-placed to manage the operational challenges associated with the implementation of the mandatory PFR arrangement, including any staging of changes to generator control systems and the tuning of these settings to deliver effective system frequency control. The Commission considers that this process will be supported through the collaboration of AEMO and individual market participants. Therefore, the final rule requires AEMO to consult with stakeholders and document the process for the coordinated activation of plant changes through the development of the interim *Primary Frequency Response Requirements*.

Finally, the Commission notes that the *Mandatory primary frequency response* rule is an interim arrangement that includes sunset provisions which will repeal the arrangement on 4 June 2023. The Commission considers that the introduction of this interim arrangement for mandatory narrow band PFR will allow time for further consideration of how power system

214 NECA, Technical standards code changes gazetted 27 March 2003. S5.2.6.4 deleted and replaced with S5.2.5.11

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

frequency performance is specified in the Frequency operating standard and the design of appropriate tools to enable AEMO to effectively manage the power system in accordance with the Frequency operating standard. This review will be considered as part of the future reform pathway described in chapter 3 of this final determination. Following the consideration of the appropriateness of the setting for the *primary frequency control band* the Commission may request that the Reliability Panel review the Frequency operating standard and consider the specification for frequency performance during normal operation and the setting for the *primary frequency control band*.

#### Interactions with the generator access standards

The new requirement for generators to be frequency responsive in accordance with the PFRR is consistent with and coexists alongside the existing requirements for frequency control capability set out in S5.2.5.11 of the NER.

The Commission notes AEMO's proposal in its submission to the consultation paper that the generator access standards for frequency control under S5.2.5.11 in the NER be amended to remove any potential ambiguity with respect to the PFRR. AEMO proposed that compliance with the automatic and minimum access standards would be 'subject to the *primary frequency response requirements*. The Commission has considered AEMO's proposal and has determined not to include this proposed change as part of the final rule.

The Commission considers that the performance requirements specified by AEMO in the PFRR should not take priority over the minimum and automatic generator access standards set out under clause S5.2.5.11 of the NER. That is, the PFRR should not require a generator to operate in a way that is inconsistent with the requirements for frequency control capability set out in S5.2.5.11. Any changes to the capability requirements for new connecting generation should be undertaken through the rule change process. By including AEMO's proposed wording as part of S5.2.5.11, the access standards would in effect be subordinate to any future changes to the PFRR.

The Commission considers that the conditions set out in the PFRR should be specified so as not to conflict with the generators access standards as set out in the NER. Indeed, the Commission acknowledges AEMO's statement in its submission on the consultation paper that the capabilities required under the draft PFRR are not more onerous than the access standards on clause S5.2.5.11, or in other existing minimum access standards in clause S5.2.5.

In addition, given that the final rule places a primary frequency response requirement on all scheduled and semi-scheduled generation, which would meet AEMO's system security needs, then any changes to the generator access standards are unnecessary and duplicative.

The final rule includes a note following S.5.2.5.11(b)(2) and S.5.2.5.11(c)(2) to refer to and clarify the different obligations that apply to generators in relation to frequency control capability and operation:

- Clause 4.4.2(b) of the *Rules* sets out the obligations on *Generators* in relation to compliance with the technical requirements in clause S5.2.5.11, including being capable of operating in *frequency response mode*
- Clause 4.4.2(c1) of the *Rules* sets out the obligations on *Scheduled* and *Semi-Scheduled Generators* in relation to the operation of their *generating systems* in accordance with the *Primary Frequency Response Requirements*.

## BOX 4: EXISTING REQUIREMENTS FOR FREQUENCY CONTROL CAPABILITY

Clause S5.2.5.11 of the NER includes minimum and automatic technical requirements for a generating system in relation to frequency control.

The general requirements for generator frequency control include that the generating system must be capable of:

- setting a frequency response deadband within the range of 0 to ± 1.0 Hz
- setting a droop within the range of 2% to 10%.

The minimum access standard for generator frequency control requires that:[2]

- in response to a rise in system frequency, a generator's output must not worsen an over frequency situation
- in response to a fall in system frequency, a generator's output must not decrease more than 2% per Hz
- the generating system must be capable of operating in a frequency response mode such that, subject to energy source availability, it responds to a rise in frequency by decreasing power output and responds to a decrease in frequency by increasing power output.

The automatic access standard for generator frequency control states 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.[3]

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

Source: National electricity rules, version 129.
Note: 1. NER Clause S.5.2.5.11(i)(2)
Note: 2. NER Clause S.5.2.5.11(c)
Note: 3. NER Clause S.5.2.5.11(b)

# B EXEMPTIONS FROM THE PFR REQUIREMENT

The final rule includes an exemption framework that enables Generators to apply to AEMO for an exemption or variation from the primary frequency response parameters applicable to a generating system as set out in the *PFRR*. The final rule also includes a list of principles that AEMO must have regard to when approving exemptions and variations from the *Primary frequency response requirements*.

This appendix describes the Commission's considerations in relation to the exemption framework that is included in the final rule.

## B.1 Proponents views

### B.1.1 AEMO's proposal

AEMO has indicated that it expects many generators would not need to make substantive changes to their plant control systems to meet the requirements of the proposed rule, other than perhaps reducing the deadbands outside which frequency response was delivered, or selecting their plant load controllers to operate in a manner that supports frequency response.[216] AEMO's intent is that such plant would be required to comply with the primary frequency response performance requirements set out in the PFRR.

In its rule change request, AEMO recognised that there were likely to be some generating plant for which it is uneconomic to apply the mandatory PFR requirement. AEMO's intention is that generation plant that is not technically capable of providing PFR in accordance with the PFRR be eligible for exemption or variation to the PFR requirement.[217]

AEMO's proposed rule included provision for AEMO to approve a variation or exemption for a generator in respect of any performance parameter for PFR. Under its proposed rule, AEMO would set out the conditions for granting such a variation or exemption in its PFRR.[218]

AEMO's preliminary PFRR includes the following guidance in relation to the process and criteria for AEMO providing exemptions to the proposed PFR requirement:[219]

- A full exemption may be provided where plant is inherently incapable of making control system changes to be compliant with the PFRR, or that significant plant augmentation would be required to be compliant.
- A partial exemption or variation to the requirement may be provided if AEMO determines that full compliance with the technical requirements would adversely impact system security.

AEMO's preliminary PFRR also included provision for standing exemptions to be in place for:

- The steam turbine component of a combined cycle gas generator.
- A generating system operating in synchronous condenser mode.

216 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, p.29.

217 Ibid.

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

219 AEMO, Draft Primary frequency response requirements, 17 October 2019, p.9.

In addition, AEMO's proposed rule applies the mandatory primary frequency response requirement to all market participants registered as scheduled and semi-scheduled generators. AEMO's proposed rule would not apply to participants in the NEM that are registered as non-scheduled generators.[220] This effectively exempts generators with a nameplate rating less than 30MW that export less than 20GWh in any 12-month period, as such generators are not required to register as scheduled and semi-scheduled generators.[221]

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

### B.1.2 Dr. Sokolowski's proposal

Dr Sokolowksi's rule change request, *Primary frequency response requirements*, did not include any provision for exemption or variation of the requirement to provide primary frequency response.

## B.2 Stakeholders' views on the consultation paper

A number of stakeholders expressed support for the inclusion of an exemption process as part of AEMO's proposed rule, *Mandatory primary frequency response*.[222]

Some stakeholders requested further detail and transparency in relation to how the exemption process proposed by AEMO would work in practice.[223]

Alinta Energy raised concerns that if a substantial portion of the generation fleet were exempted from the proposed mandatory requirement, the cost of providing frequency response in accordance with the requirement may be significantly increased for the remaining responsive portion of the fleet. As such Alinta Energy urged that:[224]

> any exemption criteria must be drafted precisely to ensure appropriate definitions exist which methodically outline a stringent criterion to whom exemptions can apply and under what specific grounds...

While the CEC supported the inclusion of an exemption process as part of a mandatory PFR requirement, it also noted that:[225]

> Further details are needed from AEMO on what would constitute 'significant augmentation' so generators can appropriately assess if they would be exempt. We also suggest the AEMC consider the inclusion of these exemption provisions within the NER.

**IES proposed an alternative approach**

220 Refer to NER rule 2.2.3

221 AEMO, Guide to NEM generator classification and exemption, August 2014, p.14.

222 Submissions to the consultation paper: Alinta Energy, p.4.; CEC, p.4.; Hydro Tasmania, p.2.; Meridian Energy, p.5.; Tilt Renewables, p.2.;

223 Submissions to the Consultation paper: CEC, p.4.; Energy Australia, p.7.; Stanwell p.6.;

224 Alinta Energy, Submission to the Consultation paper, pp.4-5.

225 CEC, Submission to the Consultation paper, p.4

IES suggested an alternative exemption approach, where a standing exemption would apply to generators with a nameplate capacity less than 200MW. IES reasoned that these large generating plant typically already have the capability to provide narrow band PFR and that this capability can be activated at relatively low cost. Furthermore, IES reasoned that it is likely to be more costly and problematic for smaller generating plant to comply with the PFRR due in part to the increased proportion of variable renewable generation and battery energy storage systems.[226]

## B.3 Stakeholders' views on the draft determination

Most stakeholders, including CleanCo, ERM Power, the CEC, Hydro Tasmania, TasNetworks and Origin generally supported the draft exemptions framework and criteria.[227] However, many stakeholders, including AEMO, the AEC, AGL, and the CEC suggested additional criteria and amendments.[228]

AEMO proposed the final rule should:

- amend clause 4.4.2B(a)(2) to:
  - use 'modifying' instead of 'augmentation', given 'augmentation' has a specific definition in the NEM which is not appropriate in this clause
  - restrict any consideration of Generator revenue to that from the energy and ancillary service markets, based on past performance
  - not refer to 'hours of operation', as this is redundant and could be unclear
- specify that any commercially sensitive information Generators provide to AEMO to seek an exemption or variation under the PFRR (such as that required under clause 4.4.2B(a)(2) and 4.4.2B(a)(4)) is confidential information as defined in the NER.[229]

These and other stakeholder suggestions are addressed below in Table B.1.

## B.4 Commission's analysis

### BOX 5: SUMMARY OF FINAL RULE

The final rule includes an exemption framework that is based on the approach set out in AEMO's proposed rule. The final rule introduces a new clause 4.4.2A(b)(2) which requires that the PFRR include the conditions or criteria for Generators to request, and AEMO to approve, an exemption or variation from the requirements specified by AEMO in the *Primary frequency response requirements*. The Commission agrees that AEMO is the appropriate party to administer the exemption process since they are the system operator and so have the technical information required to assess both costs, as well as the effect that the exemption

226 IES, Submission to the Consultation paper, p.4.

227 Submissions to the draft determination: CleanCo, ERM Power, the CEC, Hydro Tasmania, TasNetworks and Origin.

228 Submissions to the draft determination: AEMO, AEC, AGL, CEC.

229 AEMO, Submission to the draft determination, p.8-9.

would have on frequency performance.

The final rule introduces a new clause 4.4.2B which sets out the following criteria which AEMO must have regard to in considering such a request:

> the capability of the *generating system* to operate in *frequency response mode;*
>
> the stability of the *generating system* when operating in *frequency response mode,* and the potential impact this may have on *power system security;*
>
> any other physical characteristics of the *generating system* which may affect its ability to operate in *frequency response mode*, including (but not limited to) *dispatch inflexibility profile,* operating requirements, or *energy constraints;* and
>
> whether the *Scheduled Generator* or *Semi-Scheduled Generator* has been able to establish to *AEMO's* reasonable satisfaction that the implementation of the *primary frequency response parameters* applicable to that *Scheduled Generator's* or *Semi-Scheduled Generator's generating system* will be unreasonably onerous having regard to, amongst other things
>
> (i) the likely costs of modifying the *generating system* to be able to operate in *frequency response mode;* and/o
>
> (ii) the likely operation and maintenance costs of operating the *generating system* in *frequency response mode;*
>
> relative to the revenue earned from the provision of *energy* and *market ancillary services* by the *generating system* in relation to its operation in the *NEM* during the 12 months prior to the date of the application for exemption or variation, as applicable...

The final rule also clarifies that information provided to AEMO as part of an application for variation or exemption is confidential information.

As described in Appendix A, the objective for the final rule is that all technically capable scheduled and semi-scheduled generation comply with the proposed PFR requirement.

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. The capability from these generators 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.

In the absence of an exemption framework, some generators may be forced to incur substantial costs for plant upgrades to comply with the PFR requirement. An effective exemption framework can introduce a degree of flexibility that avoids excessive compliance costs for eligible generation plant while still delivering on the system security and frequency control objectives. The exemption framework in the final rule provides for this flexibility while at the same time setting out a series of principles to improve the transparency of the exemption process, while also still meeting the immediate system security needs.

**Changes between the draft and final rule**

The main changes in the final rule in relation to the exemption framework are:

- The exemption principles set out in Cl 4.4.2B(a) have been re-ordered in the final rule.
- The exemption principles that relate to upfront and ongoing costs have been combined under the new sub-paragraph (4). This sub paragraph has been revised to reflect the intent that an applicant for an exemption or variation to the PFRR should establish, to AEMO's satisfaction, that operation in accordance with the default requirements of the PFRR will be unreasonably onerous. The application for an exemption or variation should have regard to:
  - (i) the likely costs of modifying the *generating system* to be able to operate in *frequency response mode;* and
  - (ii) the likely operation and maintenance costs of operating the *generating system* in *frequency response mode*,

    The consideration of whether the likely upfront and ongoing costs are unreasonably onerous shall be made relative to the revenue earned from the provision of *energy* and *market ancillary services* by the *generating system* in relation to its operation in the NEM during the 12 months prior to the date of the application for exemption or variation, as applicable.
- The final rule includes a new sub-paragraph in clause 4.4.2B to clarify that cost information provided by a generator to AEMO as part of a request for an exemption or variation to the requirements under the PFRR is confidential information.

### Objective of the exemption framework

The exemption framework in the final rule is designed to avoid excessive costs that may otherwise be incurred through the application of the mandatory PFR requirement to the entire generation fleet. This is consistent with AEMO's proposed rule, which exempted Generators from the PFR requirement where it was not feasible for their generating systems to comply.[230] The final rule is designed to meet the immediate system security need for improved frequency performance while avoiding excessive associated costs.

The Commission considers that an effective and transparent exemption framework can add a degree of flexibility to a mandatory primary frequency control requirement. While it is expected that some proportion of the generation fleet would meet the technical requirements

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

for primary frequency response without the need for expensive plant upgrades, this will not be the case for the entire generation fleet. Some generating plant are not inherently able to comply with the proposed primary frequency response requirements, and it is expected that these plant would incur significant costs if they were required to do so. Therefore, the Commission recognises the importance of including a provision for generators to obtain exemptions or variations to AEMO's proposed PFRR where it can be demonstrated that the costs of compliance would be likely to be excessive.

The Commission considers that in some cases the upfront and operating costs of requiring a generator to comply with the PFRR may be challenging to absorb and as such may represent a business risk. While if the costs for all businesses are the same, then these can be passed on to consumers jointly, the Commission still has concerns about the 'edge' cases where there may be a disconnect between when the costs would be incurred and when they would be recovered. If costs were challenging to absorb for a short time period, then this would constitute a business risk and potentially risks to reliability. Therefore, the exemption principles include provision for a Generator to request a variation or exemption from the requirements of the PFRR on the grounds that compliance would be unreasonably onerous, based on an assessment against their revenue.

The exemption principles in the final rule provide a transparent framework to avoid excessive costs and risks associated with the application of a mandatory primary frequency response requirement to all scheduled and semi-scheduled generators in the NEM. At the same time, the exemption framework should not be so lenient as to undermine the broad based nature of the proposed mandatory PFR arrangement. As discussed in Appendix A, AEMO's advice is that the entire fleet should provide primary frequency response, and indeed, to do this, potentially could be cheaper than just a subset of the fleet. Therefore, it is important that the exemption framework does not unnecessarily exempt parties.

**Commission's analysis**

The Commission agrees with AEMO and stakeholders that an exemption process is likely to improve the flexibility and transparency of a mandatory PFR rule. In developing the final rule, the Commission considered how prescriptive the rule should be in relation to an exemption process. The Commission recognises that the degree to which the exemption process is set out in the rules impacts on the transparency, workability and flexibility of the rule. The Commission considers that a principles-based approach is in the best interests of AEMO and market participants.

There are a number of ways in which the Commission could introduce a greater degree of prescription into the exemption framework. Exemptions could be determined by generating technologies, tasks, or a simple cost threshold. Greater prescription would provide market participants with the increased transparency and certainty as to how the rule impacts their operations. However, a prescriptive approach would also reduce the flexibility of the mandatory PFR rule which may result in excessive costs, if too few generators are exempt, or diminish AEMO's ability to manage the security of the power system, if too many generators are exempt.

In response to the consultation paper, IES proposed that a mandatory PFR requirement should be applied to generation with a nameplate capacity over 200MW. The Commission noted in the draft determination that this approach would exempt approximately 20GW (38 per cent), of the existing 53GW of registered generation in the NEM.[231] It is understood that defining a sub-set of the generation fleet in this way does not align with AEMO's objectives for power system frequency control as set out in its rule change request, which was to maximise the proportion of the fleet providing primary frequency response. AEMO considers that the operational objectives are best served through the application of the mandatory primary frequency response requirement to all capable scheduled and semi-scheduled generators in the NEM.[232]

In the context of applying a mandatory requirement for generators to be frequency responsive, as noted above, the Commission considers that AEMO is best placed to make decisions as to which plant should be granted exemptions or variations from the PFRR. However, the Commission agrees with the submissions from the CEC, Energy Australia and Stanwell that it is appropriate for the rule to provide AEMO with additional guidance in relation to the exemption process. As set out above, the final rule includes a set of five criteria that AEMO must consider in assessing an exemption or variation from the PFRR.

**Changes from the draft rule**

The Commission agrees with AEMO's recommendations set out in section B.3 and has amended the exemption principles in the final rule in line with AEMO’s proposed changes.

The Commission acknowledges stakeholder requests for further detail on how AEMO will assess the technical and economic viability to determine exemptions and variations, including that:

- AEMO should consider both upfront and operational costs for generators
- ongoing expenses should be relative to the size of each generator.

The draft rule introduced a new clause 4.4.2B which sets out the following criteria which AEMO must have regard to in considering requests for exemption or variation:

1. the capability of the generating system to operate in frequency response mode;
2. the costs that are likely to be incurred in augmenting the generating system to be able to operate in frequency response mode, relative to the turnover derived from, and operating hours of, the generating system in relation to its operation in the *national electricity market*;
3. the stability of the generating system when operating in frequency response mode, and the potential impact this may have on power system security;
4. the ongoing costs of operating the generating system in frequency response mode; and
5. any other physical characteristics of the generating system which may affect its ability to operate in frequency response mode, including (but not limited to) dispatch inflexibility profile, operating requirements, or energy constraints.

231 AEMO, Generation information, 14 November 2019

232 AEMO, Submission to the Consultation paper, p.4.

The final rule reorders the draft principles and merges draft principles two and four into a new principle, clause 4.4.2B(a)(4), which makes several changes to the draft rule to provide more clarity on how AEMO should consider generator revenue and costs to assess requests for variations and exemptions from the performance parameters set out in the PFRR.

Clause 4.4.2B(a)(4) in the final rule provides guidance that a Generator requesting a variation or exemption should establish to AEMO's reasonable satisfaction that implementing the required primary frequency response parameters applicable to the relevant generating system will be unreasonably onerous. The case for the requirement being unreasonably onerous must have regard to the costs likely to be incurred in modifying the generating system to operate in frequency response mode, or the likely ongoing costs of operating the generating system in frequency response mode relative to the revenue earned by the generating system in relation to its operation in the NEM during the 12 months prior to the date of the application for exemption or variation, as applicable. This clarifies the process and responsibilities for AEMO and Generators in relation to a request for variation or exemption from the performance parameters set out in the PFRR.

The drafting of Clause 4.4.2B(a)(4) narrows the relevant revenue streams to those that AEMO already has access to and avoids potential complexity and ambiguity about which revenue streams may be considered in relation to a request for exemption or variation.

Clause 4.4.2B(a)(4) of the final rule refers to 'modifying' instead of 'augmentation', given 'augmentation' has a specific definition in the NEM which is not appropriate in this clause. In the final rule, this clause no longer refers to 'hours of operation' to avoid redundancy and ambiguity.

The following table summarises the Commission's response to stakeholder recommendations on the draft determination's exemptions framework.

Table B.1: **Response to stakeholder recommendations on draft exemptions framework**

| ISSUE | STAKEHOLDER COMMENT | FINAL RULE RESPONSE |
|---|---|---|
| Confidentiality of commercially sensitive information<br><br>(AEMO) | Specify that any commercially sensitive information Generators provided to AEMO to seek an exemption or variation under the PFRR (clause 4.4.2B(a)(4)) is confidential information as defined in the NER. | **Cl 4.4.2B is amended to clarify that information provided to AEMO as part of an application under 4.4.2B(a)(4) is confidential information.**<br><br>The Commission considers that the interests of market participants are likely to be protected through clarification that commercially sensitive information provided to AEMO is confidential information, |

| ISSUE | STAKEHOLDER COMMENT | FINAL RULE RESPONSE |
|---|---|---|
| | | while noting that this information would likely meet the current Chapter 10 definition of confidential information in any event. |
| General catch-all principle<br><br>(AEMO) | An additional principle should be included that allows AEMO to consider other matters in its assessment of exemptions. | **No change**<br><br>The Commission considers that it is not necessary to include an additional 'catch-all' principle. While AEMO must have regard to the listed principles in clause 4.4.2B(a), it is not limited to considering only these criteria. AEMO may consider other matters when assessing exemptions. |
| Upfront costs<br><br>(AEMO) | That the final rule:<br>• use 'modifying' instead of 'augmentation', given 'augmentation' has a specific definition in the NEM which is not appropriate in this clause<br>• restrict any consideration of Generator revenue to that from the energy and ancillary service markets, based on past performance<br>• not refer to 'hours of operation', as this is redundant and could be unclear. | **Cl 4.4.2B(4) is amended in line with AEMO's suggestions**<br><br>The Commission supports AEMO's proposed changes to the drafting for cl 4.4.2B in relation to the consideration of upfront costs. |
| Ongoing costs<br><br>(CleanCo) | The final rule clarify that ongoing expenses should be relative to the size/output of each generator. | **Cl 4.4.2B(4) is amended in line with CleanCo's request**<br><br>The Commission supports Clean Co's proposed changes in relation to the |

| ISSUE | STAKEHOLDER COMMENT | FINAL RULE RESPONSE |
|---|---|---|
| | | consideration of ongoing operational costs incurred as a result of complying with the PFRR. The changes to 4.4.2B(a)(4) will effectively account for the size/output of the generating unit. The principle considers the ongoing operational and maintenance costs of operating each unit in frequency response mode relative to the revenue earned from energy and FCAS over the previous 12-month period. |
| Standing exemptions<br><br>(CleanCo) | Include standing exemptions in the NER, including the proposed standing exemptions for steam turbine components of CCGT plant and generators operating in synchronous condenser mode.<br><br>Generators with a capacity less than 30MW should be granted a standing exemption. | **No change**<br><br>The Commission does not agree that standing exemptions should be included in the NER for the following reasons:<br>• AEMO is best placed to consider the specific technical and operational characteristics of individual generation types and technologies<br>• To include such detailed technology-based information in the NER would increase the rigidity of the MPFR arrangement. |
| Body responsible for administering exemption framework<br><br>(AEC, ERM, Infigen, Stanwell) | The AER, not AEMO, should administer the exemption framework. | **No change**<br><br>The Commission does not consider that it is appropriate for the AER to administer the exemption framework. The assessment of applications for |

| ISSUE | STAKEHOLDER COMMENT | FINAL RULE RESPONSE |
|---|---|---|
| | | exemptions requires detailed understanding of operational matters related to individual generators and the broader system impacts and power system needs.<br><br>AEMO is best placed to manage the exemption process. |
| Dispute resolution<br><br>(AGL) | Disputes related to requests for exemption be settled using independent expert advice. | **No change**<br><br>The NER dispute resolution process will apply. This process is coordinated by the AER with the help of a dispute resolution adviser who provides independent expert advice (NER rule 8.2.). |
| Maximum compliance costs limit<br><br>(the AEC) | Set a maximum acceptable limit for upfront compliance costs with reference to 1-2% of annual generator revenue from the energy market. | **No change**<br><br>The Commission is confident that updated exemptions framework in the final rule will best determine when exemptions should apply to generators based on compliance costs.<br><br>Setting a limit without similar rigorous analysis risks applying a cap that is too high or low to be effective. |
| Independent expert advice<br><br>(AGL) | Exemption disputes should be settled using independent expert advice. | **No change**<br><br>The Commission notes that Rule 8.2 potentially allows for independent experts to provide advice as part of disputes between Participants (e.g. AEMO and obligated Generators). |
| Environmental and safety requirements | Exemptions framework should consider environmental and | **No change**<br><br>The Commission notes that |

| ISSUE | STAKEHOLDER COMMENT | FINAL RULE RESPONSE |
|---|---|---|
| (Origin, CS Energy, Meridian Powershop) | safety obligations, such as water release requirements for hydro units. | clause 4.9.4 of the NER restricts generators from sending out energy if it would threaten public safety or create a material risk to the environment. The exemptions framework in the final rule allows AEMO to have regard to these requirements. |

Source: Submissions to the draft determination: Origin, CS Energy, Meridian Powershop, AGL, AEC, AGL, ERM, Infigen, Stanwell, CleanCo, AEMO.

# C IMPLEMENTATION AND TRANSITIONAL ARRANGEMENTS

This appendix sets out the steps and timetable for implementing the rule, including the steps that will need to be taken by AEMO to develop and implement the interim *Primary frequency response requirements (PFRR)*.

The substantive parts of the final rule implementing the mandatory primary frequency response requirement will commence on 4 June 2020.

This appendix also sets out the transitional clauses that will commence on the date the rule is made.

## C.1 Proponents' views

### C.1.1 AEMO's views

AEMO's proposed rule includes a framework for implementation of the mandatory primary frequency response requirement that is set out in proposed transitional rules.[233] The key elements of AEMO's implementation process for its proposed rule include that:

- AEMO is to develop and publish an interim *Primary frequency response requirements* to apply from the commencement date of the rule
- the interim *Primary frequency response requirements* specify the date by which generators must comply with the obligation, which may vary by plant type
- generators may submit a claim to AEMO for reimbursement of costs associated with plant upgrades to become compliant with the *Primary frequency response requirements*.
- n relation to costs incurred by AEMO for reimbursing generators for approved plant upgrade costs, AEMO may recover these costs through participant fees.

#### Implementation plan in AEMO's draft *Primary frequency response requirements*

In addition to the proposed transitional arrangements for implementation of its proposed rule, AEMO provided to the Commission a draft *Primary frequency response requirements* which provides an indication of its proposed process and time frame for activation of changes to generator control systems. The process and time frames set out in AEMO's draft *Primary frequency response requirements* include:[234]

- Scheduled and semi-scheduled generating systems with a nameplate rating of 200 MW or more must complete a self-assessment of the ability of their generating system to meet the technical requirements and submit this to AEMO within 60 business days of the commencement date for the *Primary frequency response requirements.*
- Scheduled and semi-scheduled generating systems with a nameplate rating less than 200 MW must complete a self-assessment of the ability of their generating system to meet

233 AEMO, 2019, Rule change proposal: Mandatory primary frequency response, p.45..

234 AEMO, Primary frequency response requirements - draft version 1.1, 17 October 2019, p.8.

the technical requirements and submit this to AEMO within 120 business days of the commencement date for the *Primary frequency response requirements.*

- AEMO will respond to each generator within 20 business days of receiving its self-assessment.

The preliminary draft *Primary frequency response requirements* does not include a date by which generators must comply with the obligation, as proposed under AEMO's proposed transitional rules. The Commission understands that AEMO would need to set out this detail at a later date, prior to the commencement of the interim *Primary frequency response requirements.*

**AEMO's understanding of the scale of expected plant upgrade costs**

AEMO has indicated that it expects the cost of changes to generators' plant control systems to comply with the technical requirements for primary frequency response to be relatively minor for most generating systems.[235] AEMO's submission to the consultation paper explained that its specification of the technical requirements for primary frequency response was conceived on the basis that the most onerous change that a generator might have to undertake would be a change in control system settings. Its submission noted that:[236]

> AEMO is aware that some generating systems can make control system changes to become compliant with the PFRR at near zero cost, and at very short notice. AEMO is also aware that more significant, time consuming, complex and costly changes may be required for other generating systems.

AEMO indicated that it may grant a full or partial exemption from the technical requirements for primary frequency response where the upfront costs for plant upgrades are unreasonable and the exemption would not adversely impact on power system security.[237]

### C.1.2 Dr. Sokolowski's views

Dr Sokolowski did not include any commentary on implementation and transitional arrangements in his proposed rule change request or rule drafting.

## C.2 Stakeholder views on the consultation paper

This section summarises the views of stakeholders in relation to the implementation of a mandatory primary frequency response requirement based on submissions received in response to the consultation paper, *Primary frequency response rule changes*.

### C.2.1 Implementation process

A number of generators expressed concerns in relation to the implementation process and time frames set out in AEMO's proposed rule and its draft *Primary frequency response requirements.* Generators were concerned that the hasty or uncoordinated implementation of

235 Ibid. p.55.

236 AEMO, Submission to the consultation paper, 31 October 2019, p.8.

237 Ibid.

changes to generator control systems may pose risks to generation plant and power system security including:

- risk of generators interacting with each other to cause hunting and oscillations in power system frequency.[238]
- risk of early movers bearing a disproportionate increase in operating costs. [239]
- risk of unintended consequences due to the proposed deadband of ±0.015Hz being untested in the history of the NEM. [240] For example, Alinta Energy consider that the implementation of the proposed mandatory PFR requirement may undermine the operation of thermal generators during low load conditions or fast ramping conditions.[241]

Meridian Energy expressed support for the proposed 120 business-day period for self assessment of generators under 200MW, while also noting that the justification for the 60 business-day self-assessment time frame for larger generators is not clear.[242]

Alinta Energy also expressed concern that AEMO's proposed time-frame of 60 business days for self-assessment of large generators >200MW is unreasonably short and that an expedited approach to implementation of plant changes may drive scarcity pricing for the specialised engineering services required to advise on changes to generation control systems. Alinta Energy suggested that:[243]

> A progressively implemented and ordered reduction in dead band settings over a period of 12-18 months (at a minimum) in order to progressively monitor the performance of frequency of the NEM appears a more appropriate solution.

Energy Australia noted that:[244]

> AEMO's Primary Frequency Response Requirements (PFRR) document provides no details around how AEMO would manage implementation

Infigen suggested that, while a more comprehensive market solution is being developed, the implementation of the mandatory PFR requirement could follow an extended staged approach based on the implementation tranches set out by AEMO in its rule change request. Under its proposed approach, Infigen suggested that AEMO could:[245]

> - Initially, seek a mandatory response from large synchronous units (200 MW+) and observe the resulting frequency performance (6-12 months);
> - If insufficient, then seek response from smaller synchronous units;

238 Submissions to the consultation paper: ERM Power, p.9; Stanwell, p.5.
239 Submissions to the consultation paper: Energy Australia, p.6; Stanwell, p.6.
240 Submissions to the consultation paper: Alinta Energy, p.3; ERM Power, p.9; Delta Electricity, p.1.
241 Alinta Energy, Submission to the Consultation paper, p.3.
242 MEA Group, Submission to the consultation paper, p.3.
243 Alinta Energy, Submission to the consultation paper, p.5.
244 Energy Australia, Submission to the consultation paper, p.7.
245 Infigen, Submission to the consultation paper, pp.7-8.

- Finally, if performance is still unsatisfactory, and a market mechanism has not been developed, seek response from non-synchronous units, where [the] cost of provision is likely to be highest.

### C.2.2 Recovery of upfront costs

A number of generators were supportive of AEMO's proposed process to reimburse generators for costs associated with plant changes to provide PFR in accordance with the proposed *Primary frequency response requirements*.[246]

Origin Energy noted that any consideration of upfront costs should include costs associated with updating generator models.[247]

Energy Australia noted that consideration of upfront costs should take into account costs associated with outages for generation plant to make the required changes.[248]

## C.3 Stakeholder views on the draft determination

### C.3.1 Implementation

Under the draft rule, AEMO is responsible for coordinating the implementation of the MPFR requirement. AEMO is required to consult on and document the process for coordinating changes to generation plant in the interim PFRR.

In response to the draft determination, Snowy Hydro, AGL, ERM Power, CS Energy, Origin, Delta and Infigen stated that implementing a narrow frequency response deadband of +-0.015Hz on the entire generation fleet could have unintended and unforeseen detrimental impacts including:

- oscillations and impacts on power system frequency stability
- reduced investment in FCAS capability
- overprocurement of PFR relative to system needs.[249]

AGL, CEC, ERM Power and Tesla supported a staged implementation of the final rule with review and hold points.[250] They suggested that the final rule could be implemented with an initial wider deadband or MW capacity thresholds for the PFR activation tranches in the NER. AEMO could monitor, evaluate and report on power system frequency performance during the implementation process to identify the effects of the mandatory PFR requirement has on the system at these settings. These reports could identify whether the frequency performance objective is met, which could justify whether or not to move to tighter deadbands or different MW capacity thresholds.

246 Submission to the consultation paper: Alinta Energy, p.4; Delta Electricity, p.16; MEA Group, p.4.
247 Origin Energy, Submission to the consultation paper, p.4.
248 Energy Australia, Submission to the consultation paper, p.7.
249 Submissions to the draft determination: Snowy Hydro, p. 2, 3; AGL, p. 2; CS Energy, p. 4; Origin, p.4; Delta, p. 5; Infigen, p.1.
250 Submissions to the draft determination: AGL, p.3; CEC, p.4; ERM Power, p.4; Tesla, p.6-7.

Stakeholders consider that such an approach could help minimise the risk of unintended and unforeseen detrimental impacts and limit implementation to that required for effective frequency control.

### C.3.2 Reporting on frequency performance

The AEC and ERM Power proposed that the final rule expand on AEMO's recently introduced frequency performance reporting obligation under NER cl 4.8.16 to include additional metrics related to the provision of PFR and the resulting impact on frequency performance.[251]

### C.3.3 Publication of performance parameters

The AEC proposed that AEMO should be required to publish aggregate PFR quantities to improve transparency.[252] Snowy Hydroand Stanwellrecommended that AEMO publish additional data on exemptions, such as deadband settings, droop settings and response times.[253] Snowy Hydro suggested that data, as well as stored headroom, should be published in real-time.

### C.3.4 Upfront cost recovery

In their submissions to the draft determination, AGL and Enel X agreed with the Commission's position that generators should not be compensated for upgrade costs because generators could seek to gold-plate upgrades, generators can derive revenue from any necessary upgrades, and would be exempt from upgrades if the costs are too high.[254] Enel X also identified that reimbursing generators for upfront costs would potentially provide them an unfair advantage in FCAS markets. (However, Enel X did suggest that it may be useful to reward generators for providing frequency response to cover their ongoing operational costs).

However, other stakeholders, including Infigen and the AEC, did not support an uncompensated mandatory PFR requirement, citing increased costs for generators.[255] CleanCo, Goldwind, and Meridian Powershop recommended that the rule should compensate generators for upfront compliance costs.[256]

## C.4 Commission's analysis and conclusions

> **BOX 6: SUMMARY OF FINAL RULE**
>
> The final rule requires AEMO to develop interim *Primary frequency response requirements* to

251 Submissions to the draft determination: AEC, p4; ERM Power, p5.
252 Australian Energy Council, Submission to the draft determination, p.4
253 Submissions to the draft determination, Snowy Hydro, p.4; Stanwell, p.9.
254 Submissions to the draft determination: AGL, p.3; Enel X, p.12.
255 Submissions to the draft determination: AEC, p.1 ; Infigen, p. 1.
256 Submissions to the draft determination: CleanCo, p.1; Goldwind, p.2; Meridian Powershop, p.4.

be in place prior to the commencement date of the rule on 4 June 2020. AEMO has confirmed that it is comfortable with this commencement date.

In addition to the technical criteria for the provision of PFR, the interim *Primary frequency response requirements* would also document AEMO's process for coordinating changes to generation plant associated with activation of the frequency response mode as intended by the *Mandatory primary frequency response* rule. This process would include the date by which each generator must comply with the performance requirements set out in the *Primary frequency response requirements*.

AEMO's proposed rule included transitional arrangements for Generators to submit a claim for reimbursement of costs associated with plant upgrades to become compliant with the *Primary frequency response requirements*, and for AEMO to recover its associated costs through participant fees. The Commission does not consider that it would be necessary or appropriate to reimburse market participants for costs associated with complying with the proposed PFR requirement. Therefore, the final rule:

- does not include any transitional arrangements for affected generators to be directly reimbursed for plant upgrade costs;
- does not include any transitional arrangements for AEMO to recover such associated costs through market participants fees.

**Changes between the draft and final rule**

There are no changes between the draft and final rule for this aspect.

### C.4.1 Implementation

This section describes the transitional rules included in the final rule. The transitional rules set out:

- The process for AEMO to develop and publish the interim *Primary frequency response requirements* to apply from the commencement date of the rule.
- The content of the interim *Primary frequency response requirements,* including documentation of the process for the coordinated activation of changes to generation plant.

**Development of the interim *Primary frequency response requirements***

Consistent with AEMO's proposed rule, the final rule includes transitional arrangements that require AEMO to prepare interim *Primary Frequency Response Requirements* to apply from 4 June 2020. As proposed by AEMO, the interim *Primary Frequency Response requirements* will set out:

- The information required under new clause 4.4.2A(b) including:
    - the technical requirements for Primary frequency response

- the process for generators to request a full or partial exemption from the *Primary Frequency Response requirements.*

- The date, which may vary by plant type, by which Scheduled Generators and Semi-Scheduled Generators must effect changes to their plant to comply with the Interim *Primary frequency response requirements*.

The Commission acknowledges stakeholder concerns in relation to the coordination of plant changes associated with the implementation of the mandatory primary frequency response requirement. To address these concerns the more preferable final rule also requires that:

- AEMO consult with stakeholders on the development of the interim *Primary frequency response requirements* - AEMO to publish a draft Interim *Primary frequency response requirements* by 9 April 2020 and invite stakeholder submissions on this draft for a period of 20 business days.
- The interim *Primary frequency response requirements* document AEMO's process for the coordinated activation of changes to generation plant.

The time-frames set out in the final rule for the development of the interim *Primary frequency response requirements* are summarised in Table C.1. The Commission understands from AEMO that the commencement date of 4 June 2020 will not delay the overall implementation of the mandatory PFR requirement. This date represents the latest date that AEMO may publish the interim *Primary frequency response requirements*. The final rule authorises AEMO to commence its consultation earlier and be able to publish the interim *Primary frequency response requirements* earlier at its discretion. Given the immediate need for improved frequency control identified by AEMO in its rule change request, the Commission encourages AEMO to investigate options to bring forward the generator self-assessment process to expedite the time frame for activation of changes to generator control systems to provide PFR in accordance with the interim *Primary frequency response requirements*.

**Table C.1: Time-frames under the final rule for development of the interim *Primary frequency response requirements***

| DATE | ACTION |
|---|---|
| 26 March 2020 | The AEMC publishes the final determination and final rule, *Mandatory primary frequency response*<br>Commencement date for the transitional rules set out in schedule 3 of the Amending Rule. |
| 9 April 2020 | AEMO publishes a draft interim *Primary frequency response requirements* |
| (+ 20 business days)<br>7 May 2020 | Close of submissions on the draft interim *Primary frequency response requirements* |
| 4 June 2020 | AEMO publishes the interim *Primary frequency response requirements* |

| DATE | ACTION |
|---|---|
| | Commencement date for the substantive elements of the rule, *Mandatory primary frequency response,* as set out in schedule 1 of the Amending Rule. |

### Changes from the draft rule

The draft determination acknowledged stakeholder concerns in relation to the coordination of plant changes associated with the implementation of the mandatory primary frequency response requirement. However, the issues that stakeholders raise to justify a more prescriptive approach in the rules relate to operational matters for implementing the mandatory approach which AEMO is best placed to manage, including:

- specifying generators into the different implementation tranches, by MW threshold or otherwise
- the timeframes and process for implementation, including staging and hold points.

The Commission considers that AEMO is responsible for implementing the final rule and for general system operation. The final rule provides AEMO the capacity to apply settings to different generators to sufficiently 'tune' the system and avoid potential oscillations and impacts on system frequency stability. Similarly, AEMO can vary regulation and contingency FCAS markets and can monitor FCAS markets for potential risks.

As discussed further below, AEMO is already required to publish weekly and quarterly reports on frequency performance in the NEM. These reports will provide transparency as to the effectiveness of the MPFR implementation process.

As such, the final rule makes no changes to the current NER provisions relating to AEMO’s implementation of the mandatory primary frequency response requirements.

## C.4.2 Reporting on frequency performance

AEMO is currently required to publish weekly and quarterly reports on frequency performance under NER clause 4.8.16.

The NER require AEMO to report weekly on the following with respect to frequency performance outcomes:

- an indicative comparison of power system frequency performance against the following measures specified in the frequency operating standard:
    - the proportion of time that the frequency of the power system was inside of the normal operating frequency band
    - the recovery times to return to the normal operating frequency band where frequency left the normal operating frequency band;
    - the time error requirements.
- the regulation services that were dispatched by AEMO in each region

- measures indicating the proportion of dispatched regulation services that were used by AEMO.

The NER also require AEMO to report quarterly with respect to power system frequency:

- where applicable, AEMO's assessment of the impact of any actions taken by AEMO to improve power system frequency control outcomes
- AEMO's assessment of the achievement of the frequency operating standard, including (where applicable) an analysis of how and why the frequency operating standard was not met
- the rate of change of power system frequency associated with the largest frequency deviation, and any other significant frequency deviation, in each month
- AGC estimates of the additional electrical power (in MW) required to be produced or consumed to correct a given power system frequency deviation (known as the 'area control error')
- a list of any reviewable operating incidents that affected power system frequency.

The Commission considers that the existing frequency performance arrangements in the NER provide transparency as to AEMO's operation of the power system and should be sufficient to inform market participants as to the effectiveness of MPFR. In particular, the requirement in the NER that AEMO report on the impact of any actions taken by AEMO to improve power system frequency control, while being a more general obligation than the specific metrics proposed by stakeholders, should cover the additional information requested by stakeholders.

There may be diminishing benefits in the rules being more prescriptive in relation to the exact metrics which AEMO must report on. The reporting requirements recently introduced into the NER balance setting prescriptive requirements within the NER against providing AEMO with flexibility to develop and report on additional metrics based on changing power system conditions, if required.

As such, the final rule makes no changes to the current NER provisions relating to AEMO's frequency performance reporting requirements.

### C.4.3 Publication of performance parameters

Clause 4.4.2A(c) in the final rule requires AEMO to publish on its website and maintain, a register of scheduled and semi-scheduled generators who have been granted a variation or exemption from any primary frequency response parameters in the PFRR.

In response to stakeholders' submissions on the draft determination, the Commission considers that it is not necessary to require in the NER that AEMO must publish the agreed PFR performance parameters for all generators to provide adequate transparency on the performance of the market or the mandatory requirement. The Commission considers that the reporting requirements for AEMO in the final rule are sufficient.

The Commission notes that the rules do not prohibit AEMO from publishing performance parameters agreed under the PFRR, subject to stakeholder consultation and consideration of any request for such information to be treated as confidential information.

### C.4.4 Upfront cost recovery

Existing generators required to comply with the *Primary frequency response requirements* would likely incur one-off upfront costs, as acknowledged in Appendix A. These costs are likely to be different for each generator. As noted by AEMO, some generation plant are likely to meet the technical requirements for primary frequency response with minimal need for plant changes, and at relatively low upfront cost. Other generation plant would require more significant plant upgrades and control system tuning in order to provide primary frequency response in accordance with the technical requirements.

The Commission does not consider that the final rule places any additional obligations on connecting Generators, over and above the existing requirements for frequency control capability set out in Clause S5.2.5.11.[257] Therefore, the consideration of cost recovery for upfront costs is limited to the impacts on and arrangements for existing Generators.

The Commission has considered two alternative approaches by which existing generators may recover these upfront costs:

1. Direct reimbursement of approved costs from AEMO to affected participants similar to the arrangement in AEMO's proposed rule
2. No direct reimbursement — generators would recover their costs through their participation in the energy and ancillary service markets.

The Commission's investigation of reasons for and against the direct reimbursement of plant upgrade costs is set out below.

#### Reasons not to provide direct reimbursement of plant upgrade costs

In considering whether to make a final rule that includes the direct reimbursement and cost recovery arrangements included in AEMO's proposed rule, the Commission notes that compensation is not typically provided to affected parties for the costs associated with complying with an amendment to the NER. The following reasons support the determination of a final rule that does not provide for direct reimbursement of plant upgrades costs:

- The inclusion of an arrangement for direct reimbursement of plant upgrade costs provides little incentive for affected generators to minimise the costs of plant upgrades. This exposes consumers to the risk that the total cost of plant upgrades exceeds the minimum necessary cost to deliver the required level of frequency improvement.
- In most cases, generator upgrades will contribute to the development of a capability that may be utilised by affected generators to obtain a revenue stream for frequency response through the present and future market arrangements for FCAS.
- The costs for plant upgrades and control system changes are expected to be relatively minor and manageable for most affected generators. Where the costs of plant upgrades are more substantial, it is intended that a generator will be eligible for a full or partial exemption from the requirement to avoid or reduce the upfront cost. The final rule

257 Since 5 October 2018, connecting Generators are required to have the capability to operate in a frequency response mode and be capable of setting a droop within the range 2% - 10% and a deadband within the range 0 to ± 1.0Hz. NER Clause S.5.2.5.11(c)(2) and NER Clause S5.2.5.11(i)(2).

includes a framework for generators to request an exemption from all or part of the *Primary frequency response requirements*. This exemption framework is described in Appendix B.

**Potential reasons to provide direct reimbursement of plant upgrade costs**

The Commission has considered whether there are any reasons for the final rule to provide for existing generators to be directly reimbursed for approved plant upgrade costs to comply with the primary frequency response requirement.

The following scenarios may support the inclusion of a provision for direct reimbursement of generator upgrade costs as part of a final rule for mandatory primary frequency response:

- if transitional assistance were required for plant upgrades to be undertaken in an expedited time frame
- if the costs of complying with the rule were such that failure to provide direct reimbursement of costs would undermine the commercial viability of participants in the NEM or constitute a significant risk to future investment.

Each of these scenarios is discussed below.

***Consideration of the time frame for compliance with the final rule***

The Commission has considered whether there is any justification for paying compensation to existing generators on the basis that they may incur higher upfront costs than would normally be expected due to an expedited requirement to implement plant changes to comply with the final rule.

The Commission considers that the proposed time frame for implementation of the draft rule and subsequent implementation of plant changes is reasonable, noting AEMO's understanding that for many generators the expected plant changes are relatively minor and can be undertaken at short notice.[258]

AEMO's proposed implementation plan includes a staged approach under which technically capable generators with a nameplate rating over 200 MW would be expected to implement plant changes first. The remaining technically capable generating systems would be expected to implement plant changes at a later date.[259]

Where changes to generation plant to comply with the primary frequency response requirement are more complex, costly or time-consuming, the final rule provides for an exemption process which requires AEMO to consider, among other things, the costs associated with plant augmentation to comply with the *Primary frequency response requirements.* The exemption framework is described in Appendix B.

In the context of the proposed exemption process and the staged implementation of plant changes, the Commission does not consider that direct compensation is justified on account of any expedited implementation of the mandatory primary frequency response requirement.

258 AEMO, Submission to the consultation paper, 31 October 2019, p.8.

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

***Consideration of impacts on investor confidence and the commercial viability of generation***

The direct reimbursement of some or all costs associated with compliance with a regulatory change may be justified where the costs associated with the new regulatory obligation are substantial, and affected participants are not able to effectively recover these costs through participation in the energy market. Under such a scenario, applying the new regulatory obligation in the absence of some level of compensation may constitute a material risk to the commercial viability of participants in the NEM or significantly undermine investor confidence.

The Commission has considered the scale of the expected costs associated with plant upgrades to comply with the primary frequency response requirement and whether it is reasonable to expect market participants to recover these costs through their participation in the energy market. The Commission notes that the final rule and current version of the *Primary frequency response requirements* include an exemption process that is intended to reduce or avoid excessive upfront costs for generators where plant upgrades may be more complex or costly.

The Commission has worked with AEMO to estimate the scale of the likely costs associated with required plant changes to comply with the technical requirements set out in the *Primary frequency response requirements.* The Commission's estimate of the total one-off upfront cost for the eligible generators to implement the required changes to their generating systems may be in the order of tens of millions of dollars across the entire generation fleet in the NEM. The Commission considers that the scale of these expected costs is relatively minor when compared with the $220 million annual cost of regulation FCAS in 2018 and the total annual value of energy turnover in the NEM in 2018/19 financial year of $18.3 billion.[260]

The Commission expects that the costs associated with plant upgrades to comply with the final rule are therefore not likely to constitute a substantive commercial risk to market participants, nor are they likely to significantly undermine investor confidence in future generation. Therefore, the Commission does not consider that direct compensation for upfront costs associated with compliance with the final rule is justified to make up for any associated commercial or investment risk.

**Conclusion**

The Commission considers that the inclusion of arrangements to compensate scheduled and semi-scheduled generators for the costs of complying with the final rule cannot be justified on any commercial, legal or economic grounds. Therefore, the Commission has made a more preferable final rule that does not provide for existing generators to claim for and receive compensation for approved plant upgrade costs. As a consequence, the more preferable final rule also does not include any arrangements for AEMO to recover its costs associated with reimbursing existing generators for approved plant upgrade costs.

The Commission recognises stakeholder concerns about upfront costs for generators, but has not provided a direct compensation framework in the final rule. The Commission is confident

260 AEMO, Quarterly energy dynamics - Q3 2019 workbook, 12 November 2019, Figure 27 - Quarterly FCAS costs by service. AEMO, AEMO Annual Report 2019, 15 October 2019, p.21.

that the exemption framework and implementation process will help minimise the up-front capital costs from implementing the mandatory requirement.

# D OTHER PROPOSED CHANGES

This appendix describes the Commission's considerations with respect to a number of other changes to the NER proposed by AEMO and Dr. Sokolowski in their rule change requests.

This appendix sets out stakeholders' views and the Commission's conclusions on these proposed changes.

- Section D.1. covers other proposed changes that relate to the provision of PFR, including to the arrangements in the NER that relate to:
  - contribution factors for allocation of the costs of regulation services
  - limitations on when a generator may send out energy
  - compliance with dispatch instructions
  - the technical performance standards that apply for the connection of generators to the power system.
- Section D.2. covers other proposed changes that do not directly relate to provision of PFR, including:
  - AEMO's responsibility to maintain and improve power system security
  - the arrangements in the NER for inertia and inertia support activities.

## D.1 Other changes related to primary frequency response

The rule change requests from AEMO and Dr. Sokolowski each proposed a number of other changes to the NER that relate to the provision of PFR. The rule change requests proposed changes to:

- Clause 3.15.6A(k) — relating to the determination of a contribution factor for the allocation of costs for regulating services
- Clause 4.9.4 — relating to the dispatch limitations that set out the conditions under which a scheduled and semi-scheduled generator may send out energy from its generation unit
- Clause 4.9.8 — relating to the general responsibility for a market participant to comply with a dispatch instruction given to it by AEMO
- Schedule S5.2.5.11 — relating to the technical performance standards for frequency control that apply for the connection of generators to the power system
- Schedule S5.2.5.14 — relating to the technical performance standards for active power control that apply for the connection of generators to the power system.

The final rule includes changes to NER cl 3.15.6A, cl 4.9.4, cl 4.9.8 and cl S5.2.5.11 that address the relevant issues raised in the rule change requests.

The final rule does not include any changes to Schedule S5.2.5.14.

The final rule is unchanged from the draft rule in relation to each of these aspects.

Each of these proposed changes are discussed in the following sections.

### D.1.1 Contribution factors for allocation of regulation costs

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.

Dr. Sokolowski proposed changes to clause 3.15.6A(k)(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 a uniform rate subject to the provision of PFR. This proposed change is intended to clarify that provision of PFR should not be judged to be contributing to the need for regulation services. [261]

#### Stakeholder views on the consultation paper

Ergon Energy and Energex generally supported the rules relating to removing disincentives to PFR as proposed by Dr Sokolowski.[262] Powershop also supports any changes to the Rules to remove disincentives to generators operating in frequency response mode and suggests an update to causer pays is necessary to align the causer pays process with these rule changes.[263]

However, CS Energy suggested Dr Sokolowski's amendment to clause 3.15.6A(k) may result in a change to the Causer Pays allocation calculations because it implies a different 'base' trajectory from which to calculate deviations. Given that the Causer pays procedure is a cost allocation process of secondary frequency control via regulating services, CS Energy considered that this change may have some unintended consequences. [264]

#### Stakeholder views on the draft determination

Stakeholders suggested that the Commission should further investigate causer pays arrangements and pursue potential reforms. The South Australian Government Department for Energy and Mining suggested that, given stakeholder concerns, the Commission should consider contribution factors as part of the *Removal of disincentives to the provision of primary frequency response under normal operating conditions* rule change.[265] Snowy Hydro suggested that determining a better cost allocation for causer-pays could help provide

261 Dr. Sokolowski, Primary frequency response requirement — Electricity rule change proposal, 30 May 2019, pp.2, 7, 9, 12.

262 Ergon Energy and Energex, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, p. 2

263 Powershop, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, p. 5

264 CS Energy, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, p. 18

265 South Australian Government Department for Energy and Mining, Submission to the draft determination, p.2.

incentives for tighter governor control.[266] Meridian Powershop recommended updating the causer pays mechanism given the draft rule has clarified these disincentives.[267] Meridian Powershop recommended that the Commission should conduct quantitative assessment to better understand how the proposed rule would reduce causer pays costs, and how causer pays costs are allocated across generators.[268]

#### Commission's analysis and conclusion

The Commission considers that the proposed change clarifies the intent of the NER in relation to the determination of contribution factors for the allocation of regulating services. NER clause 3.15.6A(k) provides a set of principles to guide AEMO in its development of a procedure for the determination of contribution factors for the allocation of costs associated with regulating services. The primary principle is that:[269]

> (1) the contribution factor for a Market Participant should reflect the extent to which the Market Participant contributed to the need for regulation services;

Clause 3.15.6A(k) also includes sub-paragraph (5) and (7) that specify scenarios where a scheduled participant or a semi-scheduled generator respectively, will not be assessed as contributing to the deviation in the frequency of the power system.[270] These provisions set out that if, within a dispatch interval, a scheduled participant or a semi-scheduled generator "achieves its dispatch target at a uniform rate", it will not be assessed as contributing to the deviation in the frequency of the power system.[271]

AEMO has indicated that the wording of clause 3.15.6A(k)(5)(i) and (7)(i) of the NER creates the impression that strictly following dispatch targets irrespective of frequency outcomes is ideal behaviour.[272]

The Commission considers that the proposed change to 3.15.6A(k)(5)(i) clarifies that provision of PFR by a scheduled participant should not be judged to be contributing to the need for regulation services as is the intent of the Causer Pays procedure. The Commission also considers that the proposed change should be reflected in 3.15.6A(k)(7)(i) as it applies to semi-scheduled generators.

The final rule is the same as the draft rule and includes the revision of clause 3.15.6A(k)(5)(i) to clarify that a scheduled participant will not be assessed as contributing to deviations in the frequency of the power system if:

266 Snowy Hydro, Submission to the draft determination, p.3.
267 Meridian Powershop, Submission to the draft determination, p.5.
268 Meridian Powershop, Submission to the draft determination, p.5.
269 NER Clause 3.15.6A(k)
270 NER Clause 3.15.6A(k) (5) & (7).
271 NER Clause 3.15.6A(k) (5)(i) & (7)(i).
272 AEMO, Removal of disincentives to primary frequency response — Electricity rule change proposal, 1 July 2019, p.25.

**3.15.6A(k)(5)**

**(i)** subject to the provision of *primary frequency response* by that scheduled Participant in accordance with the *Primary Frequency Response Requirements*, the Scheduled Participant achieves its *dispatch* target at a uniform rate;

Consistent with the draft rule, the final rule includes the revision of clause 3.15.6A(k)(7)(i) to clarify that a semi-scheduled generator will not be assessed as contributing to deviations in frequency of the power system frequency if:

**3.15.6A(k)(7)**

**(i)** subject to the provision of *primary frequency response* by that *semi-scheduled generating unit* in accordance with the *Primary Frequency Response Requirements*, the *semi-scheduled generating unit* achieves its *dispatch level* at a uniform rate;

The Commission agrees with stakeholders that further investigation into causer pays arrangements is necessary. It intends to undertake quantitative analysis in conjunction with AEMO and consider reforms to causer pays as part of the R*emoval of disincentives to the provision of primary frequency response under normal operating conditions* rule change and any other related rule change requests received.

### D.1.2 Limitations on when a generator may send out energy

AEMO proposed changes to the NER clause 4.9.4 in relation to the limitations on when a scheduled generator and a semi-scheduled generator may send out energy. The proposed changes to clause 4.9.4 clarify that both a scheduled and a semi-scheduled generator may send out energy from its generating unit as a consequence of operating in frequency response mode to adjust power system frequency in response to power system conditions.[273]

Dr. Sokolowski also proposed changes to 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, Dr. Sokolowski proposed alternative drafting to

273 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp.13, 45, 62.

clarify that a generating unit's frequency response mode shall be subject to local power system conditions.[274]

#### Stakeholder comments

CS Energy did not consider that Dr. Sokolowski's changes to clause 4.9.4(a)(4) were necessary provided the clauses "are not given their literal meaning".[275]

Delta Electricity supported the changes to clause 4.9.4 to address disincentives to PFR in the rules.[276]

Powershop, Enel X, TasNetworks, Enel Green Power, and Ergon Energy and Energex generally supported the proposed rule changes relating to clarification of the application of NER clause 4.9.4 as proposed by AEMO. [277]

No stakeholders commented on this issue in submissions to the draft determination.

#### Commission's analysis and conclusion

The Commission agrees with AEMO and Dr. Sokolowski that the proposed changes to clause 4.9.4 clarify that both scheduled and semi-scheduled generators can send out energy as a result of being frequency responsive. The Commission considers it desirable that all types of generators may provide PFR to the best of their capability. The provision of PFR involves the variation of the active power supplied by a generator to the grid and it is a common requirement for all generation plant to have this capability.[278]

The final rule is the same as the draft rule and includes changes to clause 4.9.4(a)(3) that align with the proposals from AEMO and Dr. Sokolowski, including the addition of clause 4.9.4(a)(3A) stating both scheduled and semi-scheduled generators may send out energy:

4.9.4(a)

(3A) as a consequence of its operation in *frequency response mode* to adjust *power system frequency* in response to *power system* conditions; or

### D.1.3 Frequency response and compliance with dispatch instructions

AEMO proposed changes to clause 4.9.8 of the NER in relation to the interaction of compliance with dispatch instructions and the operation of plant in a frequency response

274 Dr. Sokolowski, Primary frequency response requirement — Electricity rule change proposal, 30 May 2019, pp.3, 7, 9, 15.

275 CS Energy, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, pg. 18

276 Delta Electricity, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, pg. 20

277 Submissions on the consultation paper: Powershop, p. 5, Enel X, p. 7, TasNetworks, p. 3, Enel Green Power, p. 2, Ergon Energy and Energex, p. 2

278 NER Clause S5.2.5.11

mode. The proposed changes to clause 4.9.8 would clarify that operating in a frequency response mode does not constitute a breach of a generator's requirement to comply with its dispatch instructions.[279]

#### Stakeholder views on the consultation paper

AGL identified that generator perceptions that providing PFR would conflict with compliance with dispatch instructions as a key factor that drove generators to become frequency unresponsive, especially considering the AER's enforcement of this compliance. Many stakeholders agreed with AEMO that the NER should be revised such that it is clear that generators providing PFR are not breaching the obligation for them to comply with dispatch instructions. [280]

Stanwell requested clarification as to whether the proposal that generators are not penalised for PFR provision extends to ramping requirements.[281]

CS Energy did not consider that issues related to strict compliance with dispatch instructions were a continuing disincentive to PFR. [282]

As noted above, Enel X, TasNetworks and Ergon Energy and Energex also generally supported the proposed rule changes relating to removing disincentives to PFR as proposed by AEMO. [283]

### Stakeholder views on the draft determination

Stakeholders, including the South Australian Government Department for Energy and Mining, AGL and Meridian Powershop supported clarifying the rules to remove disincentives to PFR in line with Dr Sokolowski's proposal.[284]

#### Commission's analysis and conclusion

The Commission acknowledges the potential lack of clarity surrounding the relationship between a unit's compliance with dispatch instructions and the provision of PFR has caused concerns for many stakeholders. The Commission agrees with AEMO that the wording in clause 4.9.8 should be revised to clarify this matter.

The final rule includes changes to clause 4.9.8 to clarify that operating a plant in a frequency response mode is compatible with a generators' obligation to follow its dispatch instructions.

4.9.8

279 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp.13, 45, 62.

280 Submissions on the consultation paper: AGL, p. 1, HydroTas, p. 2, Kate Summers, p. 2, Stanwell, p.7, Powershop, p. 3, AEC, p. 2, Origin, p. 4, IES, p. 6, ERM, p. 9, Enel Green Power, p. 1.

281 Stanwell, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, pg. 7

282 CS Energy, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, pg. 6

283 Submissions on the consultation paper: Enel X, p. 7, TasNetworks, p. 3, Enel Green Power, p. 2, Ergon Energy and Energex, p. 2

284 Submissions to the draft determination: South Australian Government Department for Energy and Mining, p. 2; AGL, p.3; Meridian Powershop, p.3, 5.

(a1) A *Scheduled Generator* or *Semi-Scheduled Generator* is not taken to have failed to comply with a *dispatch instruction* as a consequence of its *generating unit* operating in *frequency response mode* to adjust *power system frequency* in response to *power system* conditions.

### D.1.4 Changes to NER clause S5.2.5.11

Through its submission to the consultation paper, AEMO proposed changes to the S5.2.5.11 to align it with the new PFR requirement in clause 4.4.2A and the PFRR. AEMO's rule change request identifies that some generators interpret clause S5.2.5.11(i)(4) of the NER as supporting or requiring them to turn off or counteract their plants responsiveness to frequency unless they are enabled for the provision of FCAS.[285]

#### Stakeholder views on the consultation paper

CS Energy and TasNetworks both considered AEMO's proposed changes to S5.2.5.11 were worthwhile. [286]

In its submission to the consultation paper, AEMO acknowledged the potential for unintended interpretations in relation to the new operational frequency control requirements in clause 4.4.2 (c1) and the *Primary frequency response requirements* (PFRR) alongside the existing frequency control requirement set out under clause S5.2.5.11.[287]

> AEMO considers that the capabilities required under the PFRR are not more onerous than the access standards in clause S5.2.5.11, or in other existing minimum access standards in clause S5.2.5.
>
> Nevertheless, AEMO recognises that two sets of requirements for frequency response could give rise to unintended interpretations.

AEMO included in its submission a proposed amendment to clause S5.2.5.11 to reduce the likelihood of any ambiguity. AEMO's proposed amendment includes a requirement under the automatic and minimum access standard in S5.2.5.11(b)(2) and S5.2.5.11(c)(2) for connecting generators to meet the requirements of the PFRR and removes the existing requirements in relation to the capability to set droop and deadband settings set out in S5.2.5.11(i)(2). [288]

No stakeholders commented on this issue in submissions to the draft determination.

#### Commission's analysis and conclusion

In relation to Dr Sokolowski's proposal to implement a mandatory requirement for PFR through clause S5.2.5.11, the Commission considers that an operational requirement for PFR

285 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp.13, 16-17, 45, 63.

286 Submissions on the consultation paper: CS Energy, p. 6, TasNetworks, p. 3

287 AEMO, Submission to the Consultation paper, 31 October 2019, pp. 6-7

288 Ibid., pp. 12-14

is more appropriately implemented through chapter 4 of the NER as proposed by AEMO in its rule change request, *Mandatory primary frequency response*. The Commission considers that it is not appropriate to include an operational requirement in S5.2.5.11 as this rule sets out the frequency control capability requirements for connecting generators.

The Commission's considerations in relation to the inclusion of a mandatory PFR requirement in the NER are covered in appendix A.

Regarding AEMO's proposed changes to clause S5.2.5.11(i)(4), the Commission acknowledges that this clause has caused some concern to generators and may lead to difficulty interpreting a generator's responsibilities in relation to frequency control. This clause is part of the general requirements for frequency control that apply to connecting generators. It states that:[289]

> 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;

S5.2.5.11(i)(4) was introduced into the NER on 5 October 2018 following the publication of the *Generator technical performance standards* rule on 27 September 2018. The final determination for the *Generator technical performance standards* rule set out the rationale for the inclusion of this sub-paragraph in the NER.  At that time, the Commission sought to clarify that the general requirements in S5.2.5.11 are for generators to demonstrate the capability to operate in frequency response mode as opposed to requiring a generator to operate in a frequency response mode and deliver an actual response. The drafting of this sub-paragraph was not intended to preclude or prevent a generator from operating in a frequency response mode when it is not enabled to provide FCAS. [290]

The Commission considers that, as S5.2.5.11(i)(4) has been misinterpreted to preclude a generator from operating in a frequency response mode when it is not enabled for a market ancillary service, there is likely to be a benefit in deleting this provision. The Commission considers that the requirements on generators to demonstrate frequency control capability are adequately specified by the remainder of S5.2.5.11 and that sub-paragraph (i)(4) does not improve the specification of the frequency control capability of a connecting generator. The final rule deletes clause S5.2.5.11(i)(4).

The Commission has considered AEMO's proposal to amend S5.2.5.11 to link the minimum access standard to the requirements in the PFRR and remove the capability requirements for droop and deadband. AEMO's proposal is intended to address potential ambiguity between S5.2.5.11 and the operational frequency control requirements set out in Clause 4.2.4A and the PFRR. While the Commission acknowledges the need for clarification in relation to the requirements for frequency control capability set out in S5.2.5.11 and the operational requirement set out in Clause 4.2.4A, the Commission does not agree with AEMO's proposed changes for S5.2.5.11(b)(2) and S5.2.5.11(c)(2) to be subject to the PFRR and for the existing capability requirements for droop and deadband to be removed. The Commission

289 NER clause S5.2.5.11(i)(4)

290 AEMC, *Generator technical performance standards* - Rule determination, 27 September 2018, p.58-59.

considers that the frequency control capability requirements for connecting generators should be independent of the operational requirements and that these capability requirements should not be subject to AEMO's PFRR. Therefore, the final rule does not include AEMO's proposed changes to S5.2.5.11(b)(2) and S5.2.5.11(c)(2), nor does it delete S5.2.5.11(i)(2).

The Commission recognises the potential benefit in providing additional clarity in S5.2.5.11 in relation to the operational requirement for frequency control. The final rule includes the following note after Clause S.5.2.5.11(b)(2) and S5.2.5.11(c)(2) in relation to the automatic and minimum access standards for frequency control:

> Note
>
> Clause 4.4.2(b) of the *Rules* sets out the obligations on *Generators* in relation to compliance with the technical requirements in clause S5.2.5.11, including being capable of operating in *frequency response mode*. Clause 4.4.2(c1) of the *Rules* sets out the obligations on *Scheduled* and *Semi-Scheduled Generators* in relation to the *Primary Frequency Response Requirements*.

### D.1.5 Active power control

Dr. Sokolowski proposed changes to clause S5.2.5.14 to 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.[291]

#### Stakeholder comments

CS Energy commented on this proposed change by Dr. Sokolowski. CS Energy does not believe the changes to S5.2.5.14 are necessary provided the NER is interpreted as a whole while recognising the dynamic nature of the power system.[292]

No stakeholders commented on this issue in submissions to the draft determination.

#### Commission's analysis and conclusion

NER clause S5.2.5.14 sets out the technical performance standards that apply to connecting generators in relation to active power control. While active power control is related to the provision of frequency response, the Commission considers that it is not necessary for the active power control requirements to be explicitly linked to system frequency. The requirements for frequency control capability are specified in clause S5.2.5.11, including the minimum access standard that requires a generator to be capable of varying its power transfer to the power system in response to a rise or fall in power system frequency measured at the connection point.[293] Therefore, the Commission considers the proposed

291 Dr. Sokolowski, Primary frequency response requirement — Electricity rule change proposal, 30 May 2019, pp.3, 7-9, 21.

292 CS Energy, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, pg. 6

293 NER Clause S.5.2.5.11(c)(2)

change to S5.2.5.14 does not provide a benefit in terms of improving the specification or clarity of the frequency control capability for connecting generators.

The final rule is the same as the draft rule and does not include any change to S5.2.5.14.

## D.2 Other changes

Dr. Sokolowski also proposed changes to certain clauses in the rules related to system security more generally, including proposed changes to:

- NER Clause 4.3.1 — relating to AEMO's responsibilities for power system security
- NER Clause 5.20B.5 — relating to the definition of inertia and inertia support activities

The final rule does not include any changes to these NER clauses. These positions are unchanged from the draft rule. The following section describes the Commission's considerations in relation to each of these proposals.

### D.2.1 AEMO's responsibility for power system security

Dr. Sokolowski proposed a revision to clause 4.3.1 of the NER to align it 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. [294]

#### Stakeholder vews on the consultation paper

Most stakeholders did not support the proposed change to NER clause 4.3.1. One exception was Powershop who agreed with the intent of Dr. Sokolowski's proposed change to clause 4.3.1.[295]

Ergon Energy and Energex commented that the proposed changes risk creating an "open statement" in relation to the obligations placed on AEMO, potentially leading to adverse impacts on customers.[296]

AEMO and Delta Electricity also did not consider Dr. Sokolowski's change to clause 4.3.1 to be necessary. [297]AEMO noted that:[298]

> As with the other functions listed in section 49 of the National Electricity Law, they are high-level, and the detail around each function is in the NER. [...] Replicating that function in clause 4.3.1 of the NER will not achieve the desired outcome.

CS Energy considered there to be no benefit in the proposed amendment to NER clause 4.3.1 given AEMO's requirement to improve power system security under NEL.[299]

294 Dr. Sokolowski, Primary frequency response requirement — Electricity rule change proposal, 30 May 2019, pp.3, 7-9, 12.
295 Powershop, Submission to the Consultation paper, 31 October 2019, p. 6.
296 Ergon Energy and Energex, Submission to the Consultation paper, 31 October 2019, p. 2.
297 Submissions to the consultation paper: AEMO, p. 10, Delta Electricity, p. 13.
298 AEMO, Submission to the Consultation paper, 31 October 2019, p.10.
299 CS Energy, Submission to the Consultation paper, 31 October 2019, p. 16

#### Stakeholder views on the draft determination

Meridian Powershop supported Dr. Sokolowski's proposal to amend clause 4.3.1 to explicitly refer to AEMO's responsibility to improve, in addition to maintain, power system security.[300]

#### Commission's analysis and conclusion

In relation to Dr. Sokolowski's proposal, the Commission notes that, in addition to AEMO's direct obligation under the NEL, the requirement for AEMO to maintain and improve power system security, consistent with its obligations under the NEL, is reinforced through NER clause 4.1.1(b).

> 4.1.1 (b) By virtue of this Chapter and the National Electricity Law, AEMO has responsibility to maintain and improve power system security.

The Commission considers that in the context of the existing reference under clause 4.1.1(b), the proposed change does not constitute a material benefit in terms of the understanding or the application of the NER.

The final rule is the same as the draft rule and does not include any revision to NER clause 4.3.1.

### D.2.2 Inertia support activities

Dr. Sokolowski's proposed rule also included changes to the NER clause 5.20B.5(a) to include an explicit reference to the provision of fast frequency response (FFR) from inverter-connected plant being an included inertia support activity. Dr. Sokolowski also proposed a revision to the chapter 10 definition of 'Inertia'. As noted in Dr Sokolowski's rule change request:[301]

> 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.

#### Stakeholder views on the consultation paper

Powershop did not consider the current framework for inertia support activities adequately supports the use of FRR by inverter connected plant and so agrees with Dr Sokolowski's proposed change to the definition of inertia.[302]

However, TasNetworks and Energy Networks Australia did not agree with Dr Sokolowski's proposed changes to the definition of inertia on the grounds that FFR is not interchangeable

300 Meridian Powershop, Submission to the draft determination, p. 6.

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

302 Powershop, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, pg. 6

with inertia and must be clearly differentiated from inertia provided by "traditional" rotating machinery. Instead, both TasNetwroks and Energy Networks Australia suggested alternative revision to the definition of inertia support services by adding the bolded text below:[303]

> ***Inertia support activity***
>
> An activity approved by AEMO under clause 5.20B.5(a) which may include installing or contracting for the provision of frequency control services, installing emergency protection schemes, contracting with Generators in relation to the operation of their generating units in specified conditions, **and installing or contracting fast frequency response delivered from inverter connected equipment.**

AEMO's noted that: [304]

> An inertia framework has recently been created, with mechanisms for inertia management. AEMO does not consider that any changes to the inertia framework are necessary for determining these PFR rule change proposals.

CS Energy and Ergon Energy and Energex considered that any reconsiderations of inertia and inertia support activities are complex and should be pursued separately to the current rule changes.[305]

### Stakeholder views on the draft determination

TasNetworks and ENA supported the decision in the draft determination to not change the definitions of *inertia* and *interia support activities*.[306] However, Meridian Powershop supported broadening the definition of *inertia* to include fast frequency response from inverter-connected plant.[307]

Meridian Powershop "does not believe the current framework adequately allows for inertia support by way of fast frequency response from inverter connected plant."[308]It encouraged the Commission to consider arrangements for inertia and inertia support activities.

#### Commission's analysis and conclusion

In relation to the proposed change to NER clause 5.20B.5(a), the Commission notes that the existing clause 5.20B.5(a) 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

303 Submissions on the consultation paper: TasNetworks, p. 6, Energy Networks Australia p. 2.

304 AEMO, Submission to the *Primary frequency response rule changes* Consultation paper, 31 October 2019, pg. 10

305 Submissions on the consultation paper: CS Energy, p. 16, Ergon Energy and Energex p. 2

306 Submissions to the draft determination: TasNetworks, p.2, ENA, p.2

307 Meridian Powershop, Submission to the draft determination, p.6.

308 Meridian Powershop, Submission to the draft determination, p.6.

generating unit or a synchronous condenser as per NER clause 5.20B.4(d). The following note is included in the NER following clause 5.20B.5(a)(3):[309]

> 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.

Clause 5.20B.5(a) allows for frequency control services, from inverter connected plant or otherwise, to be considered as 'inertia support activities' subject to approval by AEMO. The Commission notes that the existing arrangement for inertia support activities are inclusive of fast frequency response from inverter connected plant under the term, frequency control services. Therefore, the Commission do not consider there to be a benefit in making the proposed change to NER clause 5.20B.5(a).

In relation to the proposed change to the Chapter 10 definition of inertia, the Commission notes that the existing definition reflects the current operational approach that differentiates between physical inertia provided by synchronous machinery and fast frequency response provided by inverter connected equipment. The existing definition of inertia in the NER is:[310]

> 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*.

The Commission considers that inertia and fast frequency response are distinct services which perform different roles in the management of system frequency. Physical inertia from synchronous machines inherently slows the rate of frequency change caused by a contingency event. This is different to FFR, which actively injects power or reduces consumption to arrest the frequency change and revert the frequency back towards normal operating levels. Technologies that are capable of acting as a direct substitute for inertia by instantaneously and continuously maintaining local frequency have not yet been demonstrated as being reliable for operation at scale in large power systems. However, research suggests that these technologies are likely to become available for use in large power systems in the future.

The Commission considers that the existing definition of inertia reflects the current operational practise that differentiates between physical inertia provided by synchronous machines and fast frequency response provided by inverter connected plant. The proposed change would remove that distinction and result in inertia being a more general term that included any plant that is able to oppose a change in power system frequency.

The final rule is the same as the draft rule and does not include any change to the chapter 10 definition of inertia.

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309 NER clause 5.20B.5(a)

310 NER Chapter 10

The Commission notes that it could potentially consider incentive arrangements for fast frequency response as part of the R*emoval of disincentives to the provision of primary frequency response under normal operating conditions* rule change request as well as any other relevant rule change requests received.

# E LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this final rule determination.

## E.1 Final rule determination

In accordance with ss.102 and 103 of the NEL the Commission has made this final rule determination in relation to the rules proposed by AEMO and Dr. Sokolowski (which were consolidated by the Commission under s99 of the NEL on 19 December 2019).

The Commission’s reasons for making this final rule determination are set out in section 2.4.

A copy of the more preferable final rule is attached to and published with this final determination. Its key features are described in section 2.1, Chapter 4, and in further detail in Appendix A to D.

## E.2 Power to make the rule

The Commission is satisfied that the more preferable final rule falls within the subject matter about which the Commission may make rules. The more preferable final rule falls within s.34 of the NEL as it relates to:

- the operation of the NEM
- the activities of persons (including Registered Participants) participating in the NEM or involved in the operation of the national electricity system
- The operation of the national electricity system for the purposes of the safety, security and reliability of the system.

## E.3 Commission's considerations

In assessing the rule change request the Commission considered:

- it's powers under the NEL to make the rule
- the rule change request
- submissions received during first and second round consultation
- the Commission’s analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO
- the ongoing package of work being undertaken by the Commission in relation to frequency control frameworks.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[311]

311 Under s.33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions.[312] The more preferable final rule is compatible with AEMO's declared network functions because as it leaves those functions unchanged.

## E.4 Civil penalties

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

The Commission's final rule includes the addition of rule 4.4.2(c1) into the NER. The new provision that the Commission is recommending to the COAG Energy Council as civil penalty provisions is:

> (c1) 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*;

The Commission considers that this new provision should be classified as a civil penalty provisions because it will encourage compliance by the relevant parties. In addition, it is consistent with rule 4.4.2(b), which obliges a Generator's to ensure that all its generating units meet the technical requirements for frequency control in clause S5.2.5.11, and which is already classified as a civil penalty provision.

## E.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as conduct provisions.

The final rule does not amend any rules that are currently classified as conduct provisions under the NEL. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the final rule be classified as conduct provisions.

312 Section91(8) of the NEL.

# F SUMMARY OF OTHER ISSUES RAISED IN SUBMISSIONS

This appendix contains the Commission's response to issues raised by stakeholders that have otherwise not been discussed in the main body of this document.

Table F.1: **Summary of other issues raised in submissions to the consultation paper**

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| Snowy Hydro | p.1 | Snowy suggested that the proposed rule may conflict with Section 51(xxxi) of the Australian Constitution and recommends the AEMC should seek legal advice on the matter.<br>*"Section 51(xxxi) of the Australian Constitution empowers the Commonwealth to make laws with respect to "the acquisition of property on just terms from any State or person for any purpose in respect of which the Parliament has power to make laws...". ...The mandatory nature of the PFR and the direct benefit to AEMO as a result of the PFR strongly suggests it involves an acquisition of property, enlivening s51(xxxi). If that is correct, then the proposed compensation arrangements must be on "just terms" (as understood in Constitutional jurisprudence), or otherwise the PFR requirements risks being found constitutionally invalid.* | 1. The final rule does not amount to an acquisition of property as it does not constitute (a) a modification or extinguishment of property rights; and (b) a corresponding acquisition of property rights.<br>2. Section 51(xxxi) of the Constitution applies in relation to the NER as applied in the offshore areas of the States and Territories, and by equivalent Commonwealth legislation to the NER as applied in the Territories. However, it does not apply in relation to the NER as applied in the participating States.<br>3. The prohibitions that apply in the offshore areas and the Territories do not constitute a general limit on the AEMC's rule-making power.<br>For further discussion, see appendix a.5. |

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| Stanwell | pp. 4-5, 7 | Stanwell considered that the proposed rule would result in the headroom reserved by their generators to meet ramping requirements will be utilised for PFR.<br><br>Stanwell asked for clarification as to whether the proposal that generators are not penalised for PFR provision extends to ramping requirements.<br><br>Stanwell does not believe the proposed rule to be technology neutral as some generators, such as solar and wind, do not naturally preserve headroom and so will not provide PFR. | The Commission considers that a generator's obligation to comply with dispatch instructions encompasses the generator's ramping requirements and that this obligation is subject to the provision of PFR, as discussed in Appendix D.<br><br>The Commission considers the final rule to be technology neutral as it applies a universal obligation on all scheduled and semi-scheduled generators that are not exempt, subject to energy availability. |
| Alinta | p.3 | Alinta suggested fast ramping capabilities of large generators may be affected by the proposed rule change. | The Commission considers that a generator's obligation to comply with dispatch instructions encompasses the generator's ramping requirements and that this obligation is subject to the provision of PFR, as discussed in Appendix D. |
| IES | pp. 10-11 | IES recommended a mechanism similar to a two-sided version of causer pays is implemented as soon as possible. IES recommends to:<br><br>"Begin development work immediately on a prototype meter and settlement logic that would support wider participation in the proposed PFC market by any party, as well support any longer-term deviation pricing arrangement (through enhancement of the firmware)" | The Commission intends to consider the development of an effective valuation and payment mechanism for PFR through the assessment of the Removal of disincentives to the provision of primary frequency response rule change, as set out in the revised frequency control work plan |

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| Infigen | p.3 | Inifigen proposed that AEMO pursue the following approach: "AEMO could:<br>- Initially, seek a mandatory response from large synchronous units (200 MW+) and observe the resulting frequency performance (6-12 months); - If insufficient, then seek response from smaller synchronous units;<br>- Finally, if performance is still unsatisfactory and a market mechanism has not been developed, seek response from non-synchronous units, where cost of provision is likely to be highest." | The Commission has made this final rule informed by advice from AEMO and its expert consultant, that this reform will meet the immediate system need for effective frequency control in the NEM. However, the Commission also recognises that further reform will be needed in the future and will be considered through the Removal of disincentives to the provision of primary frequency control rule change as well as any other relevant rule change requests received. |
| ERM Power | pp.2, 10. | ERM suggested that AEMO should request the FOS to be reviewed as it's first priority in addressing frequency performance. ERM suggests the following approach to addressing frequency performance:<br>- Amend the Rules such that regulation FCAS can be supplied by AGC systems and PFR, as well as clarifying by which methods contingency FCAS must be provided.<br>- Insert a requirement into the Rules obligating all generators to provide PFR outside of the band from 49.60Hz to 50.40Hz.<br>- Rule changes mandating PFR should be put on hold "pending completion of the trial and research process as envisaged by the Frequency control framework review". | The Commission considers that further work needs to be done to understand the power system requirements for maintaining good frequency control and that this analysis should be undertaken through the second stage of the primary frequency response rule change process, the assessment of AEMO's Removal of disincentives to the provision of primary frequency response rule change request as well as any other relevant rule change requests received. |

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| Energy Networks Australia | p.2. | Energy Networks Australia suggested that a market mechanism may be required in the future but should be considered by the ESB in its post 2025 market design work. | As discussed in section 3.4 and appendix G, all market bodies intend to work collaboratively with the ESB's Post-2025 Market Design plan in ongoing reform of frequency control frameworks. |
| ARENA | p.2. | ARENA suggested any price signals for PFR should be based on the causer pays principles. When designing any future frameworks, ARENA encourages the AEMC to consider:<br>- the volume of PFR required on a regional basis<br>- how the need for PFR may be reduced<br>- potential changes to the capability and composition of the generation fleet, including the role of DER. | The Commission considers that further work needs to be done to understand the power system requirements for maintaining good frequency control and that this analysis should be undertaken through the second stage of the primary frequency response rule change process, the assessment of AEMO's *Removal of disincentives to the provision of primary frequency response* rule change request as well as any other relevant rule change requests received. |
| Delta Electricity | p.6. | Delta Electricity suggested that any frequency control objective should be defined by standards determined by the Reliability panel, implemented through clearly specified markets and subject to rigorous performance monitoring. Delta Electricity believes mandating security controls is only appropriate after all market options are exhausted, backed by sufficient evidence. Delta Electricity considers a redesigned MASS would deliver a more efficient solution than mandated Rules. | The Commission considers that further work needs to be done to understand the power system requirements for maintaining good frequency control and that this analysis should be undertaken through the second stage of the primary frequency response rule change process, the assessment of AEMO's *Removal of disincentives to the provision of primary frequency response* rule change request as well as any other relevant rule change requests |

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| | | | received. |
| Neoen | pp.1-2, 3. | Neoen requested an assessment of how PFR will be operationally managed and interact with current FCAS markets as well as the simultaneous creation of an FFR market. Neoen expects this analysis, including an assessment of the quantity of PFR required, to be carried out prior to implementing a significant rule. "AEMO should specify the magnitude of response expected within the NOFB. Then that capacity can be bought via auction, with more responsive plant able to offer a larger portion of rated capacity into the auction."<br>Neoen considered regional reserves for contingency to be a issue relating to the reclassification of contingency events and not a requirement for PFR.<br>Neoen supported a spot market for PFR services to be developed alongside a secondary contract market. | The Commission considers that further work needs to be done to understand the power system requirements for in relation to frequency control, building on the work AEMO is undertaking in its *Renewable Integration Study*. This analysis will be undertaken through by AEMO as part of the frequency control work plan as discussed in chapter 3. |
| AEC | pp.3, 10, 11-12 | The AEC considered AEMO's proposals not to be an appropriate solution for steady state stability of the power system (as opposed to resilience). Instead, the AEC recommends:<br>- Greater use of secondary control systems<br>- Refinement of the MASS<br>- Strengthening of the causer pays mechanism | The Commission considers that further work needs to be done to understand the power system requirements in relation to frequency control, building on the work AEMO is undertaking in its *Renewable Integration Study*. . This analysis will be undertaken through by AEMO as part of the frequency control work plan as discussed in chapter 3. |

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| | | AEC offers three prioritised approaches for the short-term preferable to AEMO's proposal:<br>- Competitive tenders<br>- Partially regulated such as that used in the UK<br>- Mandatory PFR with regulated payment The AEC also suggests that work is carried out to examine how the accuracy of forecasts for semi-scheduled generator output can be improved and causer pays can be strengthened to encourage use of battery storage by variable generation. | |
| Fluence | p.4. | "Fluence is willing to work closely with AEMO and AEMC to determine potential alternate solutions, be it regional procurement of FCAS via bilateral contracts, as done in other markets in similar situations, alternate market changes to AGC signals to ensure more accurate participation, or removing the disincentive for PFR, so more FCAS is bid into the market." | The Commission intends to consider the development of an effective valuation and payment mechanism for PFR through the assessment of the *Removal of disincentives to the provision of primary frequency response* rule change as well as any other relevant rule change requests received. |
| Neoen | p.4. | Neoen considered that a mandatory PFR obligation will make it more difficult for peaking plant to cover their contracts during a price spike. Neoen reasoned that non-scheduled generation increases after a price spike and raises frequency. Scheduled and semi-scheduled generation online that is covered by the mandatory PFR requirement, such as peaking plant who prefer to operate at times of price spikes, would have to respond to the | The Commission considers that a mandatory approach applied to a broad cross-section of the generating fleet should mean that the impact on any individual generators is minimised.<br>However, the Commission acknowledges Neoen's concern and considers further investigation is needed in the context of market |

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| | | over-frequency environment by providing lower PFR, therefore causing a loss of energy output and resultant revenue. Neoen suggested a mandatory PFR requirement would exacerbate this effect. | participant categories and the responsibilities of non-scheduled generators. |
| TasNetworks | p.5. | TasNetworks suggested a simple mechanism in the short-term may be payment to PFR providers based on their positive causer pays contribution factors. | The Commission intends to consider the development of an effective valuation and payment mechanism for PFR through the assessment of the Removal of disincentives to the provision of primary frequency response rule change as well as any other relevant rule change requests received. |
| Energy Australia | pp. 2,6. | As an alternative to the proposed solution, Energy Australia suggested changes to the FOS and consideration of possible changes to the existing frameworks and markets to meet the new FOS. This may include changes to the causer pays arrangements as proposed by ERC0263. | The Commission considers that further work needs to be done to understand the power system requirements for in relation to frequency control. This analysis will be undertaken with support from AEMO as part of the frequency control work plan as discussed in chapter 3. |
| Powershop | pp. 4,7. | Powershop highlighted that hydro plant are subject to water release instructions which will impact their ability to provide PFR. | The Commission considers the exemption principles set out in the final rule, as discussed in Appendix B, provide guidance to generators' discussions with AEMO regarding their obligations with relation to these types of constraints. |
| Enel X | pp.3,7. | Enel X did not consider adequate quantitative evidence | The Commission considers that further work |

| STAKEHOLDER | PAGE REFER-ENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| | | has been provided by AEMO to determine whether a mandatory regulation is justified or whether all capable generators should be required to provide PFR. Enel X suggests the following steps to improving frequency performance in the NEM as an alternative to the proposed rule:<br>- Remove disincentives to PFR<br>- Improve AGC<br>- Regional procurement of FCAS<br>- Consideration of market based solutions | needs to be done to understand the power system requirements for in relation to frequency control. This analysis will be undertaken with support from AEMO as part of the frequency control work plan as discussed in chapter 3. |
| Bruce Miller | pp. 2. | Bruce Miller considered that the current FCAS markets and causer pays procedure should be reformed. Bruce Miller points to the inefficient dispatch of FCAS during the 25 August 2018 event and notes that generators that did not follow the NEMDE signals in QLD despite their adverse impact on region frequency would have been penalised under the current causer pays mechanism. | The Commission considers that further work needs to be done to understand the power system requirements for in relation to frequency control. This analysis will be undertaken with support from AEMO as part of the frequency control work plan as discussed in chapter 3. |

Table F.2: **Summary of other issues raised in submissions to the draft determination**

| STAKEHOLDER | PAGE REFERENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| Snowy Hydro | 6 | Snowy Hydro argued the mandatory PFR rule violates the technology neutrality principle because it only applies to Scheduled and Semi-scheduled generators (providing a possible advantage to Non-Scheduled Generators). | The technology neutrality principle is that the Rules should not target a particular technology, or be designed with a particular set of technologies in mind.<br>The Commission considers the final rule to be technology neutral as it applies a universal obligation on all scheduled and semi-scheduled generators that are not exempt, subject to energy availability. |
| Clean Energy Council | 5 | The Clean Energy Council stated that: "[t]he draft rule includes a prohibition on any generators making modifications to their plant to meet the technical requirements prior to receiving AEMO's response and approval. The CEC does not support this element of the draft rule. We suggest this prohibition is removed and generators should be permitted to continue to modify their plant as they see fit as usual under the NER." | The final rule does not prohibit generators making modifications to their plant prior to receiving AEMO's response and approval. |
| AEC | 3 | The AEC proposed that the mandatory PFR requirement may be also applied to Scheduled Loads such as pumps. | In its submission to the consultation paper, AEMO advised that most scheduled loads, with the exception of battery energy storage systems, are incapable of providing PFR and that the PFRR should not apply to scheduled loads at this time. As such, the Commission has not applied the mandatory PFR rule to |

| STAKEHOLDER | PAGE REFER-ENCE | ISSUE | AEMC RESPONSE |
|---|---|---|---|
| | | | Scheduled Loads. |
| Delta | 5 | Delta recommended that all other generators in a region should only have to provide the same deadband as the least capable generator in that deadband (i.e. the one with the widest deadband). | The final rule allows AEMO to specify an appropriate deadband for each individual generator, balancing out system needs and the impact on the individual. |
| AGL | 2 | AGL requested that the Commission provide guidance on how contingency FCAS providers are remunerated for provision of response inside the normal operating frequency band. | The Commission considers that this is a matter for AEMO to determine through the MASS.<br><br>In February 2019, AEMO published a draft MASS that recognises the value of frequency response provided from the moment a contingency event is noticed on the system. This approach will value frequency response provided by an enabled FCAS provider inside the normal operating frequency band. |

# G FCAS MARKET ANALYSIS

### Overview

The Commission expects that a mandatory primary frequency response requirement would increase participation in contingency and regulation FCAS markets. In the short term, this is likely to reduce FCAS prices, lowering costs for consumers.

However, there are many factors that influence FCAS prices. In this context, it is useful to examine how other factors such as separation events, changes in procured FCAS volumes, and energy market prices have affected FCAS prices historically.

### Historical FCAS prices

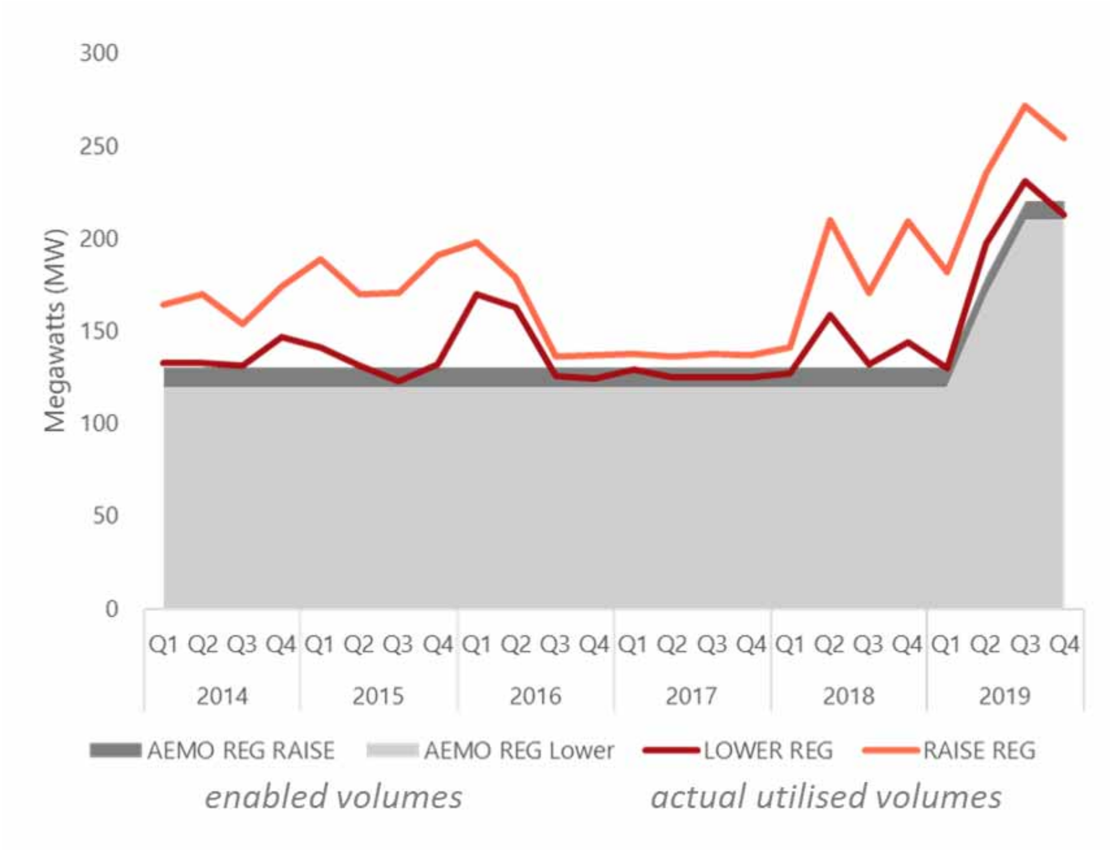
In recent times AEMO has increased the base quantity of regulation FCAS that it procures to levels that are similar to those seen at the start of the NEM. From NEM start, AEMO (then NEMMCO) enabled 250MW of the global regulation raise service and 250MW of the global regulation lower service. Between July 2003 and June 2006, it lowered the base quantity for these services to 130MW/120MW (raise/lower).[313] The procurement quantity for services remained at these levels until 22 March 2019, when AEMO commenced a program to increase regulation FCAS volumes in response to poor frequency performance during normal operation. AEMO gradually increased the volumes for regulation services up to 220MW/210MW (raise/lower) as of May 2019, where they have remained since.[314] Figure G.1 shows this recent increase in AEMO's baseline enabled regulation FCAS volumes, and the actual amounts of regulation FCAS procured from the market.[315]

313 [1] NEMMCO, *Frequency control ancillary services review – issues paper*, December 2006, p.15

314 AEMO, Factsheet: Regulation FCAS Update - June 2019.

315 AER, 2020, *Quarterly average FCAS enablement amount by services*, CSV data.

**Figure G.1: Quarterly enabled and actual regulation FCAS volumes**




Source: AER, 2020, *Quarterly average FCAS enablement amount by services*, CSV data.

Note: Global regulation raise and lower services have a base level of enablement, shown above in grey. Actual procured volumes can, and often do, exceed the base value. One reason for regulation volumes to exceed the base value is the impact of accumulated time error. Time error is a measure of the cumulative frequency deviation.AEMO increases the requirement for regulation services above the base values in response to accumulated time error. For example, if the base enablement values are 130/120MW raise/lower, and the time error is outside the ±1.5 second band, regulation FCAS providers will deliver an extra 60 MW of regulation for each 1-second deviation outside this band. (See: AEMO, *Constraint Implementation Guidelines*, June 2015, p.27.)

Note: Islanding events can also increase actual volumes above base enabled volumes. For example, during the extended outage of the Basslink interconnector during 2015 and 2016, AEMO required the same amount of regulation FCAS for the mainland, but an additional ~50 MW for Tasmania.

Similarly, AEMO has recently made changes to its assumptions in relation to load relief that have the effect of increasing the quantity of contingency FCAS that is procured in the NEM.

The amount of contingency FCAS it procures is equal to the size of the largest credible contingency minus assumed load relief. Between September and January 2019, AEMO progressively reduced assumed mainland load relief from 1.5% to 0.5%.[316] Figure G.2 shows the actual volumes for contingency FCAS through to the end of 2019. A slight increase in procured contingency FCAS volumes is evident in Q4 2019. While this change is not significantly higher than average volumes over the past seven years, further increases in contingency FCAS volumes are expected due to the changes in load relief when the data for Q1 2020 becomes available..[317]

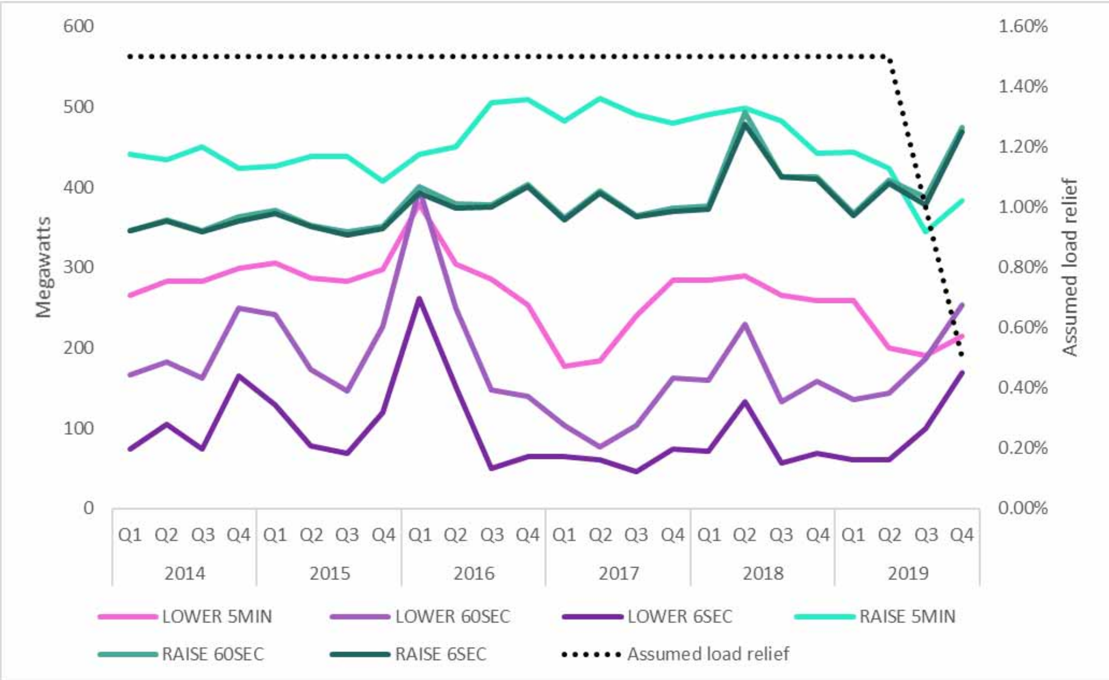
The impact of the recent changes to load relief is expected to be less strong in relation to the volume for the delayed, 5 minute, raise and lower services. This is due to the impact of the co-optimisation of the delayed and regulation services. The dispatch of delayed and regulation FCAS services are co-optimised, meaning that increasing the amount of regulation FCAS purchased will reduce the amount of delayed contingency FCAS services purchased.[318]

316 AEMO, 2019, *Review of NEM load relief: November 2019 update*, factsheet; AEMO, Market notice - 72529 , 14 January 2020.

317 AER, 2020, *Quarterly global FCAS prices by services*, CSV data.

318 AEMO, 2017, *FCAS Model in NEMDE: scaling, enablement, and co-optimisation of FCAS offers in central dispatch*, published May 2017, p. 15.

**Figure G.2: Quarterly average procured volumes of contingency FCAS with load relief**

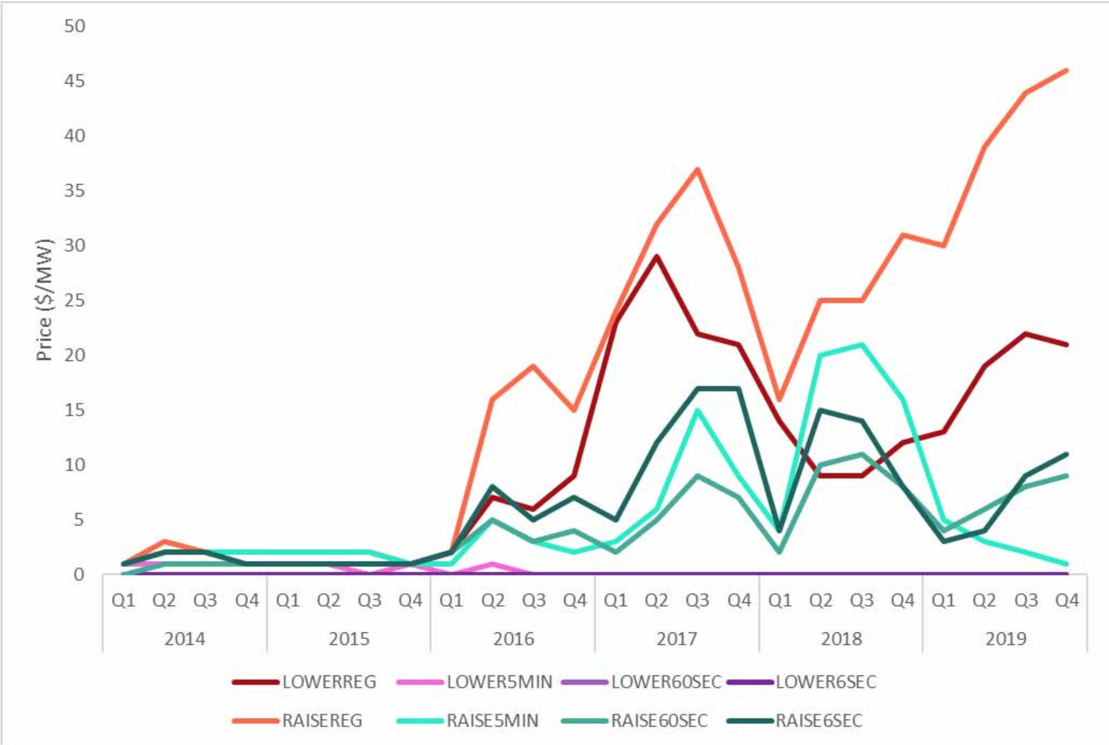



Source: AER, 2020, *Quarterly global FCAS prices by services*, CSV data.

FCAS prices vary independent of procured volumes. Figure G.3 shows the increase in quarterly regulation and contingency FCAS prices for the period 2013-2019.[319] While the increase in FCAS prices during 2019, coincide with increased enablement volumes during that period, FCAS prices also spiked between 2016 and 2018 when enabled volumes were relatively stable.

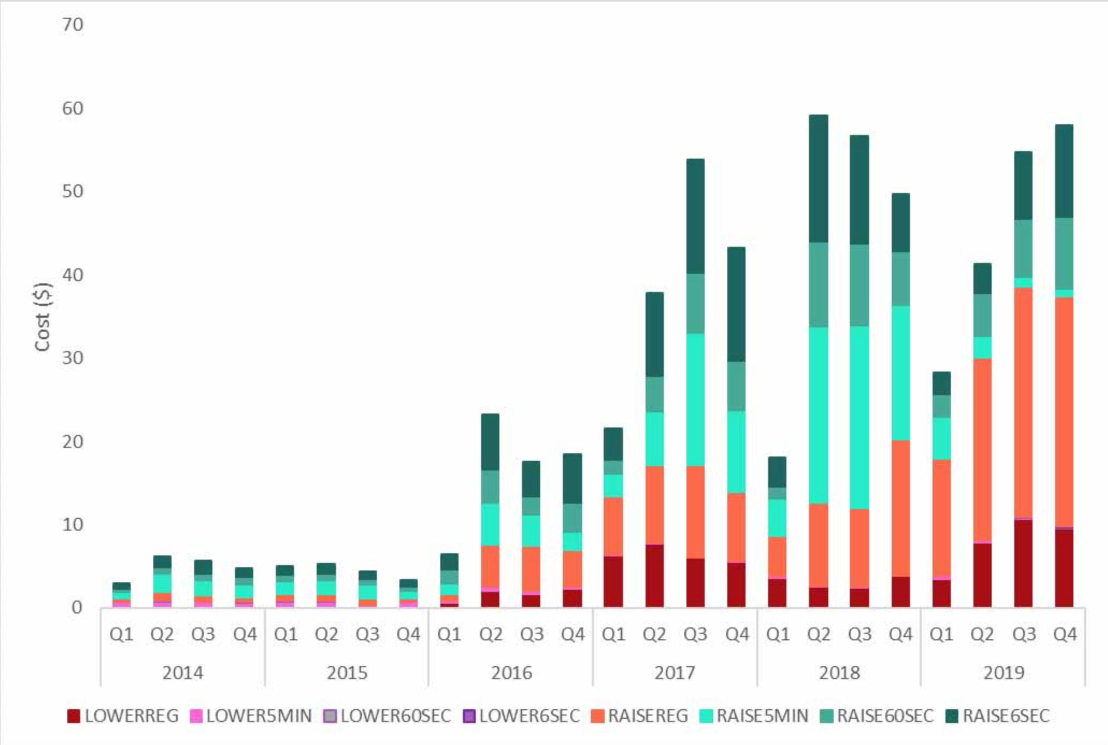
319 AER, 2020, *Quarterly global FCAS prices by services*, CSV data. Accessed at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/quarterly-global-fcas-prices-by-services

**Figure G.3: Quarterly global FCAS prices by service**




Source: AER, 2020, *Quarterly global FCAS prices by services*, CSV data.

**Figure G.4:** Quarterly FCAS costs by service




Source: AER, 2020, *Quarterly global FCAS costs by services*, CSV data.

### Impact of regional islanding

Separation events also have significant effects on FCAS prices and volumes

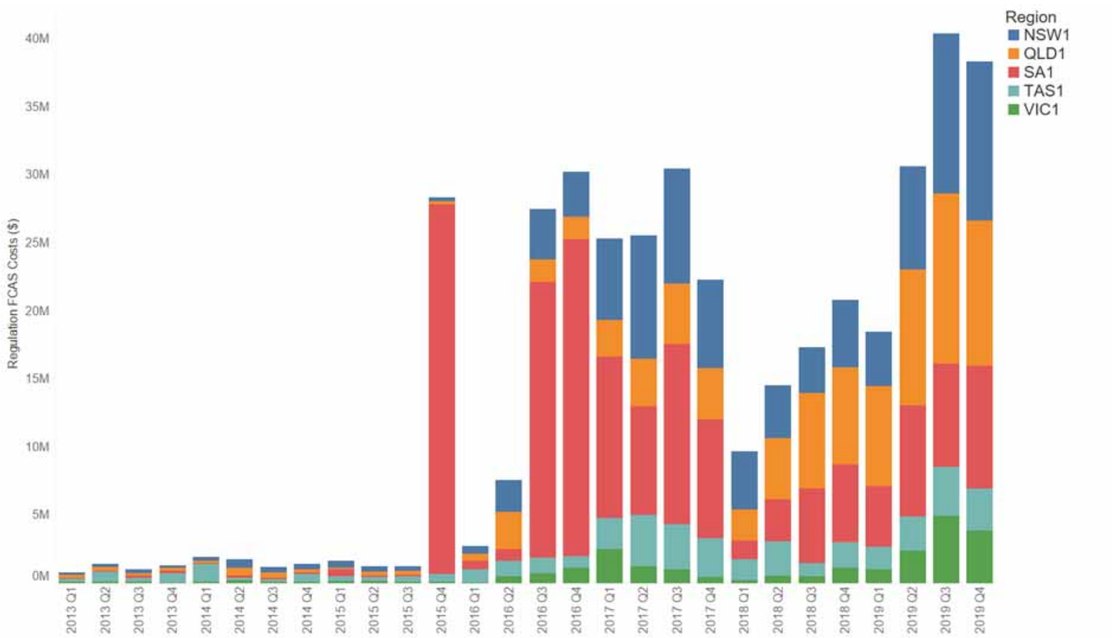
For example, the spike in the cost of regulation services in Q4 2015, shown in Figure G.5, was due to multiple outages at the Heywood interconnector in October and November 2015.[320] The Heywood Interconnector is a double circuit transmission line that provides an AC connection between South Australia and the Victoria. Prior to Q4 2015, the total cost of regulation FCAS services was usually under $1 million per quarter across the NEM. The cost of regulation FCAS just between 11 October and 10 November 2015 was approximately $27 million.

320 AEMO, 2015, *NEM – Market Event Report – High FCAS Prices in South Australia: October and November 2015,* published December 2015. Accessed at: https://aemo.com.au/-/media/Files/PDF/NEM--Market-Event-Report--High-FCAS-Price-in-SA--October-and-November-2015.pdf

Similarly, during this period, the quantity of procured FCAS significantly increased for all services, with lower 5 minute and lower 60 seconds contingency services doubling and trebling, respectively.

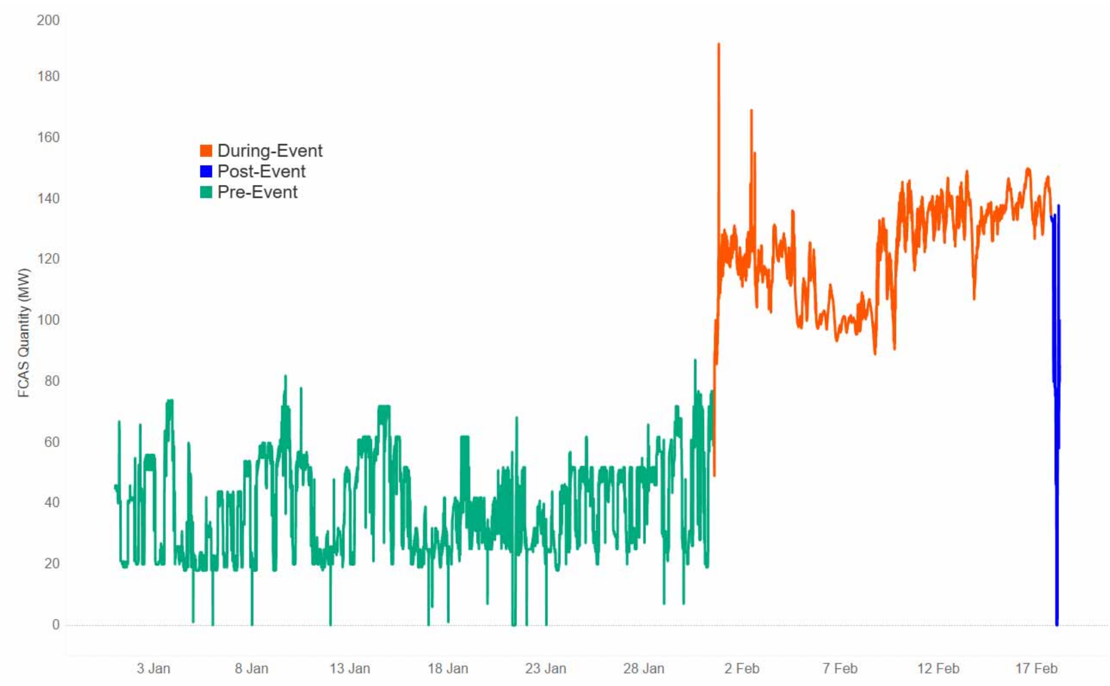
A similar event occurred earlier this year. Following the separation of the Heywood interconnector on 31 January 2020, the volumes and overall costs for regulation and contingency services in South Australia increased dramatically while South Australia was islanded between 31 January 2020 and 17 February 2020. In total,  the cost of contingency and regulation FCAS in South Australia  during the event was $94.8 million.

**Figure G.5: Total costs of regulation services by region**




Source: AER, *Quarterly local FCAS prices by services - New South Wales, Queensland, South Australia, Tasmania and Victoria*, CSV data

**Figure G.6: Quantity of 60 second lower contingency services procured in South Australia 1 January to 17 February 2020**



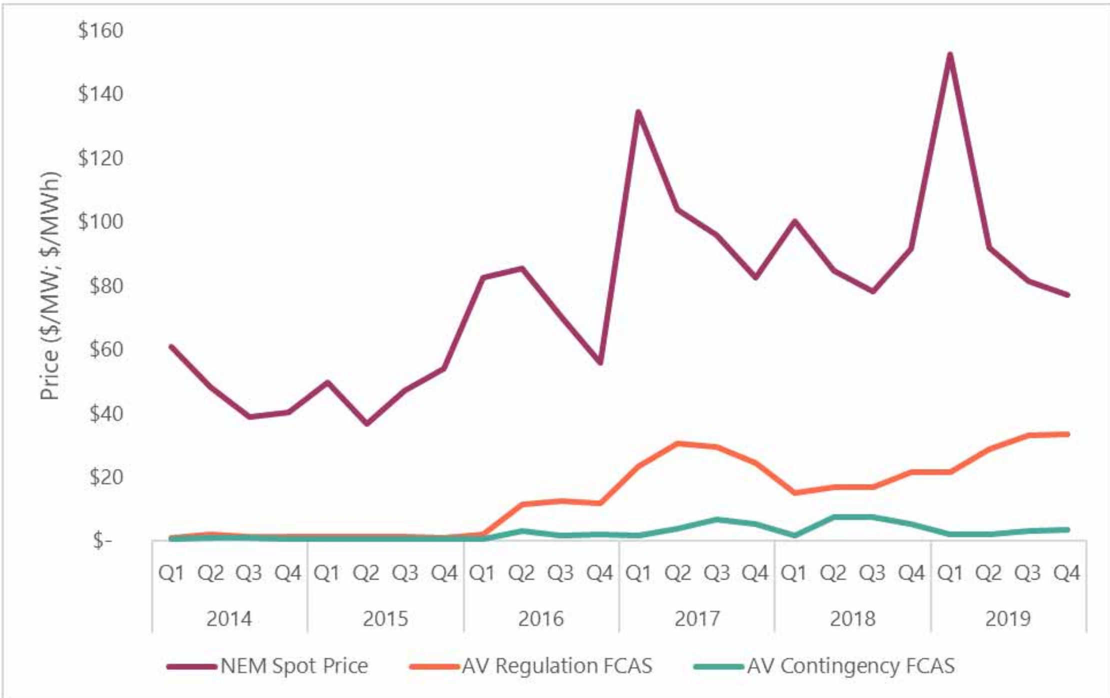

Source: AEMC analysis of MMS database.

### Relationship between energy and FCAS prices

FCAS prices are related to wholesale energy market prices, and high energy market prices often correlate withincreases in FCAS prices. Figure G.7 shows that the relationship between average prices for regulation FCAS and wholesale energy market prices from 2016 through to 2019.[321]

321 AER, 2020, *Quarterly* global FCAS prices by services, CSV data. Accessed at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/quarterly-global-fcas-prices-by-services; AER, 2020, Quarterly volume weighted average spot prices – regions, CSV data. Accessed at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/quarterly-volume-weighted-average-spot-prices-regions

**Figure G.7: NEM wholesale market price ($/MWh) and average contingency and regulation prices ($/MW)**

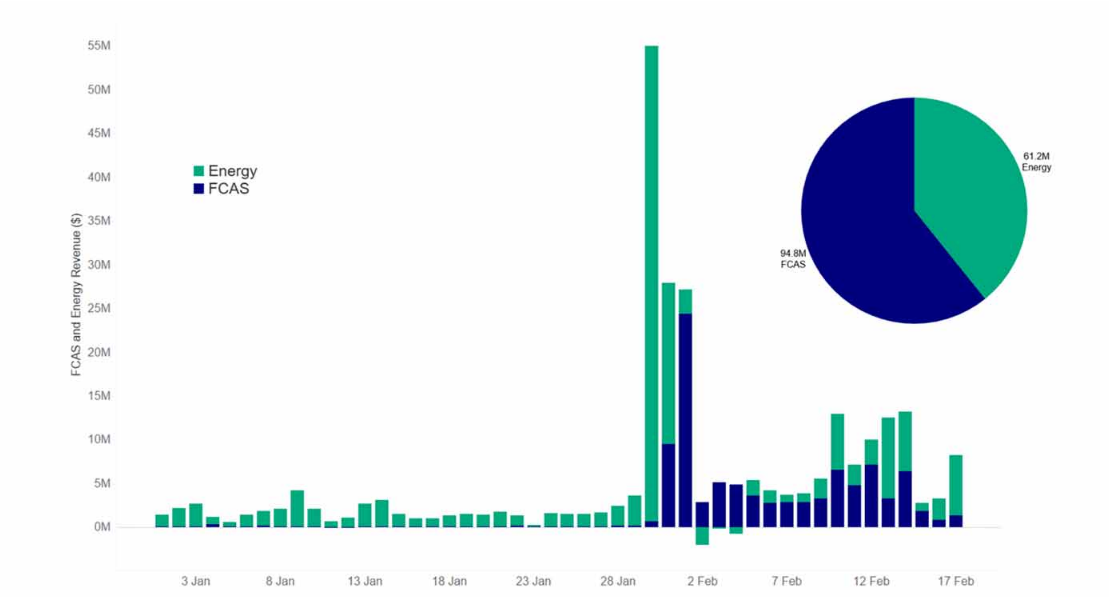



Source: AER, 2020, *Quarterly* global FCAS prices by services, CSV data. Accessed at: https://www.aer.gov.au/wholesale-markets/wholesale-statistics/quarterly-global-fcas-prices-by-services; AER, 2020, Quarterly volume weighted average spot prices – regions, CSV data.

Figure G.8 shows that, during the recent South Australian islanding event in January 2020, energy costs totalled $61.2 million, around 39% of overall costs.[322]

322 percentage of a combined total of $156 million for FCAS and energy costs during the period.

## Figure G.8: Daily FCAS and energy costs in South Australia: 1 January to 17 February 2020




Source: AEMC analysis of MMS database.